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UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 **Effective: March 29, 2022**

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STATEMENT OF REASONS

UGI UTILITIES, INC. – GAS DIVISION
2022 Base Rate Case
Docket No. R-2021-3030218

STATEMENT OF REASONS

I. INTRODUCTION

UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") is filing Supplement No. 32 to UGI Gas Tariff – Pa. P.U.C. Nos. 7 and 7S ("Supplement No. 32"), with a proposed effective date of March 29, 2022. The rates set forth in Supplement No. 32, if approved by the Pennsylvania Public Utility Commission ("Commission"), would increase UGI Gas's annual jurisdictional revenues by $82.7 million, or by 7.8%. In addition, the Company proposes to complete its transition to uniform rates, which began in the 2019 base rate case at Docket No. R-2018-3006814 ("2019 Rate Case"), for Rates N/NT and Rate DS. Supplement No. 32 also proposes additional changes to tariff rates, riders, and tariff terms and conditions as described in the filing.

The following rate impact analysis applies to UGI Gas's customers. It assumes that the Company's proposals for full rate relief and for uniform rate transition are accepted.

Average Residential Heating Customer Bill Impact

		Total Monthly Bill Impact			
	Average Usage	Current	Proposed	Increase (Decrease)	Total
All Customers	73.1 Ccf	$ 98.62	$ 108.01	$ 9.39	9.5%

Average Commercial Heating Customer Bill Impact

		Total Monthly Bill Impact			
	Average Usage	Current	Proposed	Increase (Decrease)	Total
Former North	28.8 Mcf	$ 307.00	$ 330.09	$ 23.09	7.5%
All Others	28.8 Mcf	$ 317.93	$ 330.09	$ 12.16	3.8%

Average Industrial Customer Bill Impact					
		Total Monthly Bill Impact			
	Average Usage	Current	Proposed	Increase (Decrease)	Total
Former North	92.4 Mcf	$ 931.45	$ 993.83	$ 62.38	6.7%
All Others	92.4 Mcf	$ 966.55	$ 993.83	$ 27.28	2.8%

UGI Gas makes this tariff filing principally: (1) to allow it to earn a fair return on investments used and useful to serve the public safely and reliably; (2) to support ongoing Commission-approved infrastructure replacement programs designed to enhance safety and reliability; (3) to enhance information technology ("IT") systems; (4) to implement a Weather Normalization Adjustment ("WNA") tariff rider, which limits the variability of over- or under-collections of non-gas margin revenues due to weather; and (4) to recover higher levels of certain operating expenses necessary for the provision of safe and reliable gas distribution service. Each of these reasons is discussed in more detail below and in the Company's testimony. As compared to current plant and base rate levels reflected in existing rates, UGI Gas projects an increase of approximately $795 million in gross plant through the Fully Projected Future Test Year ending September 30, 2023 ("FPFTY"). Accordingly, this revenue increase is essential to attract the investments necessary to operate and maintain safe, reliable and customer-focused natural gas distribution services.

II. REASONS FOR THE REQUESTED REVENUE INCREASE

1. Fair return on investments used to serve the public

A variety of circumstances will prevent UGI Gas from earning a fair rate of return at present rate levels. As reflected in UGI Gas Exhibit A (Fully Projected), the Company's operations are projected to produce an overall return on rate base of 6.13%, which equates to a return on common equity of only 7.89% for the FPFTY. As explained by UGI Gas witness Paul R. Moul (UGI Gas

Statement No. 6), those returns are not adequate based on applicable financial analysis and the risks confronted by UGI Gas. Unless UGI Gas receives the requested rate relief, its returns will decline. This will jeopardize its ability to attract capital necessary for system reliability, safety, and customer service.

2. Support for Commission-approved infrastructure replacement programs

Significant capital investment in the distribution system is the primary driver for the requested rate relief in this proceeding. Upgrading and modernizing the distribution system facilitates the provision of safe, reliable, and reasonable service to customers. Accordingly, the Company is replacing its non-contemporary infrastructure at an accelerated pace, as described in the Company's Commission-approved Second Long Term Infrastructure Improvement Plan ("LTIIP").[1] Through the Second LTIIP, the Company will invest approximately $1.3 billion on infrastructure improvements between 2020 and 2024, which will strengthen and modernize distribution facilities, in part through its Commission-approved programmatic elimination of all cast iron and bare steel mains on its system. In addition, UGI Gas continues to make system investments to serve new and existing residential and commercial customers, convert existing residences and commercial locations to natural gas (from other fuel sources), and improve critical information systems, as discussed further in subpart 3 below and in the Company's testimony.

3. Enhanced information technology systems, business processes and personnel effectiveness

The Company has improved its technology and employee training resources over the past several years. In particular, the Company continues to implement UGI-1, an initiative designed to modernize the processes and information system tools used by its employees across its system.

[1] *See Petition of UGI Utilities, Inc. – Gas Division for Approval of its Second Long Term Infrastructure Improvement Plan*, Docket No. P-2019-3012337 (Opinion and Order entered December 19, 2019).

UGI-1 is making the Company more effective in all aspects of its business, including customer calls, billing, new construction, operations and maintenance ("O&M") activities, and emergency response. As part of this initiative, the Company also continues its UGI Next Information Technology Enterprise ("UNITE") project, creating next generation technology solutions to improve the service experience of its customers, and improve efficiency. Specifically, UGI Gas implemented a new customer information system (UNITE Phase I) in 2017 and replaced its Enterprise Resource Planning financial and supply chain systems (UNITE Phase II) in 2019. The Company is in the process of implementing Phase III of UNITE, which consists of the Enterprise Performance Management ("EPM") project and the larger Enterprise Asset Management ("EAM") project, a multi-year, multi-phase project with the end goal of enhanced asset management capabilities and supporting applications. In October 2020, the EPM project introduced new capital budgeting and forecasting capabilities, which were integrated with the Company's Enterprise Resource Planning and fixed asset and tax systems. In mid-2021, the Company kicked off the EAM's Asset Data Collection phase, which will identify and standardize the retrieval of asset data information across UGI.

4. Employee compensation and cost increases

Finally, UGI Gas adopted needed annual wage and salary increases and has made certain compensation adjustments to attract, maintain, and promote a highly qualified work force and will continue to do so, where reasonable. As part of this case, the Company has proposed to increase compensation for certain employees in order to be competitive and to maintain its skilled workforce. These changes are discussed in the testimony of UGI Gas witness Christopher R. Brown (UGI Gas Statement No. 1) and Timothy J. Angstadt (UGI Gas Statement No. 9). UGI Gas also experienced other general price increases for necessary products and services.

Through these and other efforts, UGI Gas has made major strides toward modernizing its operations and has seen stable customer growth over time. However, forecasted cost increases and changes in per customer usage, which are described in the Company's testimony, will produce an inadequate rate of return on investments at present rates.

III. TRANSITION TO FULLY UNIFORM RATES, TERMS AND CONDITIONS

On October 4, 2019, the Commission entered an Opinion and Order in the Company's 2019 Rate Case, which approved a unified rate structure for all rate classes except for Rates N/NT and Rate DS. As approved, the Company used a consolidated revenue requirement to establish uniform distribution and purchased gas cost rates, except for the former North Rate District customers on Rates N/NT and Rate DS.

In this case, the Company is proposing to take the remaining step to unify Rates N/NT and Rate DS. Doing so will achieve uniform class rates for distribution service throughout the entire service territory. The impact of these changes is discussed in the testimony of UGI Gas witness Sherry A. Epler (UGI Gas Statement No. 8).

The Company's efforts to unify its rates, rules and regulations has provided specific customer, administrative, and competitive benefits. Eliminating the Company's rate districts[2] facilitated more uniform offerings, services, and communications to customers (*e.g.* tariff administration, bill inserts, notices, and press releases), including the expansion of the Company's Energy Efficiency and Conservation ("EE&C") program to customers in the former Central Rate

[2] On September 20, 2018, the Commission approved the Joint Petition for Settlement filed in the Company's Merger proceeding at Docket Nos. A-2018-3000381, A-2018-3000382, and A-2018-3000383. As a result of the Merger, the then-existing UGI natural gas distribution companies (UGI-GD, UGI-PNG and UGI-CPG) were merged into one resulting entity, UGI Gas. Accordingly, UGI-GD became the UGI South Rate District; UGI-PNG became the UGI North Rate District; and UGI-CPG became the UGI Central Rate District. The Merger was completed on October 1, 2018, and UGI Gas commenced operations under the three rate district structure approved as part of the Merger settlement.

District. UGI Gas's customers also now receive uniform price-to-compare notifications applicable to the entire service territory.

IV. MANAGEMENT EFFECTIVENESS

UGI Gas has focused on a number of areas to enhance and improve the quality and effectiveness of its management performance. These efforts include:

Customer Service

- Finishing in first or second in the J.D. Power award for customer satisfaction among utilities in each of the last nine years, and winning the J.D. Power #1 in Customer Satisfaction award a total of eight times since UGI was first included in the survey in 2003 by J.D. Power. UGI was also named a 2021 "Customer Champion" by Escalant.

Reliability

- Modernizing the distribution system by aggressively replacing aged infrastructure with the highest percentage of contemporary materials (*i.e.*, 90%) in the Commonwealth.

- Driving significant reductions in the levels of new leaks found, including a 28.6% reduction in C Leaks, a 50.3% reduction in B Leaks and a 47.7% reduction in A Leaks since 2016.

Safety

- Developing and implementing numerous safety improvement initiatives to reduce injuries and motor vehicle accidents including a focus on fostering an enhanced safety culture across the Company.

- Winning the 2021 American Gas Association Safety Awareness Video Excellence ("SAVE") award for being an outstanding contributor to natural gas communications on safety and education.

- Avoiding accidents through the "Near Miss/Good Catch" ("NMGC") program, which aids human performance, incorporating learnings from actual incidents that had the potential to but did not result in harm, damage or injury.

COVID Response

- Mitigating hardships experienced by customers through the Emergency Relief Program ("ERP"), which assisted those economically impacted by the Pandemic from October through December 2020. The Company awarded over $198,000 in grants to approximately 1,500 residential customers and instituted 1,800 payment agreements to collect over $1.5 million.

Environmental

- Administering a voluntary service territory-wide EE&C Plan with a comprehensive portfolio of energy efficiency and conservation programs designed to assist customers in saving energy through various cost-effective measures.

- Reducing GHG emissions by successfully converting more than 100,000 coal and fuel oil customers to more environmentally-friendly natural gas over the past decade and switching qualifying customers to gas through UGI Gas's recent line extension tariff rules adopted in the 2020 Gas Rate Case.

- Fostering clean fuel adoption, as twelve percent of UGI Gas's fleet includes compressed natural gas fueled vehicles ("NGVs"). These vehicles provide significant reductions in carbon emissions and serve to demonstrate the benefits existing today for NGVs to both produce favorable operating costs as well as improve the environment.

- Incorporating renewable natural gas ("RNG") into the gas supply portfolio from Archaea Energy's Keystone Landfill, which is the largest RNG facility in the world, and facilitating opportunities for the voluntary sale of RNG credits to interested parties both in Pennsylvania and abroad, thus bolstering revenue streams for commercial and agricultural entities in the Commonwealth.

Community Engagement

- Volunteering more than 31,000 hours of work and personal time to assist the Company's communities in 2020. Combined with corporate contributions and retiree contributions, total support provided to United Way agencies serving communities in the UGI Gas service territory in 2020 totaled more than $551,000.

Diversity & Inclusion

- Developing the Belonging, Inclusion, Diversity and Equity ("BIDE") initiative, which provides the blueprint for achieving greater diversity of thought, experience, culture, gender, race, and sexual orientation throughout the Company. Focusing on four core pillars of the business: Culture, Career, Community and Commerce, BIDE provides employees with a safe, welcoming, and inclusive work environment and develops a more diverse workforce.

- Strengthening community ties by contracting with Minority, Women, and Disabled Owned Businesses and spending more than $59 million in 2021 with qualifying businesses.

The identified initiatives and efforts, as described by the Company's witnesses, demonstrate UGI Gas's commitment to providing safe, reliable, and quality distribution service to its customers. The Company believes that its management efforts, system investments, and continued provision of safe and reliable service at reasonable rates, as detailed by the witnesses' testimony submitted in this case, all support an upward adjustment to the Company's rate of return. This upward adjustment is included in the 11.20% return on common equity requested by the Company and is discussed in the Direct Testimony of Paul R. Moul (UGI Gas Statement No. 6).

V. OVERVIEW OF FILING

Included with UGI Gas's filing are all of the supporting data required by the Commission's regulations. This information provides data for an historic test year ended September 30, 2021 ("HTY"), a future test year ("FTY") ending September 30, 2022, and a FPFTY. In accordance with permitted ratemaking procedures, the Company has elected to use the FPFTY as the basis for its proposed revenue change.

UGI Gas has followed Commission ratemaking practice in preparing its claims for rate base, operating revenues and operating expenses.

Rate Base. Rate base was determined based on depreciated original cost values for projected plant in service at the end of the FTY and FPFTY, respectively. The Company's rate base claim also includes reasonable estimates for materials and supplies inventory and cash working capital, as well as standard deductions for accumulated depreciation, accumulated deferred income taxes, and customer deposits. The Company's rate base claim is shown in summary form in Schedule C-1 to Exhibit A (Fully Projected) and is principally supported by the Direct Testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Operating Revenues. UGI Gas's *pro forma* test year operating revenues were derived from its fiscal year 2023 operating budget. As explained in the testimony of Sherry A. Epler (UGI Gas Statement No. 8) and other witnesses, operating revenues were annualized, normalized, and otherwise adjusted in accordance with standard ratemaking practice, as detailed in Schedules D-5 and D-5A of Exhibit A (Fully Projected) and the exhibits attached to Ms. Epler's testimony.

Operating Expenses. UGI Gas's *pro forma* test year operating expenses were derived from its fiscal year 2023 operating budget. As explained in the testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2) and other witnesses, certain operating expenses were annualized, normalized, and otherwise adjusted in accordance with standard ratemaking practice, as detailed in Section D of Exhibit A (Fully Projected). UGI Gas's claim for depreciation and amortization expense is supported by Exhibit C (Fully Projected) to the filing, and exhibits developed and supported by John F. Wiedmayer of Gannett Fleming Valuation & Rate Consultants, LLC (UGI Gas Statement No. 4). Mr. Wiedmayer's calculations are based on the straight-line, remaining life method previously approved for UGI Gas's operations by the Commission.

Income Taxes. UGI Gas's income tax expense was calculated using procedures previously accepted by the Commission. The Company's filing reflects the normalization of book-tax timing differences related to the use of accelerated depreciation for federal tax purposes and for the Company's repairs allowance deductions. As it relates to accelerated depreciation for state tax purposes, the Company uses flow-through for rate making purposes. The Company's tax claims are described and supported in the Direct Testimony of Nicole M. McKinney (UGI Gas Statement No. 7).

Revenue Allocation and Class Cost of Service. UGI Gas is proposing to allocate the revenue requirement to all customer classes based on the results of a consolidated class cost of service study. The Company also is proposing to establish uniform rates for Rates N/NT and Rate DS. The Company's proposed revenue allocation will move all rate classes substantially toward the overall system average rate of return. Additional details regarding the Company's cost of service study and revenue allocation are provided in the Direct Testimonies of Constance E. Heppenstall (UGI Gas Statement No. 10) and Sherry A. Epler (UGI Gas Statement No. 8).

Rate Design. In prior base rate proceedings, the Company has established a largely uniform rate structure and rate design across the former rate districts. As discussed above, UGI Gas adopted a single gas supply portfolio and unified rates to all customers but Rates N/NT and Rate DS customers. The Company also established a single Purchased Gas Cost ("PGC") rate and associated price to compare. As part of this proceeding, UGI Gas is proposing to complete the process of incorporating Rates N/NT and Rate DS into the uniform rate design applied to all other rate classes. Details are found in the Direct Testimony of Christopher R. Brown (UGI Gas Statement No. 1).

Other Tariff Changes. In this filing, the Company proposes relatively few changes to the terms and conditions approved by the Commission in the Company's most recent completed rate case. One such change is a proposed WNA tariff rider, which limits the variability of non-gas margin revenues due to weather variations during the heating season calendar months (e.g., October through May). A list of all proposed changes is identified in the Company's proposed tariff, Supplement No. 32 to UGI Gas Tariff – Pa. P.U.C. Nos. 7 and 7S.

VI. CONCLUSION

The proposed revenue increase is the minimum increase necessary for UGI Gas to continue providing safe and reliable service, to maintain the integrity of its financial ratings, to attract additional capital on reasonable terms, and to have a reasonable opportunity to earn a fair rate of return on property that is used and useful in providing natural gas service to the public within its service territory. The proposals contained in this filing will provide significant benefits to all stakeholders. Moreover, the Company's proposed revenue allocation and rate design are just and reasonable and non-discriminatory, as are the proposed changes made to the Company's general terms and conditions of service. Therefore, the rates, rules, and terms and conditions of service set forth in Supplement No. 32 to UGI Gas Tariff – Pa. P.U.C. Nos. 7 and 7S should be permitted to become effective as filed.

PLAIN LANGUAGE - STATEMENT OF REASONS

UGI UTILITIES, INC. – GAS DIVISION
2022 Base Rate Case
Docket No. R-2021-3030218

PLAIN LANGUAGE
STATEMENT OF REASONS

UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") has asked the Pennsylvania Public Utility Commission ("PUC" or the "Commission") to increase UGI Gas's annual jurisdictional revenues by $82.7 million, or by 7.8%, and finalize the transition to uniform rates, which began in the gas base rate case at Docket No. R-2018-3006814 ("2019 Base Rate Case"), for Rate N/NT and Rate DS customers. The percentage rate increase will vary by rate class. The main reasons for this proceeding are:

- UGI Gas continues to invest in gas plant needed to provide continued safe and reliable service. In the past five years, the Company has invested more than $982,000,000 in repairing and replacing its aging infrastructure.

- UGI Gas seeks to complete its transition to uniform rates, which began in the 2019 Base Rate Case, for Rate N/NT and Rate DS. Doing so will achieve uniform class rates for distribution service throughout the entire service territory.

- UGI Gas proposes a Weather Normalization Adjustment ("WNA") tariff rider, which limits the variability of over- or under-collections of non-gas margin revenues due to weather during the heating season (*i.e.*, October through May).

- Without substantial rate relief, UGI Gas will not be able to earn a fair return on its investment used to serve the public and, if not addressed, this could adversely affect the integrity of its financial ratings and its ability to provide safe and reliable service to its customers.

UGI Gas designed the proposed rates for each customer class to recover its total required revenue. In allocating the revenue increase to the residential and non-residential customer classes, UGI Gas was guided by detailed studies of each rate class's cost of service. UGI Gas also considered and balanced other principles of rate design consistent with the Commission's approach to ratemaking.

Along with its rate increase, UGI Gas has filed all of the supporting data required by the Commission's regulations, as well as the written statements of eleven witnesses and numerous exhibits prepared by those witnesses. The data, testimony, and exhibits submitted by UGI Gas comply with the Commission's filing requirements. The proposed distribution revenue increase is the minimum increase necessary for UGI Gas to continue providing safe and reliable service to the public within its service territory.

SECTION 53.52 - FILING REQUIREMENTS

UGI UTILITIES, INC. – GAS DIVISION

Proposed Changes to UGI Utilities, Inc. – Gas Division, Supplement No. 32 to Original Tariff Nos. 7 and 7S

Information furnished with the filing of rate changes under
52 Pa. Code, Section 53.52

(a) Applicable to changes in terms and conditions of service.

(a)(1) The specific reason for each change.

The Company has provided a Statement of Reasons describing the necessity for the changes proposed in this filing.

(a)(2) The total number of customers served by the utility.

671,662 customers as of September 30, 2021.

(a)(3) A calculation of the number of customers, by tariff subdivision, whose bills will be affected by the change.

R/RT	616,132
N/NT	70,125
DS	1,392
LFD	602
XD	56
IS	363

(a)(4) The effect of the change on the utility's customers.

The specific effect by class is shown in UGI Gas Exhibit E – Proof of Revenue.

(a)(5) The effect, whether direct or indirect, of the proposed change on the utility's revenue and expenses.

The Company's proposal will change revenue and expenses, as shown on UGI Gas Exhibit A (Fully Projected), Schedule A-1. Individual adjustments to revenues and expenses are described in testimony and exhibits supporting the filing.

(a)(6) The effect of the change on the service rendered by the utility.

The filing will allow the Company to continue to provide safe and reliable service to its customers while maintaining high levels of customer satisfaction.

(a)(7) A list of factors considered by the utility in its determination to make the change. The list shall include a comprehensive statement as to why these factors were chosen and the relative importance of each. This subsection does not apply to a portion of the tariff change seeking a general rate increase as defined in 66 Pa.C.S. Section 1308 (relating to voluntary changes in rates).

The Company has provided a Statement of Reasons describing the numerous factors considered in its determination to make the filing. Please also see the Direct Testimony of Christopher R. Brown (UGI Gas Statement No. 1) for a summary of those factors.

(a)(8) Studies undertaken by the utility in order to draft its proposed change. This paragraph does not apply to a portion of the tariff change seeking a general rate increase as defined in 66 Pa.C.S. Section 1308.

Not applicable.

(a)(9) Customer polls taken and other documents, which indicate customer acceptance and desire for the proposed change.

The Company has not undertaken any polls.

(a)(10) Plans the utility has for introducing or implementing the change with respect to its customers.

The Company will notify customers of the proposed changes, including the proposed Weather Normalization Adjustment alternative ratemaking mechanism by a bill insert using the form of notices specified by the Commission at 52 Pa. Code 53.45. A copy of the notice will be provided together with an affidavit of compliance with the notice requirements. Upon approval, the Company will provide notice of Weather Normalization Adjustment approval and implementation in accordance with 66 Pa. C.S. § 1330 implementation requirements.

(a)(11) F.C.C. or FERC or Commission orders or rulings applicable to the filings.

The Company has experienced both increased uncollectible accounts expenses and increased costs in certain areas due to COVID-19. The Company's filing includes related claims in accordance with the Commission's May 13, 2020 Secretarial Letter regarding COVID-19 Cost Tracking and Creation of Regulatory Asset at Docket No. M-2020-3019775. The Company's recovery of certain extraordinary, nonrecurring incremental COVID-19 costs as part of this proceeding is discussed in the Direct Testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

The Company also adopted some revisions to its accounting practices in accordance with the findings made in a recent Federal Energy Regulatory Commission ("FERC") Audit at Docket No. FA20-3-000.

(b) Applicable to changes in rates.

(b)(1) Specific reason for each change.

The Company has provided a Statement of Reasons describing the necessity of this filing.

(b)(2) Utility's operating income statement ending not more than 120 days prior to filing date – historic year.

Please refer to UGI Gas Exhibit A (Historic), Schedule B-2. For future test year and fully projected future test year operating income statements, please refer to UGI Gas Exhibit A (Future), Schedule B-2, and UGI Gas Exhibit A (Fully Projected), Schedule B-2.

(b)(3) Number of customers, by tariff subdivision, whose bills will be increased.

Tariff Rate	Customers
R/RT	616,132
N/NT	70,125
DS (former North rate district)	389
LFD	602

(b)(4) Total increases, in dollars, by tariff subdivision, projected to an annual basis.

Please refer to UGI Gas Exhibit E – Proof of Revenue.

(b)(5) Number of customers, by tariff subdivision, whose bills will be decreased.

Tariff Rate	Customers
DS (former South & Central rate districts)	1,003
XD	56
IS	363

(b)(6) Total decreases, in dollars, by tariff subdivision, projected to an annual basis.

Please refer to UGI Gas Exhibit E – Proof of Revenue.

(c) Applicable to changes where increase for any tariff subdivision exceeds 3% of utility's operating revenue OR bills of more than 5% of customers will increase.

(c)(1) Rate of return for historic year and anticipated for future year.

Please refer to UGI Gas Exhibit A (Historic), Schedule A-1, UGI Gas Exhibit A (Future), Schedule A-1, and UGI Gas Exhibit A (Fully Projected), Schedule A-1.

(c)(2) Detailed balance sheet at the end of the historic year.

For the end of the historic year balance sheet, please refer to UGI Gas Exhibit A (Historic), Schedule B-1.

(c)(3) Summary, by detailed plant accounts, of book value of property of utility at end of historic year.

Please refer to UGI Gas Exhibit A (Historic), Schedule C-2, for the original cost book value of the property of the utility for the historic year.

(c)(4) Respective amount of the depreciation reserve applicable to each detailed plant account.

Please refer to UGI Gas Exhibit A (Historic), Schedule C-3, for the historic year depreciation reserve as of year-end, UGI Gas Exhibit A (Future), Schedule C-3, for the future test year depreciation reserve as of year-end, and UGI Gas Exhibit A (Fully Projected), Schedule C-3, for the fully projected future test year depreciation reserve as of year-end.

(c)(5) Statement of operating income, setting forth the operating revenues and expenses by detailed accounts – historic year.

Please refer to UGI Gas Exhibit A (Historic), Schedule B-2, for the historic year operating revenue and expenses.

(c)(6) Description of any major changes in the operating or financial condition of the utility occurring between the date of the balance sheet at end of the historic year and filing date.

None.

SECTION 53.62 - FILING REQUIREMENTS

UGI UTILITIES, INC. – GAS DIVISION

Proposed Supplement No. 32 to UGI Gas Tariff Nos. 7 and 7S

Information furnished pursuant to 52 Pa. Code, Section 53.62

§ 53.62. Additional information to be filed by gas utilities with gross annual intrastate operating revenues in excess of $40 million seeking a change in base rates.

In addition to information otherwise required to be filed by a jurisdictional natural gas distributor with gross intrastate annual operating revenues in excess of $40 million seeking a change in its base rates, each gas utility shall also file updates to the information required by § 53.64(c) (relating to filing requirements for natural gas distributors with gross intrastate annual operating revenues in excess of $40 million). In the case of a gas utility purchasing gas as defined at § 53.61(a) (relating to purpose) from an affiliated interest, it shall also file updates to the information required at § 53.65 (relating to special provisions relating to natural gas distributors with gross intrastate annual operating revenues in excess of $40 million with affiliated interests). These updates shall be made at the time the base rate case under 66 Pa.C.S. § 1308 (relating to voluntary changes in rates) is originally filed. Deficiencies in filing will be treated as set forth at § 53.51(c) (relating to general).

RESPONSE:

Please see the response to III-E-30.

SECTION 53.53 - VALUATION

I-A-1

Request:

Provide a corporate history (include the dates of original incorporation, subsequent mergers and/or acquisitions). Indicate all counties and cities and other governmental subdivisions to which service is provided (including service areas outside the state), and the total population in the area served.

Response:

UGI Utilities, Inc. began its modern corporate existence as part of a consolidation of a number of predecessor natural gas and electric public utilities into The United Gas Improvement Company, as approved by the Pennsylvania Public Utility Commission ("Commission") on June 16, 1952 at Docket No. A.78264. In 1968, The United Gas Improvement Company changed its name to UGI Corporation. In 1971, UGI Corporation's gas operations were consolidated into a gas division ("UGI Gas") located in Reading, Pennsylvania. In January 2019, UGI Gas relocated its headquarters to Denver, Pennsylvania. UGI Corporation's electric operations ("UGI Electric") operates in a separate electric division headquartered in northeastern Pennsylvania. In 1992, as part of a further corporate restructuring, UGI Corporation changed its name to UGI Utilities, and became a wholly-owned subsidiary of a new holding company which adopted the name UGI Corporation.

UGI Utilities, Inc. increased its gas operations in 2006 and 2008 with the incorporation of two subsidiary gas utilities – UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas, Inc. ("UGI CPG"), respectively. UGI PNG began its operations following the close, on August 24, 2006, of UGI Corporation's purchase of the natural gas distribution assets from the former PG Energy Division of Southern Union Company, as authorized by a Commission Order entered on August 18, 2006, at Docket No. A-120011F200. UGI CPG, formerly PPL Gas Utilities Corporation ("PPL Gas"), was acquired by UGI Utilities effective October 1, 2008, as authorized by a Commission Order entered on August 21, 2008, at Docket Nos. A-2008-2034045 et al. Prior to that acquisition, PPL Gas itself was the result of several mergers and acquisitions authorized by the Commission. See, e.g., Joint application of PPL Gas Utilities Corp., North Penn Gas Company, and PFG Gas, Inc., Docket Nos. A-125127, et al. (Order entered July 12, 2004); Application of Allied Gas Company et al., Docket No. A-120650F002 (order approving merger and restructuring entered January 27, 1995).

I-A-1 (Continued)

In accordance with authority granted in a Commission Opinion and Order entered on September 20, 2018 at Docket Nos. A-2018-3000381 et seq., UGI PNG and UGI CPG merged into UGI Gas effective October 1, 2018. The former service territories of UGI PNG, UGI Gas and UGI CPG were organized into the North, South and Central Rate Districts of UGI Gas, respectively. By a Commission Opinion and Order entered on October 4, 2019 at Docket Nos. R-2018-3006814 et seq., the Commission approved UGI Gas's proposal to eliminate the Rate District structure and move most rate classes to uniform distribution rates for a single UGI Gas service territory encompassing the aggregate service territory of the former North, South, and Central Rate Districts.

The list of communities served by UGI Gas is set forth in its tariff provided in this rate filing and which is available on the Commission's website at: https://www.puc.pa.gov/filing-resources/tariffs/natural-gas-tariffs/. UGI Gas provides natural gas distribution service to approximately 672,000 residential, commercial and industrial natural gas customers located in 46 of Pennsylvania's total 67 counties and spanning more than 700 municipalities. The populations for each of the municipalities served, based on U.S. census data, is available at the Penn State Pennsylvania State Data Center website at: https://pasdc.hbg.psu.edu/Data/Census2010/tabid/1489/Default.aspx. UGI Gas also provides natural gas service to approximately 500 customers in one Maryland County under authority granted by the Maryland Public Service Commission.

UGI Electric can trace its origins to the 1925 acquisition by UGI of the American Gas Co., which owned the Luzerne County Gas and Electric Corporation. In 1953, as authorized by a Certificate of Public Convenience issued by the Commission on June 16, 1952, at Docket No. A.78264, all of UGI's Pennsylvania public utility subsidiaries, including the Luzerne County Gas and Electric Company, were merged into UGI. In 1967, UGI acquired the Harney's Lake Light Company, whose 113 square mile service territory, along with the electric service territory of the former Luzerne County Gas and Electric Corporation, comprise UGI Electric's current service territory. UGI Electric provides electric distribution service to approximately 62,000 residential, commercial, and industrial electric customers in Luzerne and Wyoming Counties and 35 municipalities.

I-A-2

Request:

Provide a schedule showing the measures of value and the rates of return at the original cost and trended original cost measures of value at the spot, three-year and five-year average price levels. All claims made on this exhibit should be cross-referenced to appropriate exhibits. Provide a schedule similar to the one listed above, reflecting respondent's final claim in its previous rate case.

Response:

The Company's claim is based on original cost measures of value. Since Pennsylvania state law mandates the use of original cost for ratemaking, a trended cost study was not prepared.

Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule A-1.

Refer to Attachment I-A-2 for similar schedules from the previous rate case.

Prepared by or under the supervision of: Christopher R. Brown

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2019
($ in Thousands)

Schedule A-1
Witness: S. F. Anzaldo
Page 1 of 1

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2019 At Present Rates	[4] Increase	[5] Proposed Rates
	RATE BASE					
1	Utility Plant		C-2	$ 3,620,724		$ 3,620,724
2	Accumulated Depreciation		C-3	(1,023,715)		(1,023,715)
3	Net Plant in service	L 1 + L 2		2,597,009	-	2,597,009
4	Working Capital		C-4	39,364		39,364
5	Gas Inventory		C-5	23,026		23,026
6	Accumulated Deferred Income Taxes		C-6	(569,005)		(569,005)
7	Customer Deposits		C-7	(22,290)		(22,290)
8	Materials & Supplies		C-8	14,601		14,601
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 2,082,705	$ -	$ 2,082,705
	OPERATING REVENUES AND EXPENSES					
	Operating Revenues					
10	Base Customer Charges		D-5	$ 540,891	$ 587	$ 541,478
11	Gas Cost Revenue		D-5	299,508		299,508
12	Other Operating Revenues		D-5	9,180		9,180
13	Total Revenues	Sum L 10 to L 12		849,579	587	850,166
14	Operating Expenses		D	(632,429)	(9)	(632,438)
15	OIBIT	L 13 + L 14		217,150	578	217,728
16	Pro Forma Income Tax at Present Rates		D-33	(46,780)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(167)	(46,946)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 170,371	$ 411	$ 170,782
19	RATE OF RETURN	L 18 / L 9		8.1803%		8.2000%
	REVENUE INCREASE REQUIRED					
20	Rate of Return at Present Rates	L 19, Col 3		8.1803%		
21	Rate of Return Required		B-7	8.2000%		
22	Change in ROR	L 21 - L 20		0.0197%		
23	Change in Operating Income	L 22 * L 9		$ 411		
24	Gross Revenue Conversion Factor		D-35	1.428398		
25	Change in Revenues	L 23 * L 24		$ 587		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, C 4			0.11%	
27	Percent Increase -- Total Revenues	L 25 / L 13, C 4			0.07%	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2020
($ in Thousands)

Schedule A-1
Witness: S. F. Anzaldo

Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2020 At Present Rates	[4] Increase	[5] Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 3,948,368		$ 3,948,368
2	Accumulated Depreciation		C-3	(1,085,297)		(1,085,297)
3	Net Plant in service	L 1 + L 2		2,863,071	-	2,863,071
4	Working Capital		C-4	40,988		40,988
5	Gas Inventory		C-5	23,026		23,026
6	Accumulated Deferred Income Taxes		C-6	(594,320)		(594,320)
7	Customer Deposits		C-7	(22,290)		(22,290)
8	Materials & Supplies		C-8	14,601		14,601
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 2,325,076	$ -	$ 2,325,076
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 574,694	$ 29,255	$ 603,949
11	Gas Cost Revenue		D-5	283,086		283,086
12	Other Operating Revenues		D-5	6,297		6,297
13	Total Revenues	Sum L 10 to L 12		864,077	29,255	893,332
14	Operating Expenses		D	(664,040)	(452)	(664,492)
15	OIBIT	L 13 + L 14		200,037	28,803	228,840
16	Pro Forma Income Tax at Present Rates		D-33	(33,582)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(8,321)	(41,903)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 166,455	$ 20,481	$ 186,937
19	RATE OF RETURN	L 18 / L 9		7.1591%		8.0400%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		7.1591%		
21	Rate of Return Required		B-7	8.0400%		
22	Change in ROR	L 21 - L 20		0.8809%		
23	Change in Operating Income	L 22 * L 9		$ 20,481		
24	Gross Revenue Conversion Factor		D-35	1.428398		
25	Change in Revenues	L 23 * L 24		$ 29,255		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, C 4			5.09%	
27	Percent Increase -- Total Revenues	L 25 / L 13, C 4			3.39%	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2021
($ in Thousands)

Schedule A-1
Witness: S. F. Anzaldo
Page 1 of 1

Summary of Measure of Value and Revenue Increase

		[1]	[2]	[3]	[4]	[5]
				Pro Forma Test Year Ended September 30, 2021 At		
Line #	Description	Function	Reference Section	Present Rates	Increase	Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 4,324,364		$ 4,324,364
2	Accumulated Depreciation		C-3	(1,160,183)		(1,160,183)
3	Net Plant in service	L 1 + L 2		3,164,181	-	3,164,181
4	Working Capital		C-4	42,331		42,331
5	Gas Inventory		C-5	23,026		23,026
6	Accumulated Deferred Income Taxes		C-6	(605,130)		(605,130)
7	Customer Deposits		C-7	(22,290)		(22,290)
8	Materials & Supplies		C-8	14,601		14,601
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 2,616,719	$ -	$ 2,616,719
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 582,003	$ 74,551	$ 656,554
11	Gas Cost Revenue		D-5	287,991		287,991
12	Other Operating Revenues		D-5	6,297		6,297
13	Total Revenues	Sum L 10 to L 12		876,291	74,551	950,842
14	Operating Expenses		D-1	(692,044)	(1,153)	(693,197)
15	OIBIT	L 13 + L 14		184,247	73,398	257,645
16	Pro Forma Income Tax at Present Rates		D-33	(28,410)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(21,207)	(49,616)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 155,837	$ 52,192	$ 208,029
19	RATE OF RETURN	L 18 / L 9		5.9554%		7.9500%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		5.9554%		
21	Rate of Return Required		B-7	7.9500%		
22	Change in ROR	L 21 - L 20		1.9946%		
23	Change in Operating Income	L 22 * L 9		$ 52,192		
24	Gross Revenue Conversion Factor		D-35	1.428398		
25	Change in Revenues	L 23 * L 24		$ 74,551		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, C 4			12.81%	
27	Percent Increase -- Total Revenues	L 25 / L 13, C 4			8.51%	

I-A-3

Request:

Provide a description of the depreciation methods utilized in calculating annual depreciation amounts and depreciation reserves, together with a discussion of all factors which were considered in arriving at estimates of service life and dispersion by account. Provide dates of all field inspections and facilities visited.

Response:

The depreciation methods used in calculating annual and accrued depreciation and the factors considered in service life estimation are discussed in Exhibit C (Future) in "Part II. Methods Used in the Determination of Annual and Accrued Depreciation" and Part III. Service Life Considerations". There have been no changes in the survivor curve estimates nor the method of depreciation. These are the same survivor curve estimates and method of depreciation as the prior gas base rate case filing in Docket R-2019-3015162.

Field trips and facilities visited are presented in Exhibit C (Future) in Part III in the section titled "Field Trips," beginning on page III-2.

Prepared by or under the supervision of: John F. Wiedmayer

I-A-4

Request:

Set forth, in exhibit form, charts depicting the original and estimated survivor curves and a tabular presentation of the original life table plotted on the chart for each account where the retirement rate method of analysis is utilized.

a. If any utility plant was excluded from the measures of value because it was deemed not to be "used and useful" in the public service, supply a detailed description of each item of property.

b. Provide the surviving original cost at test year end by vintage by account and include applicable depreciation reserves and annuities.

   (i) These calculations should be provided for plant in service as well as other categories of plant, including, but not limited, to contributions in aid of construction, customers' advances for construction, and anticipated retirements associated with any construction work in progress claims (if applicable).

Response:

Charts depicting the original and estimated survivor curves and a tabular presentation of the original life table plotted on the chart for each account where the retirement rate method of analysis was utilized is presented in Exhibit C (Future) in Part VI of the report.

a. No utility plant recorded in Account 101, Gas plant in Service, was excluded from the measures of value. However, gas plant owned by UGI Utilities, Inc. that serve approximately 500 Maryland customers in Frederick County, Maryland near the Pennsylvania-Maryland state border were excluded from this filing. The depreciation reserve and depreciation associated with Maryland gas plant also were excluded from this filing.

b. The surviving original cost at the end of the historical year September 30, 2021, by vintage by account and the applicable depreciation reserve for gas plant are presented in Exhibit C (Historic). The tabulations are presented in Part III of the report in the section titled "Depreciation Calculations."

I-A-4 (Continued)

The surviving original cost at the end of the future test year September 30, 2022, by vintage by account and the applicable depreciation reserve for gas plant are presented in Exhibit C (Future). The tabulations are presented in Part VII of the report in the section titled "Depreciation Calculations."

The surviving original cost at the end of the fully projected future test year September 30, 2023, by vintage by account and the applicable depreciation reserve for gas plant are presented in Exhibit C (Fully Projected). The tabulations are presented in Part III of the report in the section titled "Depreciation Calculations."

Prepared by or under the supervision of: John F. Wiedmayer

I-A-5

Request:

Provide a comparison of respondent's calculated depreciation reserve v. book reserve by account at the end of the test year.

Response:

Comparisons of the calculated accrued depreciation v. the book reserve are set forth in Attachment I-A-5.

Prepared by or under the supervision of: John F. Wiedmayer

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2021

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
GAS PLANT			
PRODUCTION PLANT			
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	100,374
325.2	PRODUCING LEASEHOLDS	152,969	162,069
325.4	RIGHTS-OF-WAY	23,166	29,681
328	FIELD MEASURING AND REGULATING STATION STRUCTURES	1,263	1,263
329	OTHER STRUCTURES	44,784	44,783
330	PRODUCING GAS WELLS - WELL CONSTRUCTION	18,208	18,209
331	PRODUCING GAS WELLS - WELL EQUIPMENT	24,442	24,441
332	FIELD LINES	422,567	724,840
334	FIELD MEASURING AND REGULATING STATION EQUIPMENT	48,477	84,547
335	DRILLING AND CLEANING EQUIPMENT	45,279	49,463
337	OTHER EQUIPMENT	11,062	11,062
TOTAL PRODUCTION PLANT		**792,217**	**1,250,732**
STORAGE PLANT			
352.01	WELL CONSTRUCTION	0	(51,904)
TOTAL STORAGE PLANT		**0**	**(51,904)**
TRANSMISSION PLANT			
365.2	RIGHTS-OF-WAY	514,665	525,023
366	STRUCTURES AND IMPROVEMENTS	127,104	145,020
367	MAINS	18,121,114	21,426,794
369	MEASURING AND REGULATING STATION EQUIPMENT	3,230,877	3,870,923
370	COMMUNICATION EQUIPMENT	1,627,017	2,030,369
371	OTHER EQUIPMENT	112,355	128,356
371.1	TESTING EQUIPMENT	142,490	147,396
TOTAL TRANSMISSION PLANT		**23,875,622**	**28,273,881**
DISTRIBUTION PLANT			
374.2	RIGHTS-OF-WAY	1,150,597	1,334,545
375	STRUCTURES AND IMPROVEMENTS	2,652,552	3,158,924
376.1	MAINS - PRIMARILY STEEL	174,431,489	175,899,219
376.2	MAINS - CAST IRON	1,705,295	268,125
376.3	MAINS - PLASTIC	260,931,499	274,291,463
376.5	MAINS - PRIMARILY WROUGHT IRON	261,387	276,113
376.7	REG AFUDC	132,209	134,963
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	26,080,708	26,330,599
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	7,563,156	7,762,976
380	SERVICES	365,285,679	367,843,768
381	METERS	52,222,848	52,248,571
381.1	METERS - ERTS	17,263,860	18,643,419
382	METER INSTALLATIONS	33,323,991	33,970,679
383	HOUSE REGULATORS	5,057,765	5,524,689
384	HOUSE REGULATOR INSTALLATIONS	7,441,873	8,437,825
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	14,585,215	16,636,654
386	OTHER PROPERTY ON CUSTOMERS PREMISES	36,346	(104,269)
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	566,726	648,577
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	22,545	24,720
387	OTHER EQUIPMENT	2,461,974	2,825,275
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,461,505	1,464,426
TOTAL DISTRIBUTION PLANT		**974,639,219**	**997,621,261**

UGI UTILITIES, INC. - GAS DIVISION

**COMPARISON OF CALCULATED ACCRUED DEPRECIATION
AND BOOK RESERVE AS OF SEPTEMBER 30, 2021**

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	35,887,089	39,865,784
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,186,935	800,633
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	56,396	35,807
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	732,420	653,878
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	4,378,297	4,336,112
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	535,124	666,930
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	5,167,221	5,971,127
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	864,299	882,856
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	1,136,288	1,315,349
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	564,914	644,625
393	STORES EQUIPMENT	5,436	5,453
394	TOOLS, SHOP AND GARAGE EQUIPMENT	12,115,907	11,576,680
395	LABORATORY EQUIPMENT	93,323	90,041
396	POWER OPERATED EQUIPMENT	1,827,492	1,924,973
397	COMMUNICATION EQUIPMENT	467,805	373,200
398	MISCELLANEOUS EQUIPMENT	1,220,206	649,081
399	OTHER TANGIBLE PROPERTY	16,032	16,032
TOTAL GENERAL PLANT		**66,255,184**	**69,808,561**
TOTAL DEPRECIABLE GAS PLANT		**1,065,562,242**	**1,096,902,531**
OTHER UTILITY PLANT*			
COMMON PLANT			
301	ORGANIZATION (NONDEPRECIABLE)	0	0
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	0	0
390.1	STRUCTURES AND IMPROVEMENTS	2,310,553	1,929,837
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY		10,628
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	928,374	780,636
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	354,490	213,695
392.1	TRANSPORTATION EQUIPMENT - CARS	65,227	71,637
398	MISCELLANEOUS EQUIPMENT	4,195	669
TOTAL COMMON PLANT		**3,662,839**	**3,007,102**
INFORMATION SERVICES (IS)			
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	33,772	33,595
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	13,203,200	12,938,845
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	2,999,625	1,464,953
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	19,742,596	18,682,455
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	39,910,084	39,050,337
TOTAL INFORMATION SERVICES		**75,889,277**	**72,170,185**
TOTAL OTHER UTILITY PLANT		**79,552,116**	**75,177,287**

*AMOUNTS SHOWN FOR OTHER UTILITY PLANT ARE PRIOR TO ALLOCATION.

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2022

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
GAS PLANT			
PRODUCTION PLANT			
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	92,158
325.2	PRODUCING LEASEHOLDS	153,496	162,102
325.4	RIGHTS-OF-WAY	23,364	29,699
328	FIELD MEASURING AND REGULATING STATION STRUCTURES	1,263	1,263
329	OTHER STRUCTURES	44,784	44,783
330	PRODUCING GAS WELLS - WELL CONSTRUCTION	18,208	18,209
331	PRODUCING GAS WELLS - WELL EQUIPMENT	24,442	24,441
332	FIELD LINES	426,614	725,816
334	FIELD MEASURING AND REGULATING STATION EQUIPMENT	49,355	84,969
335	DRILLING AND CLEANING EQUIPMENT	45,708	49,483
337	OTHER EQUIPMENT	11,062	11,062
TOTAL PRODUCTION PLANT		**798,296**	**1,243,985**
STORAGE PLANT			
352.01	WELL CONSTRUCTION	0	(35,934)
TOTAL STORAGE PLANT		**0**	**(35,934)**
TRANSMISSION PLANT			
365.2	RIGHTS-OF-WAY	524,565	536,830
366	STRUCTURES AND IMPROVEMENTS	129,204	146,334
367	MAINS	18,596,142	21,888,205
369	MEASURING AND REGULATING STATION EQUIPMENT	3,322,046	3,965,987
370	COMMUNICATION EQUIPMENT	1,721,813	2,140,531
371	OTHER EQUIPMENT	114,068	129,565
371.1	TESTING EQUIPMENT	147,789	152,562
TOTAL TRANSMISSION PLANT		**24,555,627**	**28,960,014**
DISTRIBUTION PLANT			
374.2	RIGHTS-OF-WAY	1,197,014	1,380,979
375	STRUCTURES AND IMPROVEMENTS	2,733,983	3,255,821
376.1	MAINS - PRIMARILY STEEL	182,958,013	186,259,998
376.2	MAINS - CAST IRON	1,441,920	17,698
376.3	MAINS - PLASTIC	280,626,275	290,557,616
376.5	MAINS - PRIMARILY WROUGHT IRON	249,721	243,917
376.7	REG AFUDC	396,626	398,720
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	27,887,083	26,618,827
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	8,115,185	8,409,477
380	SERVICES	391,077,964	396,104,279
381	METERS	54,906,726	55,211,410
381.1	METERS - ERTS	17,887,217	19,365,192
382	METER INSTALLATIONS	35,073,318	36,058,830
383	HOUSE REGULATORS	5,226,814	6,698,745
384	HOUSE REGULATOR INSTALLATIONS	7,770,913	8,896,752
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	15,368,431	17,515,028
386	OTHER PROPERTY ON CUSTOMERS PREMISES	37,395	(94,200)
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	580,438	663,828
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	22,782	24,705
387	OTHER EQUIPMENT	2,567,882	2,932,388
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,466,540	1,468,898
TOTAL DISTRIBUTION PLANT		**1,037,592,240**	**1,061,988,908**

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2022

ACCOUNT		CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
(1)		(2)	(3)
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	38,884,513	42,197,098
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,332,851	1,008,484
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	69,293	48,200
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	544,171	490,975
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	0	(42,186)
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	873,662	931,201
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	7,079,257	7,238,621
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	1,037,645	998,425
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	1,415,029	1,502,377
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	650,525	688,700
393	STORES EQUIPMENT	6,318	6,326
394	TOOLS, SHOP AND GARAGE EQUIPMENT	13,210,770	12,823,468
395	LABORATORY EQUIPMENT	115,211	112,149
396	POWER OPERATED EQUIPMENT	2,263,165	2,417,013
397	COMMUNICATION EQUIPMENT	482,894	401,771
398	MISCELLANEOUS EQUIPMENT	1,234,854	889,505
399	OTHER TANGIBLE PROPERTY	0	0
TOTAL GENERAL PLANT		**69,200,158**	**71,712,127**
TOTAL DEPRECIABLE GAS PLANT		**1,132,146,321**	**1,163,869,100**
OTHER UTILITY PLANT*			
COMMON PLANT			
301	ORGANIZATION (NONDEPRECIABLE)	0	0
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	0	0
390.1	STRUCTURES AND IMPROVEMENTS	3,168,852	2,943,559
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	0	0
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,146,765	1,014,315
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	596,714	516,102
392.1	TRANSPORTATION EQUIPMENT - CARS	66,459	71,637
398	MISCELLANEOUS EQUIPMENT	6,992	3,880
TOTAL COMMON PLANT		**4,985,782**	**4,549,493**
INFORMATION SERVICES (IS)			
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	28,752	28,532
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	12,822,771	12,323,496
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	4,199,490	2,950,328
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	11,334,932	10,614,784
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	43,333,019	42,466,804
TOTAL INFORMATION SERVICES		**71,718,964**	**68,383,944**
TOTAL OTHER UTILITY PLANT		**76,704,746**	**72,933,437**

*AMOUNTS SHOWN FOR OTHER UTILITY PLANT ARE PRIOR TO ALLOCATION.

UGI UTILITIES, INC. - GAS DIVISION

**COMPARISON OF CALCULATED ACCRUED DEPRECIATION
AND BOOK RESERVE AS OF SEPTEMBER 30, 2023**

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
GAS PLANT			
PRODUCTION PLANT			
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	69,118
325.2	PRODUCING LEASEHOLDS	153,961	162,135
325.4	RIGHTS-OF-WAY	23,572	29,717
328	FIELD MEASURING AND REGULATING STATION STRUCTURES	1,263	1,263
329	OTHER STRUCTURES	44,784	44,783
330	PRODUCING GAS WELLS - WELL CONSTRUCTION	18,208	18,209
331	PRODUCING GAS WELLS - WELL EQUIPMENT	24,442	24,441
332	FIELD LINES	430,575	726,792
334	FIELD MEASURING AND REGULATING STATION EQUIPMENT	50,261	85,373
335	DRILLING AND CLEANING EQUIPMENT	46,127	49,503
337	OTHER EQUIPMENT	11,062	11,062
TOTAL PRODUCTION PLANT		**804,255**	**1,222,396**
STORAGE PLANT			
352.01	WELL CONSTRUCTION	0	(35,934)
TOTAL STORAGE PLANT		**0**	**(35,934)**
TRANSMISSION PLANT			
365.2	RIGHTS-OF-WAY	534,302	548,463
366	STRUCTURES AND IMPROVEMENTS	130,987	147,551
367	MAINS	19,067,488	22,345,709
369	MEASURING AND REGULATING STATION EQUIPMENT	3,412,897	4,059,205
370	COMMUNICATION EQUIPMENT	1,812,740	2,244,418
371	OTHER EQUIPMENT	115,717	130,718
371.1	TESTING EQUIPMENT	152,800	157,623
TOTAL TRANSMISSION PLANT		**25,226,931**	**29,633,687**
DISTRIBUTION PLANT			
374.2	RIGHTS-OF-WAY	1,242,390	1,427,058
375	STRUCTURES AND IMPROVEMENTS	2,812,687	3,342,997
376.1	MAINS - PRIMARILY STEEL	191,449,358	196,479,099
376.2	MAINS - CAST IRON	1,173,596	(195,436)
376.3	MAINS - PLASTIC	303,764,730	309,834,305
376.5	MAINS - PRIMARILY WROUGHT IRON	237,990	217,498
376.7	REG AFUDC	661,044	662,477
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	31,357,470	28,860,503
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	8,642,593	9,033,447
380	SERVICES	418,142,543	425,136,757
381	METERS	57,991,662	58,594,291
381.1	METERS - ERTS	18,464,024	19,970,658
382	METER INSTALLATIONS	36,950,584	38,252,514
383	HOUSE REGULATORS	5,393,269	7,112,846
384	HOUSE REGULATOR INSTALLATIONS	8,098,070	9,351,213
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	16,132,073	18,366,647
386	OTHER PROPERTY ON CUSTOMERS PREMISES	38,381	(84,503)
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	593,776	678,603
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	23,000	24,705
387	OTHER EQUIPMENT	2,670,333	3,034,573
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,471,359	1,473,072
TOTAL DISTRIBUTION PLANT		**1,107,310,932**	**1,131,573,324**

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF CALCULATED ACCRUED DEPRECIATION AND BOOK RESERVE AS OF SEPTEMBER 30, 2023

	ACCOUNT	CALCULATED ACCRUED DEPRECIATION	BOOK RESERVE
	(1)	(2)	(3)
GENERAL PLANT			
390.1	STRUCTURES AND IMPROVEMENTS	41,954,408	44,037,136
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,504,592	1,234,708
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	86,937	65,601
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	43,755	(17,170)
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	0	(42,186)
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	1,325,434	1,327,881
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	9,706,311	9,350,144
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	1,249,307	1,181,222
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	1,755,935	1,790,761
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	769,842	772,421
393	STORES EQUIPMENT	7,197	7,199
394	TOOLS, SHOP AND GARAGE EQUIPMENT	14,506,746	14,190,646
395	LABORATORY EQUIPMENT	137,100	134,257
396	POWER OPERATED EQUIPMENT	2,673,695	2,887,895
397	COMMUNICATION EQUIPMENT	543,344	478,901
398	MISCELLANEOUS EQUIPMENT	1,344,499	1,187,196
399	OTHER TANGIBLE PROPERTY	0	0
TOTAL GENERAL PLANT		**77,609,102**	**78,586,612**
TOTAL DEPRECIABLE GAS PLANT		**1,210,951,220**	**1,240,980,085**
OTHER UTILITY PLANT*			
COMMON PLANT			
301	ORGANIZATION (NONDEPRECIABLE)	0	0
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	0	0
390.1	STRUCTURES AND IMPROVEMENTS	4,021,040	3,951,151
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	0	0
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,357,793	1,240,166
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	787,676	737,137
392.1	TRANSPORTATION EQUIPMENT - CARS	67,474	71,637
398	MISCELLANEOUS EQUIPMENT	9,789	7,091
TOTAL COMMON PLANT		**6,243,772**	**6,007,182**
INFORMATION SERVICES (IS)			
390.1	STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER	5,200	5,200
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	7,008	6,523
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	10,195,242	9,506,822
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	5,399,276	4,435,984
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	16,600,242	15,462,616
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	49,282,264	48,452,565
TOTAL INFORMATION SERVICES		**81,489,232**	**77,869,710**
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS - UNITE ADC	1,372,430	1,945,443
TOTAL OTHER UTILITY PLANT		**89,105,434**	**85,822,335**

*AMOUNTS SHOWN FOR OTHER UTILITY PLANT ARE PRIOR TO ALLOCATION.

I-A-6

Request:

Supply a schedule by account and depreciable group showing the survivor curve and annual accrual rate estimated to be appropriate:

a. For the purposes of this filing.

b. For the purposes of the most recent rate increase filing prior to the current proceedings.

(i) Supply a comprehensive statement of any changes made in method of depreciation and in the selection of average service lives and dispersion.

Response:

a. Refer to Table 1 in Exhibit C (Historic), Table 1 in Exhibit C (Future) and Table 1 in Exhibit C (Fully Projected) for schedules showing the estimated survivor curves and accrual rates by account and depreciable group.

b. Refer to Attachment I-A-6 for the survivor curves and annual accrual rates estimated to be appropriate in the most recent prior rate filing. UGI's most recent prior base rate case was filed in January 2020 at Docket No. R-2019-3015162.

(i). The depreciation methods and procedures used in this filing are the same as those used in the previous filing.

The survivor curve estimates are based on a service life study as described in Part III of Exhibit C (Future). The service life study was updated to include company data through fiscal-year end 2017, i.e., September 30, 2017. The service lives and survivor curves were used to calculate depreciation rates as of September 30, 2021, September 30, 2022 and September 30, 2023. The charts and life tables supporting the updated service life study are presented in Part VI of Exhibit C (Future).

The previous rate filing for UGI Gas was submitted in January 2020 using a fully projected future test year ending September 30, 2021. The service life study in the 2020 filing was based on data through September 30, 2017 which is the same as the current 2022 base rate case filing. The

I-A-6 (Continued)

Company updates its service life study every five years and submits a report to the Pennsylvania Public Utility Commission (PA PUC) in accordance with 52 Pa. Code Chapter 73.5 and 73.6. UGI submits Annual Depreciation Reports each year in accordance with 52 Pa. Code Chapter 73.3 and 73.4.

The purpose of the regulations set forth in 52 Pa. Code Chapter 73 is to establish uniform and industry-wide reporting requirements designed to improve the Commission's ability to monitor on a regular basis the depreciation and capital planning of utilities subject to Commission jurisdiction.

Prepared by or under the supervision of: John F. Wiedmayer

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2021

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
GAS PLANT								
PRODUCTION PLANT								
305	MANUFACTURED GAS PLANT SITE REMEDIATION		FULLY ACCRUED *	0	(14,821)	14,821	-	0
325.2	PRODUCING LEASEHOLDS		55 - S0.5	163,100	162,070	1,030	0.02	35
325.4	RIGHTS-OF-WAY		60 - R1	30,277	29,681	596	0.06	19
328	FIELD MEASURING AND REGULATING STATION STRUCTURES		FULLY ACCRUED	1,263	1,263	0	-	0
329	OTHER STRUCTURES		FULLY ACCRUED	44,785	44,783	2	-	0
330	PRODUCING GAS WELLS - WELL CONSTRUCTION		FULLY ACCRUED	18,209	18,210	(1)	-	0
331	PRODUCING GAS WELLS - WELL EQUIPMENT		FULLY ACCRUED	24,441	24,441	0	-	0
332	FIELD LINES		47 - L0	750,689	724,803	25,886	0.13	1,004
334	FIELD MEASURING AND REGULATING STATION EQUIPMENT		24 - O3	89,725	79,835	9,890	0.68	614
335	DRILLING AND CLEANING EQUIPMENT		30 - S0.5	49,604	49,461	143	0.04	19
337	OTHER EQUIPMENT		FULLY ACCRUED	11,062	11,062	0	-	0
TOTAL PRODUCTION PLANT				**1,183,155**	**1,130,788**	**52,367**	**0.14**	**1,691**
STORAGE PLANT								
352.01	WELL CONSTRUCTION		FULLY ACCRUED *	0	(19,964)	19,964	-	0
TOTAL STORAGE PLANT				**0**	**(19,964)**	**19,964**	-	**0**
TRANSMISSION PLANT								
365.2	RIGHTS-OF-WAY		70 - R4	868,160	524,589	343,571	1.37	11,864
366	STRUCTURES AND IMPROVEMENTS		30 - R1	248,104	152,465	95,639	2.37	5,869
367	MAINS		70 - R3	38,518,031	21,416,849	17,101,182	1.17	450,280
369	MEASURING AND REGULATING STATION EQUIPMENT		49 - R2	6,170,122	3,869,009	2,301,113	1.53	94,608
370	COMMUNICATION EQUIPMENT		23 - R0.5	3,486,136	2,017,296	1,468,840	3.19	111,341
371	OTHER EQUIPMENT		35 - R2.5	140,637	128,216	12,421	0.88	1,232
371.1	TESTING EQUIPMENT		20 - R3	210,011	147,017	62,994	2.50	5,258
TOTAL TRANSMISSION PLANT				**49,641,201**	**28,255,441**	**21,385,760**	**1.37**	**680,452**
DISTRIBUTION PLANT								
374.2	RIGHTS-OF-WAY		75 - R3	3,345,151	1,331,872	2,013,279	1.29	43,109
375	STRUCTURES AND IMPROVEMENTS		50 - S0.5	5,325,825	3,175,277	2,150,548	1.55	82,425
376.1	MAINS - PRIMARILY STEEL		73 - R2.5	666,558,235	178,973,692	487,584,543	1.55	10,298,871
376.2	MAINS - CAST IRON	09-2027	65 - R1	2,120,235	1,607,538	512,697	4.38	92,836
376.3	MAINS - PLASTIC		67 - R3	1,394,503,742	272,754,820	1,121,748,922	1.65	22,959,642
376.5	MAINS - PRIMARILY WROUGHT IRON	09-2041	70 - R1	277,777	249,701	28,076	0.98	2,728
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		47 - S0	135,082,679	22,757,386	112,325,293	3.00	4,049,874
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		45 - R2	20,526,673	7,624,620	12,902,053	2.34	479,346
380	SERVICES		46 - S1	1,210,144,530	375,032,798	835,111,732	2.45	29,686,611
381	METERS		35 - R2	135,363,595	53,567,652	81,795,943	3.05	4,126,059
381.1	METERS - ERTS		17 - S3	24,795,395	18,587,662	6,207,733	3.47	860,676
382	METER INSTALLATIONS		46 - S1	103,822,867	34,632,496	69,190,371	2.40	2,491,094
383	HOUSE REGULATORS		46 - S1	10,031,117	5,383,231	4,647,886	2.07	207,150
384	HOUSE REGULATOR INSTALLATIONS		46 - S1	20,129,279	8,538,172	11,591,107	2.11	424,135
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		45 - R2	35,423,963	16,561,456	18,862,507	2.02	716,158
386	OTHER PROPERTY ON CUSTOMERS PREMISES		46 - S1	337,967	162,947	175,020	2.14	7,236
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS		45 - R2	953,218	648,053	305,165	1.60	15,260
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS		25 - R3	24,705	24,435	270	0.32	80
386.3	OTHER PROPERTY ON CUSTOMER PREMISES - CNG REFUELING STATION			0	2,459	(2,459)	-	0

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2021

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
387	OTHER EQUIPMENT		35 - R2.5	4,694,731	2,822,326	1,872,405	2.12	99,344
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE		25 - SQ	1,490,664	1,464,426	26,238	0.30	4,400
TOTAL DISTRIBUTION PLANT				**3,774,952,348**	**1,005,903,019**	**2,769,049,329**	**2.03**	**76,647,034**
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS		VARIOUS**	118,970,668	39,334,613	79,636,055	4.08	4,850,432
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY		FULLY ACCRUED	85,127	85,127	0	-	0
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	9,368,117	1,891,024	7,477,093	4.96	464,597
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		10 - SQ	381,972	150,664	231,308	9.21	35,184
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT		5 - SQ	941,444	699,201	242,243	15.12	142,305
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S		8 - L2.5	2,794,893	791,523	2,003,370	14.10	394,153
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS		10 - L2.5	11,471,719	3,185,999	8,285,720	11.35	1,301,842
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES		12 - L3	9,927,448	1,277,563	8,649,885	9.49	942,535
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS		12 - L3	4,738,700	1,088,599	3,650,101	9.00	426,717
392.5	TRANSPORTATION EQUIPMENT - TRAILERS		15 - L2	1,220,000	492,049	727,951	6.74	82,230
392.6	TRANSPORTATION EQUIPMENT - CAPITAL LEASES			2,311,284	1,501,131	810,153		1,592,799
393	STORES EQUIPMENT		20 - SQ	17,606	5,346	12,260	5.03	885
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	33,238,792	11,502,644	21,736,148	5.40	1,793,913
395	LABORATORY EQUIPMENT		20 - SQ	437,779	90,041	347,738	5.05	22,099
396	POWER OPERATED EQUIPMENT		15 - L2	6,616,454	1,607,992	5,008,462	7.98	527,732
397	COMMUNICATION EQUIPMENT		10 - SQ	908,753	374,065	534,688	11.24	102,110
398	MISCELLANEOUS EQUIPMENT		15 - SQ	9,639,006	1,813,601	7,825,405	6.54	630,032
TOTAL GENERAL PLANT				**213,069,762**	**65,891,182**	**147,178,580**	**6.25**	**13,309,565**
TOTAL DEPRECIABLE GAS PLANT				**4,038,846,466**	**1,101,160,466**	**2,937,686,000**	**2.24**	**90,638,742**
NONDEPRECIABLE PLANT								
301	ORGANIZATION			166,477				
302	FRANCHISES AND CONSENTS			193,597				
303	MISCELLANEOUS INTANGIBLE PLANT			289,868				
304.1	LAND AND LAND RIGHTS - LAND			375,198				
304.2	LAND AND LAND RIGHTS - LAND RIGHTS			6,454				
325.1	PRODUCING LANDS			13,029				
325.5	OTHER LAND			1,134				
365.1	LAND			47,323				
374.1	LAND AND LAND RIGHTS - LAND			849,347				
374.2	LAND AND LAND RIGHTS - LAND RIGHTS			7,094,605				
389.1	LAND AND LAND RIGHTS - LAND			3,273,828				
389.2	LAND AND LAND RIGHTS - LAND RIGHTS			1,313				
TOTAL NONDEPRECIABLE PLANT				**12,312,173**				
TOTAL GAS PLANT				**4,051,158,639**				

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2021

ACCOUNT (1)	PROBABLE RETIREMENT YEAR (2)	SURVIVOR CURVE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE BOOK ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL RATE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)
OTHER UTILITY PLANT							
COMMON PLANT							
301 ORGANIZATION (NONDEPRECIABLE)			138,964				
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108				
390.1 STRUCTURES AND IMPROVEMENTS	01-2069	70 - R1	29,899,361	2,551,321	27,348,040	2.90	868,169
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	1,056,425	423,817	632,608	6.20	65,535
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	139,971	122,703	17,268	8.22	11,512
392.1 TRANSPORTATION EQUIPMENT - CARS		7 - L2.5	71,637	70,952	685	0.49	351
TOTAL COMMON PLANT			**38,253,466**	**3,168,793**	**27,998,601**	**2.48**	**945,567**
TOTAL COMMON PLANT ALLOCATED TO ALL GAS DIVISIONS - 88.43%			**33,827,540**	**2,802,164**	**24,759,162**		**836,165**
INFORMATION SERVICES (IS)							
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	36,837	33,590	3,247	4.88	1,796
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	17,035,480	10,967,724	6,067,756	19.05	3,244,980
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	09-2025	SQUARE	2,803,866	0	2,803,866	25.00	700,966
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	48,271,125	10,856,600	37,414,525	9.89	4,774,407
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	188,415,910	39,102,010	149,313,900	6.88	12,969,290
TOTAL INFORMATION SERVICES			**256,563,218**	**60,959,924**	**195,603,294**	**8.45**	**21,691,439**
TOTAL INFORMATION SERVICES ALLOCATED TO ALL GAS DIVISIONS - 94.12%			**241,477,301**	**57,375,480**	**184,101,820**		**20,415,982**
READING SERVICE CENTER							
390.1 STRUCTURES AND IMPROVEMENTS	06-2030	80 - R1.5	2,060,918	1,452,050	608,868	3.46	71,221
LESS READING SERVICE CENTER ALLOCATED TO ELECTRIC DIVISION - 9.35%			**192,696**	**135,766**	**56,929**		**6,659**
EMPIRE YARD BUILDING							
390.1 STRUCTURES AND IMPROVEMENTS	12-2047	80 - R1.5	14,623,728	7,817,467	6,806,261	3.06	447,414
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.04%			**1,906,934**	**1,019,398**	**887,536**		**58,343**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ALL GAS DIVISIONS			**273,205,211**	**59,022,480**	**207,916,517**		**21,187,145**
TOTAL PLANT IN SERVICE			**4,324,363,850**	**1,160,182,946**	**3,145,602,517**		**111,825,887**
AMORTIZATION OF NEGATIVE NET SALVAGE							*7,851,440*
GRAND TOTAL			**4,324,363,850**	**1,160,182,946**	**3,145,602,517**		**119,677,327**

* ACCOUNTS 305 AND 352.01 HAVE NO REMAINING DEPRECIATION ACCRUALS. THE FUTURE ACCRUALS SHOWN ARE RELATED TO THE AMORTIZATION OF NEGATIVE NET SALVAGE.
** SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES.INDIVIDUAL BUILDINGS ARE LIFE SPANNED.
*** CAPITAL LEASE AMOUNTS SHOWN IN ACCOUNT 392.6 ARE CALCULATED IN THE COMPANY'S CAPITAL LEASE AMORTIZATION SCHEDULES.

I-A-7

Request:

Provide a table, showing the cumulative depreciated original cost by year of installation for utility plant in service at the end of the test year (depreciable plant only) as claimed in the measures of value, in the following form:

a. Year installed.

b. Original cost--the total surviving cost associated with each installation year from all plant accounts.

c. Calculated depreciation reserve--the calculated depreciation reserve associated with each installation year from all plant accounts.

d. Depreciated original cost--(Column B minus Column C).

e. Total--cumulation year by year of the figures from Column D.

f. Column E divided by the total of the figure in Column D.

Response:

The information is provided in Exhibit C (Fully Projected) in Part III for the fully projected future test year ended September 30, 2023; in Exhibit C (Future) in Part V for the future test year ended September 30, 2022; and in Exhibit C (Historic) in Part III for the historic test year ended September 30, 2021. The information is set forth in the section titled “Cumulative Depreciated Original Cost.”

Prepared by or under the supervision of: John F. Wiedmayer

I-A-8

Request:

Provide a description of the trending methodology which was utilized. Identify all indexes which were used (include all backup workpapers) and the reasons particular indexes were chosen. If indexes were spliced, indicate which years were utilized in any splices. If indexes were composited, show all supporting calculations. Include any analysis made to "test" the applicability of any indexes.

a. Supply a comprehensive statement of any changes made in the selection of trend factors or in the methodology used in the current rate filing compared to the most recent previous rate filing.

Response:

Trended original cost is omitted in accordance with 52 Pa. Code Section 53.51(c).

Prepared by or under the supervision of: John F. Wiedmayer

I-A-9

Request:

Provide an exhibit indicating the spot trended original cost at test year end by vintage by account and include applicable depreciation reserves. Include totals by account for all other trended measures of value.

Response:

Trended original cost is omitted in accordance with 52 Pa. Code Section 53.51(c).

Prepared by or under the supervision of: John F. Wiedmayer

I-A-10

Request:

Supply an exhibit indicating the percentages of undepreciated original cost which were trended with the following indexes:

a. Boeckh
b. Handy-Whitman
c. Indexes developed from suppliers' prices.
d. Indexes developed from company records and company price histories.
e. Construction equipment.
f. Government statistical releases.

Response:

Trended original cost is omitted in accordance with 52 Pa. Code Section 53.51(c).

Prepared by or under the supervision of: John F. Wiedmayer

I-A-11

Request:

Provide a table, showing the cumulative trended depreciated original cost (at the spot price level) by year of installation for utility plant in service at the end of the test year (depreciable plant only) as claimed in the measures of value, in the following form:

a. Year installed.

b. Trended original cost (at the spot price level)--the total surviving cost associated with each installation year from all plant accounts.

c. Trended calculated depreciation reserve--the calculated depreciation reserve associated with each installation year from all plant accounts.

d. Depreciated trended original cost--(Column B minus Column C).

e. Total--cumulation year by year of the figures from Column D.

f. Column E divided by the total of the figures in Column D.

Response:

Trended original cost is omitted in accordance with 52 Pa. Code Section 53.51(c).

Prepared by or under the supervision of: John F. Wiedmayer

I-A-12

Request:

If a claim is made for construction work in progress, include, in the form of an exhibit, the summary page from all work orders, amount expended at the end of the test year and anticipated in-service dates. Indicate if any of the construction work in progress will result in insurance recoveries, reimbursements, or retirements of existing facilities. Describe in exact detail the necessity of each project claimed if not detailed on the summary page from the work order. Include final completion date and estimated total amounts to be spent on each project.

[These exhibits should be updated at the conclusion of these proceedings.]

Response:

No claim is being made for construction work in progress.

Prepared by or under the supervision of: Vivian K. Ressler

I-A-13

Request:

If a claim is made for non-revenue producing construction work in progress, include, in the form of an exhibit, the summary page from all work orders, amount expended at the end of the test year and anticipated in-service dates. Indicate if any of the construction work in progress will result in insurance recoveries, reimbursements, or retirements of existing facilities. Describe in exact detail the necessity of each project claimed if not detailed on the summary page from the work order. Include final completion date and estimated total amounts to be spent on each project.

[These exhibits should be updated at the conclusion of these proceedings.]

Response:

No claim is being made for non-revenue producing construction work in progress.

Prepared by or under the supervision of: Vivian K. Ressler

I-A-14

Request:

If a claim is made for plant held for future use, supply the following

a. A brief description of the plant or land site and its cost.

b. Expected date of use for each item claimed.

c. Explanation as to why it is necessary to acquire each item in advance of its date of use.

d. Date when each item was acquired.

e. Date when each item was placed in plant held for future use.

Response:

No claim is being made for plant held for future use.

Prepared by or under the supervision of: Vivian K. Ressler

I-A-15

Request:

If materials and supplies comprise part of the cash working capital claim, attach an exhibit showing the actual book balances for materials and supplies by month for the thirteen months prior to the end of the test year. Explain any abrupt changes in monthly balances.

[Explain method of determining claim if other than that described above.]

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-8.

Prepared by or under the supervision of: Vivian K. Ressler

I-A-16

Request:

If fuel stocks comprise part of the cash working capital claim, provide an exhibit showing the actual book balances (quantity and price) for the fuel inventories by type of fuel for the thirteen months prior to the end of the test year by location, station, etc.

[Explain the method of determining claim if other than that described above.]

Response:

Please refer to Attachment SDR-RR-45. The fuel represents gas inventory stored underground.

Prepared by or under the supervision of: Vivian K. Ressler

I-A-17

Request:

Regardless of whether a claim for net negative or positive salvage is made, attach an exhibit showing gross salvage, cost of removal, and net salvage for the test year and four previous years by account.

Response:

The information related to the historic test year is presented in Part IV of Exhibit C (Historic) in the section titled “Experienced Net Salvage.” The information related to the future test year is set forth in Part VIII of Exhibit C (Future) in the section titled “Experienced and Estimated Net Salvage.” The information related to the fully projected future test year is set forth in Part IV of Exhibit C (Fully Projected) in the section titled “Experienced and Estimated Net Salvage.”

Prepared by or under the supervision of: John F. Wiedmayer

I-A-18

Request:

Explain in detail by statement or exhibit the appropriateness of claiming any additional items, not previously mentioned, in the measures of value.

Response:

All measures of value have been fully disclosed in UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedules A-1 and C-1 through C-8, as well as the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 3.

Prepared by or under the supervision of: Vivian K. Ressler

I-C-1

Request:

Provide, with respect to the scope of operations of the utility, a description of all property, including an explanation of the system's operation, and all plans for any significant future expansion, modification, or other alteration of facilities.

This description should include, but not be limited to the following:

a. If respondent has various gas service areas, indicate if they are integrated, such that the gas supply is available to all customers.

b. Provide all pertinent data regarding company policy related to the addition of new consumers in the company's service area.

c. Explain how respondent obtains its gas supply, as follows:

    (i) Explain how respondent stores or manufactures gas; if applicable.

    (ii) State whether the company has peak shaving facilities.

    (iii) Provide details of coal-gasification programs, if any.

    (iv) Describe the potential for emergency purchases of gas.

    (v) Provide the amount of gas in MCF supplied by various suppliers in the test year (include a copy of all contracts).

    (vi) Provide the amount of gas in MCF supplied from company-owned wells during the test year.

d. Provide plans for future gas supply, as follows:

    (i) Supply details of anticipated gas supply from respondent's near-term development of gas wells, if any.

    (ii) Provide gas supply agreements and well development ventures and identify the parties thereto.

I-C-1 (Continued)

e. Indicate any anticipated curtailments and explain the reasons for the curtailments.

f. Provide current data on any Federal Power Commission action or programs that may affect, or tend to affect, the natural gas supply to the gas utility.

Response:

a. UGI's gas system consists of approximately 12,000 miles of distribution main and approximately 300 miles of transmission lines served primarily from 84 city gate stations or interconnections with interstate pipelines and one significant gathering system. The distribution system served approximately 672,000 customers as of September 30, 2021. Ninety percent of the customers are residential.

UGI Gas distributes natural gas to areas across Pennsylvania lying within the Counties of Adams, Armstrong, Bedford, Berks, Blair, Bradford, Bucks, Carbon, Centre, Chester, Clarion, Clearfield, Clinton, Columbia, Cumberland, Dauphin, Forest, Franklin, Fulton, Huntingdon, Jefferson, Juniata, Lackawanna, Lancaster, Lebanon, Lehigh, Luzerne, Lycoming, McKean, Mifflin, Monroe, Montour, Montgomery, Northampton, Northumberland, Pike, Potter, Schuylkill, Snyder, Susquehanna, Tioga, Union, Vernango, Wayne, Wyoming, and York.

UGI Gas distribution systems are fed directly by eight interstate pipelines, Tennessee Gas Pipeline Company ("Tennessee"), Columbia Gas Transmission ("Columbia"), Transcontinental Gas Pipe Line Company, LLC. ("Transco"), Texas Eastern Transmission, LP (“Texas Eastern”), UGI Sunbury, LLC (“Sunbury”), UGI Mt. Bethel Pipeline Company, LLC (“Mt. Bethel”), Eastern Gas Transmission and Storage ("EGTS"), and UGI Storage Company (“UGI Storage”). Some distribution systems are fed by multiple pipelines and others are isolated feeds. It is expected that Adelphia Gateway ("Adelphia") will also provide supply into the UGI Gas distribution system beginning in January 2022.

b. UGI Gas pursues the addition of new and expanded load in the residential, commercial, and industrial market areas. UGI Gas follows its tariff guidelines in obtaining these additions.

UGI Gas’ tariff guidelines define the rate schedule the customer can utilize, the investment UGI Gas makes to obtain the customer and all other aspects of the Company’s business.

I-C-1 (Continued)

Beyond the tariff provisions, the other controlling factors in obtaining new load would be the availability from interstate pipelines, gas supply, and capacity on the UGI Gas distribution system.

All customer additions are administered through the Marketing Department. All new customer requests are in the form of a gas application. Once the application has been reviewed for distribution system adequacy, credit and cost, an approval letter is sent to the customer. If a new meter, service or main is required, the work is also scheduled at the time of approval.

c. (i) UGI Gas does not manufacture gas. UGI Gas has no gas storage facilities.

(ii) UGI Gas has no peak shaving facilities.

(iii) UGI Gas has no coal gasification programs.

(iv) UGI Gas does not anticipate the purchase of emergency gas.

(v) Please see Attachment III-E-36 which provides the purchases made from various producers from October 2020 through September 2021. The producer names have been replaced with alphabetic letters for confidentiality reasons. The purchases are typically made under the provision of a standard GISB or NAESB contract. Most contracts have special provisions adding language that may not have been contemplated when the GISB or NAESB contracts were first deployed.

(vi) Not applicable. UGI Gas does not own any gas wells.

d. (i) UGI Gas does not anticipate any development of company-owned gas wells.

(ii) UGI Gas does not have well development ventures. UGI Gas' gas supply arrangements are detailed in its annual Purchased Gas Cost filings, the most recent of which was docketed at R-2021-3025652.

e. UGI Gas does not anticipate curtailments for the system.

f. UGI Gas monitors FERC activity and evaluates pending impacts to rate payers. The FERC proceedings in which UGI Gas intervened are provided in the 1307(f)

I-C-1 (Continued)

Purchased Gas Cost filings for 2021 in Book 1, Section 3 at Docket No. R-2021-3025652.

Prepared by or under the supervision of: Christopher R. Brown

I-C-2

Request:

Provide an overall system map, including and labeling all measuring and regulating stations, storage facilities, production facilities, transmission and distribution mains, by size, and all interconnections with other utilities and pipelines.

Response:

In light of the security concerns reflected in the Commission's Workplace Security Survey at Docket No. M-00021590, UGI Gas has not included system maps in this filing.

Prepared by or under the supervision of: Christopher R. Brown

SECTION 53.53 – RATE OF RETURN

II-A-1

Request:

Provide capitalization and capitalization ratios for the last five-year period and projected through the next two years. (With short-term debt and without short-term debt.) (Company, Parent and System (consolidated)).

a. Provide year-end interest coverages before and after taxes for the last three years and at latest date. (Indenture and SEC Bases.) (Company, Parent and System (consolidated)).

b. Provide year-end preferred stock dividend coverages for last three years and at latest date (Charter and SEC bases).

Response:

Please see Attachment II-A-1.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc.
CAPITALIZATION RATIOS (Millions)

Consolidated - UGI Corporation - With Short-Term Debt

	9/30/2017 Actual	%	9/30/2018 Actual	%	9/30/2019 Actual	%	9/30/2020 Actual	%	9/30/2021 Actual	%	9/30/2022 Budget	%	9/30/2023 Budget	%
Common Equity	$3,163.3	38.2	$3,681.4	42.4	$3,817.5	36.7	$4,128.0	39.2	$5,309.0	43.0				
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	213.0	1.7				
Minority Interests	577.6	7.0	418.6	4.8	9.7	0.1	9.0	0.1	9.0	0.1				
Short-Term Debt	366.9	4.4	424.9	4.9	796.3	7.7	347.0	3.3	367.0	3.0				
Long-Term Debt	4,172.1	50.4	4,165.3	47.9	5,779.9	55.6	6,034.0	57.4	6,449.0	52.2				
Total Capitalization	$8,279.9	100.0	$8,690.2	100.0	$10,403.4	100.0	$10,518.0	100.0	$12,347.0	100.0	$0.0	0.0	$0.0	0.0

Consolidated - UGI Corporation - Without Short-Term Debt

	9/30/2017 Actual	%	9/30/2018 Actual	%	9/30/2019 Actual	%	9/30/2020 Actual	%	9/30/2021 Actual	%	9/30/2022 Budget	%	9/30/2023 Budget	%
Common Equity	$3,163.3	40.0	$3,681.4	44.5	$3,817.5	39.7	$4,128.0	40.6	$5,309.0	44.3				
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	213.0	1.8				
Minority Interests	577.6	7.3	418.6	5.1	9.7	0.1	9.0	0.1	9.0	0.1				
Long-Term Debt	4,172.1	52.7	4,165.3	50.4	5,779.9	60.2	6,034.0	59.3	6,449.0	53.8				
Total Capitalization	$7,913.0	100.0	$8,265.3	100.0	$9,607.1	100.0	$10,171.0	100.0	$11,980.0	100.0	$0.0	0.0	$0.0	0.0

Company Only - UGI Utilities, Inc. - With Short-Term Debt

	9/30/2017 Actual	%	9/30/2018 Actual	%	9/30/2019 Actual	%	9/30/2020 Actual	%	9/30/2021 Actual	%	9/30/2022 Budget	%	9/30/2023 Budget	%
Common Equity	$ 1,014.7	57.5	$ 1,113.6	55.9	$ 1,228.3	55.1	$ 1,314.0	52.5	$ 1,424.9	50.8	$ 1,635.3	53.0	$ 1,822.3	55.1
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	0.0	0.0
Short-Term Debt	0.0	0.0	47.3	2.4	25.9	1.2	69.2	2.8	93.2	3.3	44.4	1.4	0.0	0.0
Long-Term Debt	751.1	42.5	831.2	41.7	974.5	43.7	1,117.8	44.7	1,285.9	45.9	1,405.0	45.5	1,483.8	44.9
Total Capitalization	$ 1,765.8	100.0	$ 1,992.1	100.0	$ 2,228.7	100.0	$ 2,500.9	100.0	$ 2,804.0	100.0	$ 3,084.8	100.0	$ 3,306.0	100.0

Company Only - UGI Utilities, Inc. - Without Short-Term Debt

	9/30/2017 Actual	%	9/30/2018 Actual	%	9/30/2019 Actual	%	9/30/2020 Actual	%	9/30/2021 Actual	%	9/30/2022 Budget	%	9/30/2023 Budget	%
Common Equity	$ 1,014.7	57.5	$ 1,113.6	57.3	$ 1,228.3	55.8	$ 1,314.0	54.0	$ 1,424.9	52.6	$ 1,635.3	53.8	$ 1,822.3	55.1
Preferred Stock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long-Term Debt	751.1	42.5	831.2	42.7	974.5	44.2	1,117.8	46.0	1,285.9	47.4	1,405.0	46.2	1,483.8	44.9
Total Capitalization	$ 1,765.8	100.0	$ 1,944.8	100.0	$ 2,202.8	100.0	$ 2,431.8	100.0	$ 2,710.8	100.0	$ 3,040.3	100.0	$ 3,306.0	100.0

UGI Utilities, Inc.
INTEREST COVERAGE RATIO

Consolidated - UGI Corporation

	9/30/2018	9/30/2019	9/30/2020	9/30/2021
Pre-tax interest coverage	4.71	2.55	3.07	7.42
Post-tax interest coverage	4.61	2.43	2.85	5.99

Consolidated - UGI Utilities, Inc.

	9/30/2018	9/30/2019	9/30/2020	9/30/2021
Pre-tax interest coverage	5.54	4.55	4.20	4.42
Post-tax interest coverage	4.71	3.93	3.72	3.86

II-A-2

Request:

Provide latest quarterly financial report (Company and Parent).

Response:

A copy of the Company's latest quarterly financial report as of September 30, 2021 can be found at https://www.ugicorp.com/static-files/3dd9789e-fd43-4096-b99f-0faacdab6ac5.

Please refer to II-A-3 for the latest quarterly financial report of UGI Corporation as of September 30, 2021.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-3

Request:

Provide latest Stockholder's Report (Company and Parent).

Response:

UGI Utilities, Inc. does not produce an annual Stockholder's Report.

Please refer to the SEC website for a copy of UGI Corporation's latest Stockholder's Report on form 10-K. This can be found at https://www.sec.gov/ix?doc=/Archives/edgar/data/0000884614/000088461421000065/ugi-20210930.htm.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-4

Request:

Provide latest Prospectus (Company and Parent).

Response:

Please see the following link for the Prospectus Supplement from UGI Utilities Senior Notes Offering dated 9/24/08 for the latest UGI Utilities Prospectus: https://www.sec.gov/Archives/edgar/data/100548/000119312508201953/d424b2.htm.

Please see the following link for the latest UGI Corporation prospectus dated 6/12/19: https://www.sec.gov/Archives/edgar/data/0000884614/000119312519193147/d693774d424b3.htm.

See the response to II-A-19 for additional information regarding this UGI Corporation prospectus.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-5

Request:

Supply projected capital requirements and sources of Company, Parent and System (consolidated) for each of future three years.

Response:

See Attachment II-A-5 for projected capital expenditure requirements for Fiscal Years ending September 30, 2022, and September 30, 2023. The sources of funds may be internally generated, from contributions from parent, or from outside financing as needed.

The projection for Fiscal Year 2024 is confidential and will be made available to parties upon request and the entry of an acceptable Protective Order.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
PROJECTED CAPITAL EXPENDITURES
FOR THE YEARS ENDED SEPTEMBER 30, 2022 AND 2023
(millions of dollars)

	2022	2023
Consolidated UGI Utilities, Inc. (including Electric Division)	$ 475.0	$ 499.0
UGI Utilities, Inc. - Gas Division	$ 452.5	$ 469.8

II-A-6

Request:

Provide a schedule of debt and preferred stock of Company, Parent and System (consolidated) as of test year-end and latest date, detailing for each issue (if applicable):

a. Date of issue
b. Date of maturity
c. Amount issued
d. Amount outstanding
e. Amount retired
f. Amount reacquired
g. Gain on reacquisition
h. Coupon rate
i. Discount or premium at issuance
j. Issuance expenses
k. Net proceeds
l. Sinking Fund requirements
m. Effective interest rate
n. Dividend rate
o. Effective cost rate
p. Total average weighted effective Cost Rate

Response:

Please refer to pages 11 through 14 of UGI Gas Exhibit B for this data.

Prepared by or under the supervision of: Paul R. Moul

II-A-7

Request:

Supply financial data of Company and/or Parent for last five years:

a. Earnings-price ratio (average)
b. Earnings-book value ratio (per share basis) (avg. book value)
c. Dividend yield (average)
d. Earnings per share (dollars)
e. Dividends per share (dollars)
f. Average book value per share yearly
g. Average yearly market price per share (monthly high-low basis)
h. Pre-tax funded debt interest coverage
i. Post-tax funded debt interest coverage
j. Market price-book value ratio

Response:

Please refer to Attachment II-A-7 for the requested financial data of UGI Corporation. UGI Utilities, Inc. has no publicly traded shares outstanding.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Corporation
Select Financial Data
For the Year Ended September 30,

	2017	2018	2019	2020	2021
Income Statement Data *(millions)* :					
Revenues	$ 6,121	$ 7,651	$ 7,320	$ 6,559	$ 7,447
Operating Income	$ 1,010	$ 1,065	$ 617	$ 982	$ 2,350
Net Income attributable to UGI Corporation	$ 437	$ 719	$ 256	$ 532	$ 1,467
Common Stock data:					
Market price at year end	$ 46.86	$ 55.48	$ 50.27	$ 32.98	$ 42.62
Average yearly market price per share	$ 47.70	$ 48.76	$ 53.33	$ 36.82	$ 41.09
Book value per share (at year end)	$ 18.18	$ 21.14	$ 18.24	$ 19.70	$ 26.31
Earnings per share (diluted)	$ 2.46	$ 4.06	$ 1.41	$ 2.54	$ 6.92
Dividends declared per share	$ 0.98	$ 1.02	$ 1.15	$ 1.31	$ 1.35
Dividend rate per share (at year end)	$ 0.97	$ 1.02	$ 0.95	$ 1.30	$ 1.34
Ratios:					
Earnings-price ratio	19.0	13.7	35.7	13.0	6.2
Earnings-book value ratio	7.4	5.2	12.9	7.8	3.8
Dividend yield - average	2.1%	2.1%	2.1%	3.6%	3.3%
Pre-tax funded debt interest coverage	4.1	4.7	2.6	3.1	7.4
Post-tax funded debt interest coverage	3.6	4.6	2.4	2.9	6.0
Market price / Book value ratio	2.6	2.6	2.8	1.7	1.6

II-A-8

Request:

State amount of debt interest utilized for income tax calculations, and details of debt interest computations, under each of the following rate case bases:

a. Actual test year

b. Annualized test year-end

c. Proposed test year-end

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule D-33. All external debt is held at the UGI Utilities, Inc. level. For ratemaking purposes, interest expense is synchronized to the Measure of Value funded at the claimed capital structure and cost of debt.

Prepared by or under the supervision of: Nicole M. McKinney

II-A-9

Request:

State amount of debt interest utilized for income tax calculations which has been allocated from the debt interest of an affiliate, and details of the allocation, under each of the following rate case bases:

a. Actual test year

b. Annualized test year-end

c. Proposed test year-end

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule D-33. All external debt is held at the UGI Utilities, Inc. level. For ratemaking purposes, interest expense is synchronized to the Measure of Value funded at the claimed capital structure and cost of debt.

Prepared by or under the supervision of: Nicole M. McKinney

II-A-10

Request:

Under Section 1552 of the Internal Revenue Code and Regulations 1.1552-1 thereunder, if applicable, Parent Company, in filing a consolidated income tax return for the group, must choose one of four options by which it must allocate total income tax liability of the group to the participating members to determine each member's tax liability to the federal government. (If this interrogatory is not applicable, so state.)

a. State what option has been chosen by the group.

b. Provide, in summary form, the amount of tax liability that has been allocated to each of the participating members in the consolidated income tax return.

c. Provide a schedule, in summary form, of contributions, which were determined on the basis of separate tax return calculations, made by each of the participating members to the tax liability indicated in the consolidated group tax return. Provide total amounts of actual payments to the tax depository for the tax year, as computed on the basis of separate returns of members.

d. Provide annual income tax return for group, and if income tax return shows net operating loss, provide details of amount of net operating loss allocated to the income tax returns of each of the members of the consolidated group.

Response:

a. UGI Corporation has elected to allocate the tax liability of the consolidated group to the members in accordance with Regulation 1.1502-33 (d)(2)(ii). Further, the group elects to use 100 percent as the percentage specified in Regulation 1.1502-33(d)(2)(ii)(b). This method of allocation is to be applied in conjunction with the basic allocation method provided in Regulation 1.1552-1(a)(2). UGI Corporation also elected to reflect currently the investment adjustment in earnings and profits pursuant to Regulation 1.1502-33(c)(4)(iii).

b. & c. See Attachment II-A-10.

d. See SDR-RR-55 for copies of certain pages of the 9/30/20 UGI Consolidated Federal Income Tax Return.

II-A-10 (Continued)

The tax results for the year ended 9/30/20 reflect a net operating loss. See Attachment II-A-10 for the allocation of the net operating loss among the consolidated group.

Prepared by or under the supervision of: Nicole M. McKinney

UGI Utilities, Inc. - Gas Division
Allocation of UGI Corporation Consolidated Federal Income Tax Liability
For the Year Ended September 30, 2020
(thousands of dollars)

	(a)	(b)	(c)	(d)	(e)
Name of Company	**Federal Taxable Income**	**Federal Income Tax @ 21.00% Allocated**	**Foreign Tax Credit**	**General Business Credit**	**Col (b) + Col (c) - Col (d) = Net Federal Income Tax Liability**
AmeriGas Inc	(23)	(5)			0
AmeriGas Propane Inc.	56,320	11,827			0
AmeriGas Propane Holdings, Inc.	(207,170)	(43,506)			0
Amerigas Technology Group Inc.	0	0			0
Ashtola Production Company	(1)	(0)			0
Eastfield International Holdings Inc	0	0			0
Energy Service Funding	3,479	731			0
EuroGas Holdings Inc.	0	0			0
Four Flags Drilling Company	0	0			0
Hellertown Pipeline	0	0			0
Homestead Holding	(607)	(128)			0
Newberry Holding	955	201			0
UGI Asset Management	0	0			0
UGI Black Sea Enterprises	0	0			0
UGI China Inc	0	0			0
UGI Corporation	(201,320)	(42,277)			0
UGI Development Company	(16,858)	(3,540)			0
UGI Energy Ventures, Inc.	0	0			0
UGI Ethanol Development Company	0	0			0
UGI Europe Inc	22,795	4,787			0
UGI Hunlock Dev	0	0			0
UGI HVAC Enterprises	4,824	1,013			0
UGI International China. Inc	0	0			0
UGI International (Romania)	0	0			0
UGI LNG	2,318	487			0
UGI Penn HVAC Services	0	0			0
UGI Petroleum Products of DE	0	0			0
UGI Properties, Inc.	349	73			0
UGI Romania, Inc.	0	0			0
UGI Storage Company	4,152	872			0
UGI Utilities, Inc.	73,276	15,388			0
UGID Holding Company	(8)	(2)			0
United Valley Insurance	323	68			0
Eliminations	0	0			0
Adjustments	2,180	458			0
Total Taxable	**(255,015)**	**(53,553)**	**0**	**0**	**0**

II-A-11

Request:

Provide AFUDC charged by company at test year-end and latest date, and explain method by which rate was calculated.

Response:

AFUDC totaling $438,051 was recorded during the historic test year. UGI Gas follows the FERC guidance for calculation of the AFUDC rate. The calculated rate for the historic test year of 1.01% was based on average construction work in process compared to short-term borrowings on a monthly basis and on an aggregated annual basis. UGI Gas is currently using the short-term debt rate for AFUDC because the average short-term borrowing balances exceeds the average construction work in process balance.

The projected short-term debt rates for the future test year (Fiscal Year 2022) and fully projected test year (Fiscal Year 2023) are 1.01% and 1.30%, respectively.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-12

Request:

Set forth provisions of Company's and Parent's charter and indentures (if applicable) which describe coverage requirements, limits on proportions of types of capital outstanding, and restrictions on dividend payouts.

Response:

UGI Utilities, Inc. entered into an unsecured revolving credit agreement in June 2019 ("Revolving Credit Agreement") with a group of banks that provides for a loan commitment of up to $350 million. UGI Utilities, Inc. may request a $150 million increase in the amount of loan commitments under the Revolving Credit Agreement to a maximum aggregate of $500 million. Under the Revolving Credit Agreement, UGI Utilities, Inc. may borrow at various prevailing interest rates, including LIBOR and the banks' prime rate, plus a margin. The margin on such borrowings ranges from 0.0% to 1.75% and is based on the credit ratings of certain indebtedness of UGI Utilities, Inc.

UGI Utilities, Inc. has various issuances of Senior Notes due at various times from June 2026 through April 2050. The Senior Notes are unsecured.

UGI Utilities, Inc. has a $125 million variable rate Term Loan, with principal payments of $1,562,500 due quarterly and the remaining principal due October 2022. Under this Note, UGI Utilities, Inc. may borrow at various prevailing market interest rates, plus an applicable margin.

The Revolving Credit Agreement, certain of the Senior Notes, and the Term Loan require UGI Utilities, Inc. not to exceed a ratio of Consolidated Debt to Consolidated Total Capital, as defined, of 0.65 to 1.00. Additionally, certain of the Senior Notes require that Consolidated Priority Debt not exceed 10% of Consolidated Total Assets.

Please refer to UGI Gas Exhibit B for a description of all other Notes which do not have defined coverage requirements, (other than that expressed above) limits on types of capital outstanding, or restrictions on dividend payouts.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-13

Request:

Attach copies of the summaries of the projected 2 year's Company's budgets (revenue, expense and capital).

Response:

Please see Attachment II-A-13 for the Company's 2022 and 2023 operating budget and plan. For capital budgets, please refer to the response to II-A-5.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Projected Company Budget
Twelve Months Ending September 30,
(Thousands of Dollars)

	2022	2023
Operating Revenues:		
Operating Revenues	$ 991,527	$ 986,747
Other Operating Revenues	9,891	9,939
Total Operating Revenues	1,001,418	996,686
Operating Expenses:		
Gas Production	14	14
Gas Supply Production	346,127	358,286
Distribution	79,926	84,369
Customer Accounts	51,842	54,960
Customer Service and Information	10,220	10,368
Sales	1,638	1,725
Administrative and General	110,015	116,044
Depreciation and Amortization	117,066	128,358
Taxes, Other than Income Taxes	12,964	13,360
Total Operating Expenses	729,812	767,484
Operating Income	$ 271,606	$ 229,202

II-A-14

Request:

Describe long-term debt reacquisitions by Company and Parent as follows:

a. Reacquisitions by issue by year.

b. Total gain on reacquisitions by issue by year.

c. Accounting of gain for income tax and book purposes.

Response:

The Company and its Parent have not reacquired any debt in more than twenty years.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-15

Request:

Set forth amount of compensating bank balances required under each of the following rate base bases:

a. Annualized test year operations.

b. Operations under proposed rates.

Response:

Not Applicable. UGI Utilities, Inc. has no compensating bank balance requirements.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-16

Request:

Provide the following information concerning compensating bank balance requirements for actual test year:

a. Name of each bank.

b. Address of each bank.

c. Types of accounts with each bank (checking, savings, escrow, other services, etc.).

d. Average Daily Balance in each account.

e. Amount and percentage requirements for compensating bank balance at each bank.

f. Average daily compensating bank balance at each bank.

g. Documents from each bank explaining compensating bank balance requirements.

h. Interest earned on each type of account.

Response:

Not Applicable. UGI Utilities, Inc. has no compensating bank balance requirements.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-17

Request:

Provide the following information concerning bank notes payable for actual test year:

a. Line of Credit at each bank.

b. Average daily balances of notes payable to each bank, by name of bank.

c. Interest rate charged on each bank note (Prime rate, formula rate or other).

d. Purpose of each bank note (e.g., construction, fuel storage, working capital, debt retirement).

e. Prospective future need for this type of financing.

Response:

a. In June 2019, the Company entered into a five-year $350 million revolving credit facility with a consortium of banks (“2019 RCF”). The 2019 RCF is currently scheduled to expire in June 2024. Please see Attachment II-A-17 for the commitment from each bank.

b. The 2019 RCF is predominantly used to meet working capital needs and is more heavily utilized in the Fall and Winter months when inventory and receivables balances peak. The borrowings from each bank are pro rata as per their respective commitments. The average daily borrowing under the Company’s 2019 RCF was $186.2 million for fiscal year 2021.

c. The interest rates for the majority of borrowings under the Company’s 2019 RCF are under the LIBOR + Applicable Margin formula. The Applicable Margin is based on public credit ratings as specified on Attachment II-A-17. The Company has two public debt ratings (Moody’s and Fitch). When there is a split rating, the Moody’s rating applies unless such ratings differ by two or more levels. If ratings differ by two or more levels, the applicable level will be deemed to be one level below the higher of such levels. Based on current ratings of the Company, the applicable margins are 0.875%.

II-A-17 (Continued)

d. The borrowings under the 2019 RCF are for working capital needs, CWIP, and general corporate purposes.

e. The 2019 RCF provides adequate liquidity for working capital needs, CWIP, and general corporate purposes and does not mature until June 2024.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
Line of Credit Bank Commitments and Applicable Margin
As of September 30, 2021

Lender Commitments of the UGI Gas five year, $350 million revolving credit facility:

Lender	Commitment
PNC Bank, National Association	$75,000,000
Citizens Bank, N.A.	$75,000,000
Credit Suisse AG, Cayman Islands Branch	$40,000,000
JPMorgan Chase Bank, N.A.	$40,000,000
Wells Fargo Bank, National Association	$40,000,000
Bank of America, N.A.	$40,000,000
The Bank of New York Mellon	$40,000,000
	$350,000,000

Applicable Margin of the UGI Gas five year, $350 million revolving credit facility:

Debt Rating	Margin
A/A2/A	0.875%
A-/A3/A-	1.00%
BBB+/Baa1/BBB+	1.125%
BBB/Baa2/BBB	1.25%
BBB-/Baa3/BBB-	1.50%
BB+/Ba1/BB+	1.75%

II-A-18

Request:

Set forth amount of total cash (all cash accounts) on hand from balance sheets for last 24-calendar months preceding test year-end.

Response:

The average balance sheet cash (measured at the end of each month) for the past 24 calendar months (10/31/19 - 9/30/21) was $13.9 million.

Please see Attachment II-A-18.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
MONTH-END CASH BALANCES

Fiscal Year 2020		Balance Sheet Cash
October	$	5,374,487
November	$	7,938,841
December	$	7,791,645
January	$	8,181,282
February	$	5,791,875
March	$	3,980,701
April	$	123,321,409
May	$	99,008,847
June	$	4,156,584
July	$	2,138,543
August	$	1,880,009
September	$	4,926,257

Fiscal Year 2021		Balance Sheet Cash
October	$	1,553,239
November	$	6,088,589
December	$	9,329,795
January	$	14,096,738
February	$	7,187,955
March	$	5,992,399
April	$	3,030,010
May	$	1,310,319
June	$	1,834,643
July	$	851,045
August	$	5,728,686
September	$	1,070,010
Two-Year Average	**$**	**13,856,830**

II-A-19

Request:

Submit details on Company or Parent common stock offerings (past 5 years to present) as follows:

a. Date of Prospectus
b. Date of offering
c. Record date
d. Offering period--dates and number of days
e. Amount and number of shares of offering
f. Offering ratio (if rights offering)
g. Per cent subscribed
h. Offering price
i. Gross proceeds per share
j. Expenses per share
k. Net proceeds per share (i-j)
l. Market price per share
    1. At record date
    2. At offering date
    3. One month after close of offering
m. Average market price during offering
    1. Price per share
    2. Rights per share--average value of rights
n. Latest reported earnings per share at time of offering
o. Latest reported dividends at time of offering

Response:

The Company has not issued stock in the last five years.

The Parent has issued stock related to the below transaction. The below is an excerpt from the UGI Corporation ("UGI") 10-K filed 11/26/2019. The Common Units discussed in this excerpt represent AmeriGas partnership units.

"On August 21, 2019, the AmeriGas Merger was completed in accordance with the terms of the Merger Agreement entered into on April 1, 2019. Under the terms of the Merger Agreement, the Partnership was merged with and into Merger Sub, with the Partnership surviving as an indirect wholly owned subsidiary of UGI. Each outstanding Common

II-A-19 (Continued)

Unit other than the Common Units owned by UGI was automatically converted at the effective time of the AmeriGas Merger into the right to receive, at the election of each holder of such Common Units, one of the following forms of merger consideration (subject to proration designed to ensure the number of shares of UGI Common Stock issued would equal approximately 34.6 million):

(i) 0.6378 shares of UGI Common Stock (the “Share Multiplier”);

(ii) $7.63 in cash, without interest, and 0.500 shares of UGI Common Stock; or

(iii) $35.325 in cash, without interest.

Pursuant to the terms of the Merger Agreement, effective on August 21, 2019, we issued 34,612,847 shares of UGI Common Stock and paid $528.9 million in cash to the holders of Common Units other than UGI, for a total implied consideration of $2,227.7 million. In addition, the incentive distribution rights in the Partnership previously owned by the General Partner were canceled. After-tax transaction costs directly attributable to the transaction that were incurred by UGI totaling $7.7 million were recorded as a reduction to UGI stockholders’ equity. Transaction costs incurred by the Partnership totaling $6.3 million are reflected in “Operating and administrative expenses” on the 2019 Consolidated Statement of Income. The tax effects of the AmeriGas Merger resulting from the step-up in tax bases of the underlying assets resulted in the recording of a deferred tax asset in the amount of $512.3 million. This deferred tax asset is included in 'Deferred income taxes' on the September 30, 2019 Consolidated Balance Sheet.

Effective upon completion of the AmeriGas Merger, Common Units are no longer publicly traded."

Based on the above transaction, please see below:

a. Date of Prospectus: 7/12/2019
b. Date of offering: 8/21/2019
c. Record date: 8/21/2019
d. Offering period--dates and number of days: 40
e. Amount and number of shares of offering: 34,612,847
f. Offering ratio (if rights offering): N/A
g. Per cent subscribed: N/A
h. Offering price: N/A
i. Gross proceeds per share: N/A

II-A-19 (Continued)

j. Expenses per share: N/A
k. Net proceeds per share (i-j): N/A
l. Market price per share
    1. At record date: $49.08
    2. At offering date: $49.08
    3. One month after close of offering: $50.29
m. Average market price during offering
    1. Price per share: $49.80
    2. Rights per share--average value of rights: N/A
n. Latest reported earnings per share at time of offering: $1.90
    Basic EPS / GAAP / Twelve Months Ended June 30, 2019
o. Latest reported dividends at time of offering: $0.325 per share

On May 25, 2021, the Company's parent issued 2.2 million Equity Units with a total notional value of $220 million. The Equity Units are equity-linked securities and not common stock. Therefore, the Company has determined not to include the Equity Units in the answer to this request.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-20

Request:

Provide latest available balance sheet and income statement for Company, Parent and System (consolidated).

Response:

Please refer to UGI Gas Exhibit A (Historic), Schedules B-1 and B-2 for balance sheet and income statement of UGI Utilities, Inc. - Gas Division.

Please see the UGI Utilities, Inc. balance sheet and income statement as of 9/30/21 at Attachment II-A-20.

Also, please see UGI Corporation Report on Form 10-K for the year ended 9/30/21 at https://www.sec.gov/ix?doc=/Archives/edgar/data/0000884614/000088461421000065/ugi-20210930.htm for Parent Company financial statements

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Millions of dollars)

	September 30, 2021	September 30, 2020
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1	$ 5
Accounts receivable (less allowances for doubtful accounts of $16 and $15, respectively)	80	75
Accounts receivable — related parties	3	3
Accrued utility revenues	8	14
Inventories	57	39
Derivative instruments	21	7
Other current assets	32	21
Total current assets	202	164
Property, plant and equipment	4,620	4,265
Less accumulated depreciation	(1,288)	(1,210)
Net property, plant and equipment	3,332	3,055
Goodwill	182	182
Regulatory assets	337	395
Other assets	16	13
Total assets	$ 4,069	$ 3,809
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 7	$ 8
Short-term borrowings	130	141
Accounts payable — trade	82	86
Accounts payable — related parties	16	6
Employee compensation and benefits accrued	19	20
Interest accrued	13	13
Customer deposits and advances	42	40
Regulatory liabilities	39	38
Other current liabilities	54	39
Total current liabilities	402	391
Long-term debt	1,280	1,113
Deferred income taxes	510	462
Pension benefit obligations	88	170
Regulatory liabilities	313	315
Other noncurrent liabilities	73	77
Total liabilities	2,666	2,528
Common stockholder's equity:		
Common stock	60	60
Additional paid-in capital	474	474
Retained earnings	891	780
Accumulated other comprehensive loss	(22)	(33)
Total common stockholder's equity	1,403	1,281
Total liabilities and stockholder's equity	$ 4,069	$ 3,809

See accompanying Notes to Consolidated Financial Statements.

UGI UTILITIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Millions of dollars)

	Year Ended September 30,	
	2021	2020
Revenues	$ 1,070	$ 1,030
Costs and expenses:		
Cost of sales — gas and purchased power (excluding depreciation shown below)	456	448
Operating and administrative expenses	232	230
Operating and administrative expenses — related parties	21	15
Depreciation	118	105
Other operating expense, net	1	3
	828	801
Operating income	242	229
Pension and other postretirement plans non-service income	2	—
Interest expense	(55)	(54)
Income before income taxes	189	175
Income tax expense	(43)	(39)
Net income	$ 146	$ 136

See accompanying Notes to Consolidated Financial Statements.

II-A-21

Request:

Provide Original Cost, Trended Original Cost and Fair Value rate base claims.

Response:

The Company's claim is based on original cost measure of value. As Pennsylvania law requires use of original cost measure of value for ratemaking, trended original cost and fair value rate base claims were not prepared.

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-1.

Prepared by or under the supervision of: Vivian K. Ressler

II-A-22

Request:

a. Provide Operating Income claims under:

(i) Present rates
(ii) Pro forma present rates (annualized & normalized)
(iii) Proposed rates (annualized & normalized)

b. Provide Rate of Return on Original Cost and Fair Value claims under:

(i) Present rates
(ii) Pro forma present rates
(iii) Proposed rates

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedules A-1, D-1, and D-2.

Prepared by or under the supervision of: Tracy A. Hazenstab

II-A-23

Request:

List details and sources of “Other Property and Investment,” “Temporary Cash Investments” and “Working Funds” on test year-end balance sheet.

Response:

Please refer to the following responses:

Other Property and Investment - III-A-2

Temporary Cash Investments - III-A-3

Working Funds other than general operating cash - III-A-3

Prepared by or under the supervision of: Vivian K. Ressler

II-A-24

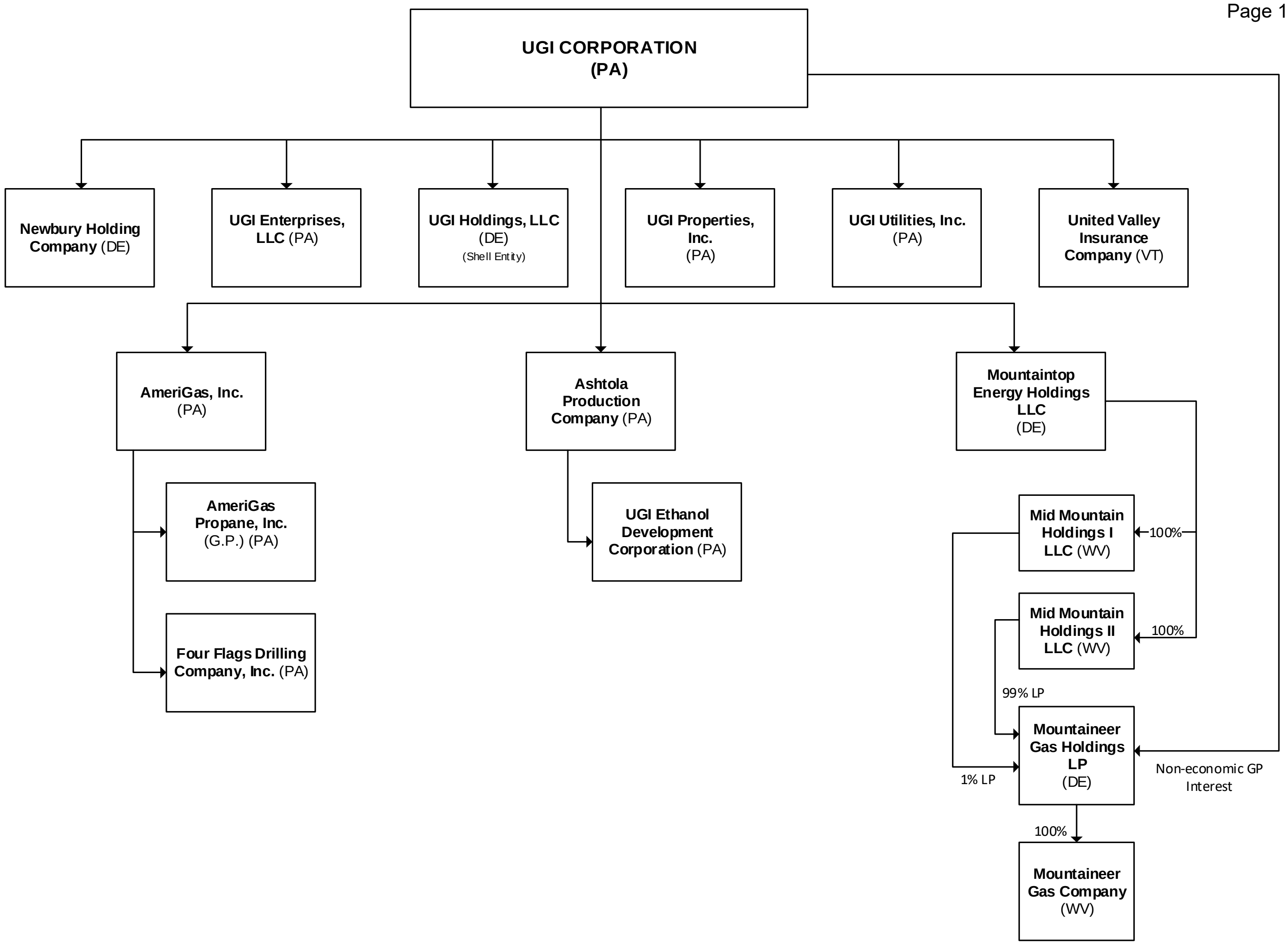
Request:

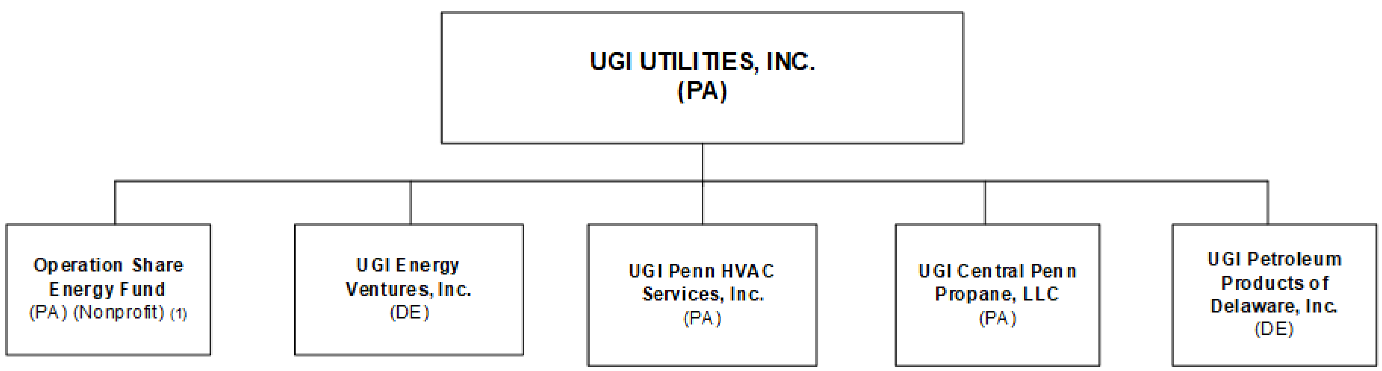
Attach chart explaining Company's corporate relationship to its affiliates (System Structure).

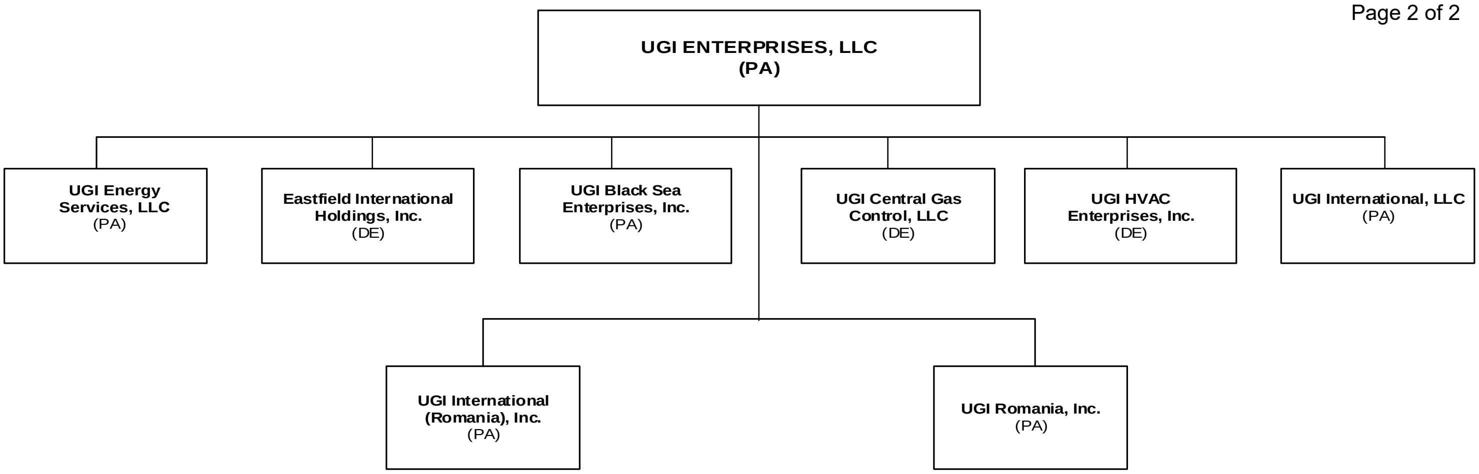
Response:

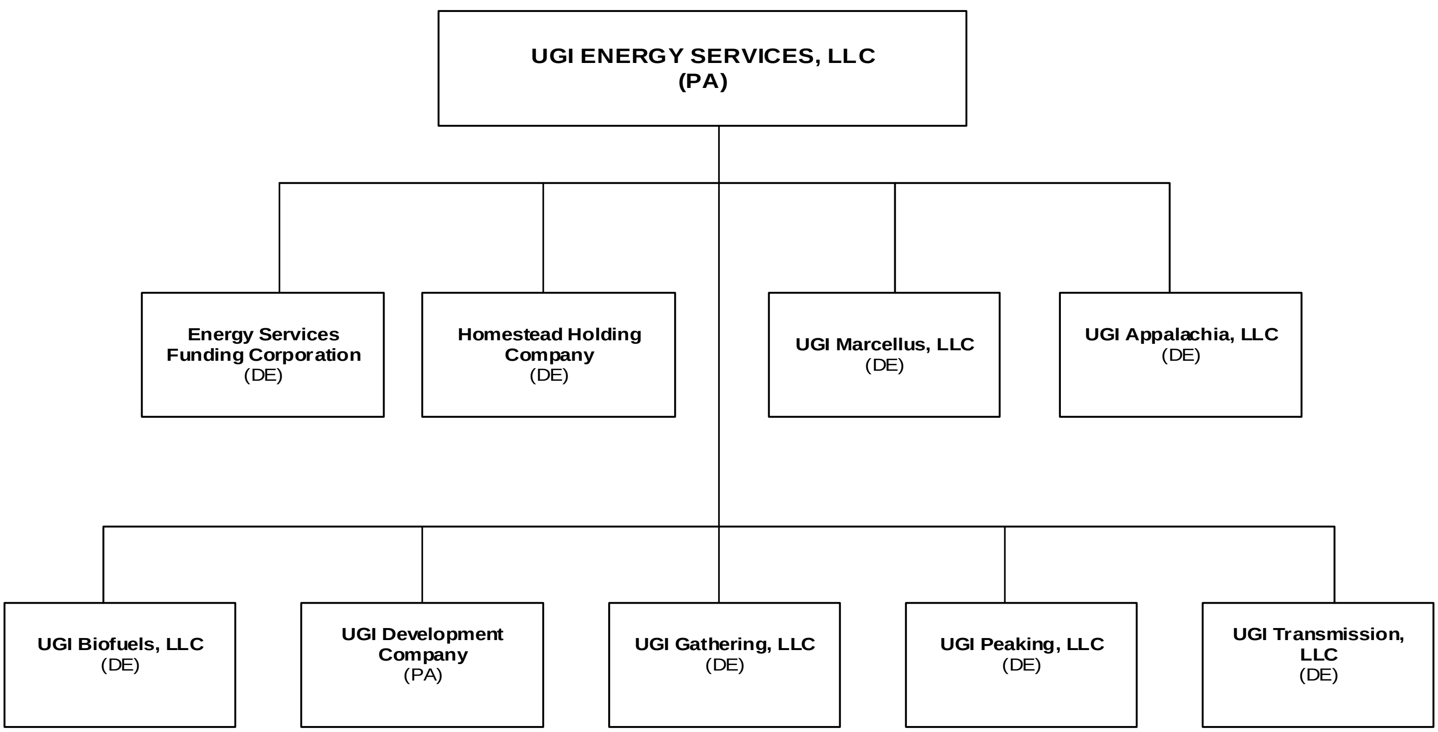
Please see Attachment II-A-24.

Prepared by or under the supervision of: Vivian K. Ressler


UGI CORPORATION
(PA)
Newbury Holding Company (DE)
UGI Enterprises, LLC (PA)
UGI Holdings, LLC (DE) (Shell Entity)
UGI Properties, Inc. (PA)
UGI Utilities, Inc. (PA)
United Valley Insurance Company (VT)
AmeriGas, Inc. (PA)
Ashtola Production Company (PA)
Mountaintop Energy Holdings LLC (DE)
AmeriGas Propane, Inc. (G.P.) (PA)
Four Flags Drilling Company, Inc. (PA)
UGI Ethanol Development Corporation (PA)
Mid Mountain Holdings I LLC (WV)
100%
Mid Mountain Holdings II LLC (WV)
100%
99% LP
Mountaineer Gas Holdings LP (DE)
1% LP
Non-economic GP Interest
100%
Mountaineer Gas Company (WV)


UGI UTILITIES, INC.
(PA)
Operation Share Energy Fund (PA) (Nonprofit) (1)
UGI Energy Ventures, Inc. (DE)
UGI Penn HVAC Services, Inc. (PA)
UGI Central Penn Propane, LLC (PA)
UGI Petroleum Products of Delaware, Inc. (DE)


UGI ENTERPRISES, LLC
(PA)
UGI Energy Services, LLC
(PA)
Eastfield International Holdings, Inc.
(DE)
UGI Black Sea Enterprises, Inc.
(PA)
UGI Central Gas Control, LLC
(DE)
UGI HVAC Enterprises, Inc.
(DE)
UGI International, LLC
(PA)
UGI International (Romania), Inc.
(PA)
UGI Romania, Inc.
(PA)


UGI ENERGY SERVICES, LLC
(PA)
Energy Services Funding Corporation
(DE)
Homestead Holding Company
(DE)
UGI Marcellus, LLC
(DE)
UGI Appalachia, LLC
(DE)
UGI Biofuels, LLC
(DE)
UGI Development Company
(PA)
UGI Gathering, LLC
(DE)
UGI Peaking, LLC
(DE)
UGI Transmission, LLC
(DE)

II-A-25

Request:

If the utility plans to make a formal claim for a specific allowable rate of return, provide the following data in statement or exhibit form:

a. Claimed capitalization and capitalization ratios with supporting data.
b. Claimed cost of long-term debt with supporting data.
c. Claimed cost of short-term debt with supporting data.
d. Claimed cost of total debt with supporting data.
e. Claimed cost of preferred stock with supporting data.
f. Claimed cost of common equity with supporting data.

Response:

a. Please see the Direct Testimony of Paul R. Moul, UGI Gas Statement No. 6, Exhibit B, Schedule 1.

b. Please see the Direct Testimony of Paul R. Moul, UGI Gas Statement No. 6, Exhibit B, Schedule 1.

c. No claim is being made for short-term debt.

d. Please see the Direct Testimony of Paul R. Moul, UGI Gas Statement No. 6, Exhibit B, Schedule 1.

e. This subparagraph is not applicable as the Company does not have preferred stock.

f. Please see the Direct Testimony of Paul R. Moul, UGI Gas Statement No. 6, Exhibit B, Schedule 1.

Prepared by or under the supervision of: Paul R. Moul

II-A-26

Request:

Provide the following income tax data:

a. Consolidated income tax adjustments, if applicable.

b. Interest for tax purposes (basis).

Response:

a. Please see Attachment II-A-26 for a calculation of a consolidated tax adjustment.

A consolidated tax adjustment has not been flowed through as a ratemaking deduction in the calculation of UGI Gas's federal income tax expense. This adjustment has only been included to demonstrate that UGI Gas has fulfilled the requirements of Section 1301.1(b) of Act 40. Please see the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, for a discussion on how the Company has satisfied these requirements.

b. The interest tax deduction for rate making purposes is synchronized with interest component of the capital structure.

Prepared by or under the supervision of: Nicole M. McKinney

UGI Utilities, Inc. - Gas Division
Calculation of Consolidated Tax Adjustment
For the Years Ended September 30, 2018, 2019 and 2020
(thousands of dollars)

	Taxable Income 2018	Taxable Income 2019	Taxable Income 2020	Average	% of Total	CTA
Tax Loss Entities						
Ashtola Production Company	(1)	(1)	(1)	(1)		
Homestead Holding	(155)	(273)	(607)	(345)		
UGI Hunlock Dev	(90)	0	0	(30)		
UGI HVAC Enterprises	(893)	(305)	0	(399)		
UGID Holding Company	(7)	(8)	(8)	(8)		
United Valley Insurance	(239)	(751)	0	(330)		
UGI Corporation	0	0	(147,867)	(49,289)		
AmeriGas Inc	(26)	(26)	(23)	(25)		
AmeriGas Propane Holdings, Inc.	0	0	0	0		
UGI Penn HVAC Services	(16)	0	0	(5)		
UGI Properties, Inc.	(99)	0	0	(33)		
UGI Utilities, Inc.	0	0	0	0		
UGI Enterprises Inc	0	0	0	0		
UGI Development Company	0	(5,924)	(4,961)	(3,628)		
Subtotal Taxable Loss	(1,525)	(7,286)	(153,467)	(54,093)		
Tax Positive Entities						
AmeriGas Propane Inc.	61,224	93,880	56,320	70,475	39.9%	(21,601)
AmeriGas Inc.	0	0	0	0	0.0%	0
AmeriGas Propane Holdings, Inc.	0	90	3,842	1,311	0.7%	(402)
Amerigas Technology Group Inc.	0	0	0	0	0.0%	0
Energy Service Funding	4,782	5,062	3,479	4,441	2.5%	(1,361)
Newberry Holding	2,660	3,253	955	2,290	1.3%	(702)
Petrolane Incorporated	0	0	0	0	0.0%	0
UGI China, Inc.	0	0	0	0	0.0%	0
UGI Corporation	27,142	37,610	0	21,584	12.2%	(6,616)
UGI Development Company	1,259	0	0	420	0.2%	(129)
UGI Enterprises, Inc.	0	0	0	0	0.0%	0
UGI Europe, Inc.	5,218	35,767	22,795	21,260	12.0%	(6,516)
UGI HVAC Enterprises	0	0	4,824	1,608	0.9%	(493)
UGI LNG	4,792	5,530	2,318	4,214	2.4%	(1,291)
UGI Penn HVAC Services	0	3	0	1	0.0%	(0)
UGI Properties, Inc.	0	245	349	198	0.1%	(61)
UGI Storage Company	5,903	4,465	4,152	4,840	2.7%	(1,483)
UGI Utilities, Inc.[2]	0	57,929	73,276	43,735	24.8%	(13,405)
UGI International Enterprises, Inc.	0	0	0	0	0.0%	0
United Valley Insurance	0	0	323	108	0.1%	(33)
Eliminations	0	0	0	0	0.0%	0
Subtotal Taxable Income	112,979	243,833	172,634	176,482	100.0%	(54,093)
Total Taxable Income	111,454	236,547	19,167	122,389		

Tax Savings Applicable to UGI Utilities, Inc.	(13,405)
MWF Allocation % for UGI Gas	90.69%
Total Tax Savings Allocated to UGI Gas	(12,157)
Federal Tax Rate	21%
Total Consolidated Tax Adjustment	**(2,553)**

Notes:

1. Single-member limited liability companies, i.e. disregarded entities, have been combined with their tax-regarded parent company.

2. As of October 1, 2018, UGI Penn Natural Gas, Inc. (f/ka/ "PNG") and UGI Central Penn Gas Inc. (f/k/a "CPG") merged into UGI Utilities, Inc. - Gas Division. As such, the Company's consolidated taxable income is reflected above.

	Taxable Income 2020	Adjustments		Adjusted Taxable Income
Tax Loss Entities				
UGI Corporation	(201,320)	53,453	(1)	(147,867)
AmeriGas Inc	(23)			(23)
AmeriGas Propane Holdings, Inc.	(207,170)	211,012	(2)	3,842
Amerigas Technology Group Inc.	0			0
Ashtola Production Company	(1)			(1)
Eastfield International Holdings Inc	0			0
EuroGas Holdings Inc.	0			0
Four Flags Drilling Company	0			0
Hellertown Pipeline	0			0
Homestead Holding	(607)			(607)
UGI Asset Management	0			0
UGI Black Sea Enterprises	0			0
UGI Development Company	(16,858)	11,897	(3)	(4,961)
UGI Energy Ventures, Inc.	0			0
UGI Ethanol Development Company	0			0
UGI Enterprises Inc	0			0
UGI Hunlock Dev	0			0
UGI HVAC Enterprises	0			0
UGI International China. Inc	0			0
UGI International (Romania)	0			0
UGI Penn HVAC Services	0			0
UGI Petroleum Products of DE	0			0
UGI Romania, Inc.	0			0
UGID Holding Company	(8)			(8)
Total Tax Loss	(425,987)	276,362		(149,625)

Explanations of Adjustments:

(1) UGI Corporation adjustment relates to bonus depreciation taken on non-utility fixed assets for a one-time acquistion.
(2) AmeriGas adjustment relates to one-time adjustment for entity restructuring.
(3) UGI Development adjustment relates to one-time sale of non-utility fixed assets and partnership interest.

	Taxable Income 2019	Adjustments	Adjusted Taxable Income
Tax Loss Entities			
UGI Corporation	-		0
AmeriGas Inc	(26)		(26)
Amerigas Technology Group Inc.	-		0
Ashtola Production Company	(1)		(1)
Eastfield International Holdings Inc	-		0
EuroGas Holdings Inc.	-		0
Four Flags Drilling Company	(0)		(0)
Hellertown Pipeline	-		0
Homestead Holding	(273)		(273)
UGI Asset Management	(0)		(0)
UGI Black Sea Enterprises	-		0
UGI China Inc	-		0
UGI Development Company	(5,924)		(5,924)
UGI Energy Ventures, Inc.	-		0
UGI Ethanol Development Company	-		0
UGI Hunlock Dev	-		0
UGI HVAC Enterprises	(305)		(305)
UGI International China. Inc	-		0
UGI International (Romania)	-		0
UGI LNG	-		0
UGI Penn HVAC Services	-		0
UGI Petroleum Products of DE	(0)		(0)
UGI Romania, Inc.	-		0
UGID Holding Company	(8)		(8)
United Valley Insurance	(751)		(751)
Total Tax Loss	(7,287)	0	(7,287)

	Taxable Income 2018	Adjustments	Adjusted Taxable Income
Tax Loss Entities			
UGI Corporation	0		0
AmeriGas Inc	(26)		(26)
Amerigas Technology Group Inc.	0		0
Ashtola Production Company	(1)		(1)
Eastfield International Holdings Inc	0		0
EuroGas Holdings Inc.	0		0
Four Flags Drilling Company	0		0
Hellertown Pipeline	0		0
Homestead Holding	(155)		(155)
UGI Asset Management	(0)		(0)
UGI Black Sea Enterprises	0		0
UGI Properties, Inc.	(99)		(99)
UGI Penn Natural Gas, Inc.	0		0
UGI Enterprises Inc	0		0
UGI Hunlock Dev	(90)		(90)
UGI HVAC Enterprises	(893)		(893)
UGI International China. Inc	0		0
UGI International (Romania)	0		0
UGI Penn HVAC Services	(16)		(16)
UGI Utilities, Inc.	0		0
United Valley Insurance	(239)		(239)
UGID Holding Company	(7)		(7)
Total Tax Loss	(1,525)	0	(1,525)

II-C-1

Request:

Provide test year monthly balances for “Current Gas Storage” and notes financing such storage.

Response:

Refer to UGI Gas Exhibit A (Historic), Schedules B-6 and C-5, UGI Gas Exhibit A (Future), Schedules B-6 and C-5, and UGI Gas Exhibit A (Fully Projected Future), Schedules B-6 and C-5. All of our notes can be used to finance gas storage.

Prepared by or under the supervision of: Tracy A. Hazenstab

SECTION 53.53 – BALANCE SHEET AND OPERATING STATEMENT

III-A-1

Request:

Provide a comparative balance sheet for the test year and the preceding year which corresponds with the test year date.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule B-1 for a balance sheet for each of the test years. For the preceding year which corresponds with the test year date, please refer to the response to SDR-ROR-2.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-2

Request:

Set forth the major items of Other Physical Property, Investments in Affiliated Companies and Other Investments.

Response:

Please see Attachment III-A-2.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
Other Physical Property, Investments in Affiliated Companies and Other Investments

		09/30/2021 balance
Account 121 Non-Utility Property	$	238,681
Account 123 Investment in Subsidiaries *	$	1,078,266
Account 124 Other Investments	$	75,487

* The balance in Account 123 primarily represents a residual equity investment in UGI Gas' inactive heating, ventilation and air conditioning service business ("HVAC").

III-A-3

Request:

Supply the amounts and purpose of Special Cash Accounts of all types, such as:

a. Interest and Dividend Special Deposits.

b. Working Funds other than general operating cash accounts.

c. Other special cash accounts and amounts (Temporary cash investments).

Response:

UGI Utilities, Inc. - Gas Division has no Special Cash Accounts as of September 30, 2021.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-4

Request:

Describe the nature and/or origin and amounts of notes receivable, accounts receivable from associated companies, and any other significant receivables, other than customer accounts, which appear on balance sheet.

Response:

Please see Attachment III-A-4.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
Schedule of Accounts Receivable

FERC Account Description	(000's) 9/30/21 Balances
Accounts Receivable from Associated Companies – consisting primarily of administrative services provided to UGI Energy Services, Inc.	$ 2,927
Claims Reimbursements	3,601
Damage Repair and Other Misc. Receivables	1,246
Off System Sales & Delivery Service Fees	504
Employee Merchandise & Tuition Reimbursement	84

III-A-5

Request:

Provide the amount of accumulated reserve for uncollectible accounts, method and rate of accrual, amounts accrued, and amounts written-off in each of last three years.

Response:

Please see Attachment III-A-5.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Schedule of Reserve for Uncollectible Accounts

($ in 000's except for rate of accrual)	9/30/2019	9/30/2020	9/30/2021
Account 144 - Accumulated Provision for Uncollectible Accounts	$ 7,030	$ 13,016	$ 14,518
Method [1]	Allowance	Allowance	Allowance
Rate of Accrual [2]	1.72%	1.53%	1.51%
Amounts Accrued - Uncollectible Expense [2]	$ 14,400	$ 12,810	$ 12,810
Amounts Written Off (net of recoveries)	$ 15,115	$ 7,432	$ 12,203

[1] The allowance method recognizes that a percentage of each month's sales will eventually prove to be uncollectible. Consequently, a percentage of each month's sales is charged to uncollectible expense in that month and the reserve is increased. When specific accounts are written off, they are charged to the reserve account, thus decreasing the reserve.

[2] Fiscal years 2021 and 2020 exclude $895 and $607 of uncollectible expense, respectively, which were recorded as COVID-19 regulatory assets. See further discussion at UGI Gas Exhibit A (Fully Projected Future), Schedule D-11.

III-A-6

Request:

Provide a list of prepayments and give an explanation of special prepayments.

Response:

Please see Attachment III-A-6.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
Schedule of Prepayments

Account 165		(000's) 9/30/21 Balances
Insurance	$	4,370
IS Maintenance & Services		4,794
Miscellaneous		347
PUC Assessment		2,636
Property Taxes		448
Income Taxes		1,339
Total Prepayments	$	13,935

III-A-7

Request:

Explain in detail any other significant (in amount) current assets listed on balance sheet.

Response:

Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule B-1.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-8

Request:

Explain in detail, including the amount and purpose, the deferred asset accounts that currently operate to effect or will at a later date effect the operating account supplying:

a. Origin of these accounts.

b. Probable changes to this account in the near future.

c. Amortization of these accounts currently charged to operations or to be charged in the near future.

d. Method of determining yearly amortization for the following accounts:

--Temporary Facilities
--Miscellaneous Deferred Debits
--Research and Development
--Property Losses
--Any other deferred accounts that effect operating results.

Response:

Please see Attachment III-A-8.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF DEFERRED ASSET ACCOUNTS

Account Description	(000) 9/30/21 Balances		Footnote
Deferred Recoverable Income Taxes	$	125,102	1
Pension and OPEB Benefit		88,378	2
Environmental Costs		58,161	3
Cost of Removal		21,506	4
Information Technology Program Costs (UNITE)		10,017	5
Deferred Revenue		6,160	6
Debt Issuance Costs		5,482	7
Excess Uncollectibles - COVID-19		1,502	8
Energy Efficiency and Conservation (EEC)		959	9
COVID-19 Emergency Relief Program		922	8
DSIC Over/Under		535	9
Rate Case		319	10
Total Deferred Assets	$	319,043	

Footnotes for Amortization Schedule

(1) Amortized over a period of 1-65 years dependent upon the nature of the cost.
(2) Amortized over the average remaining future service lives of plan participants.
(3) Amortized based on annual environmental rate recovery. Unrecovered costs are amortized annually at $1,865.
(4) Amortized over a period of five years.
(5) Currently not amortizing.
(6) Amortized from October 2021 - September 2022.
(7) Amortized over the term of the debt instruments.
(8) Will be amortized over 10 years, in accordance with the 2020 UGI Gas rate case settlement at Docket No. R-2019-3015162.
(9) Recovery of Over/Under collection subject to annual reconciliation.
(10) Amortized from January 2021 - December 2021.

III-A-9

Request:

Explain the nature of accounts payable to associated companies, and note amounts of significant items.

Response:

Please see Attachment III-A-9.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF ACCOUNTS PAYABLE TO ASSOCIATED COMPANIES

Affiliate Name	Balance in (000's) 9/30/2021	Nature of Payable Activity
UGI Energy Services	$ 9,374	Gas purchase activity
UGI Energy Services	6,900	Collateral deposits
UGI Corporation	3,663	Administrative services
UGI Corporation	1,575	Income tax payment made by UGI Corporate on behalf of Utilities
UGI Gas Control	1,516	Administrative and IT services
	$ 23,027	

III-A-10

Request:

Provide details of other deferred credits as to their origin and disposition policy (e.g.--amortization).

Response:

Please see Attachment III-A-10 for a detailed schedule of Deferred Credits.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Schedule of FERC 253 – Other Deferred Credits
(in Thousands)

FERC Account Description	Balance at 9/30/21	Footnote
Deferred Revenue	$ 9,748	1
Long Term Operating Lease Obligations	1,715	2
Executive Retirement Plan	6,224	3
Executive Supplemental Savings Plan	33	3
Restricted Share Awards	960	4
Short Term Disability & COBRA - Non Current	1,339	5
Long Term Disability - Non Current	337	6
Deferred CIAC	12,225	7
Uncertain Tax Position	161	8
	$ 32,743	

Footnotes for Amortization Schedule

(1) Amortized over terms of agreements, which extend to various years through 2053.
(2) Amortized over the life of the related lease.
(3) Amortized over the average remaining future service lives of plan participants.
(4) Payout awarded at the end of the performance period.
(5) The valuation reflects the costs associated with all future disability payments, and will be relieved as disability payments are made.
(6) Adjusted quarterly based on the present value of the benefit costs to be paid over the disability term for an employee.
(7) Will be applied to projects as they are placed in service.
(8) FIN48 liabilities are released when a tax year has been audited and settled or the tax year is closed under the statute of limitations. Generally, the statute of limitations is three years from the due date of the tax return.

III-A-11

Request:

Supply basis for Injury and Damages reserve and amortization thereof.

Response:

The accrual for injuries and damages expense is designed to maintain the reserve at the proper level with respect to existing and probable claims, taking into account the insurance coverage available. UGI Gas currently has insurance coverage for commercial, general, automobile and property damages in excess of $1,000,000 per claim. Actual disbursements are charged against the reserve as expenditures are made.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-12

Request:

Provide details of any significant reserves, other than depreciation, bad debt, injury and damages, appearing on balance sheet.

Response:

Please refer to the response to SDR-RR-54 for details of significant reserves appearing on the balance sheet.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-13

Request:

Provide an analysis of unappropriated retained earnings for the test year and three preceding calendar years.

Response:

Please refer to Attachment III-A-13.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Consolidated
Analysis of Unappropriated Retained Earnings
Twelve Months Ended September 30,
(Thousands of Dollars)

Line No.		Historic 2018	Historic 2019	Historic 2020	HTY 2021	FTY 2022	FPFTY 2023
1	Beginning Balance	$ 480,857	$ 579,778	$ 694,481	$ 780,180	$ 891,062	$ 1,101,494
2	Adjustments (a)		$ 1,525				
3	Net Income	148,921	133,178	135,700	145,882	175,432	186,945
4	Common Stock Dividends	(50,000)	(20,000)	(50,000)	(35,000)		-
5	Contributions from Parent					35,000	
6	Ending Balance	$ 579,778	$ 692,956	$ 780,180	$ 891,062	$ 1,101,494	$ 1,288,439

(a) Adjustments include Cumulative effect of change in accounting principle - ASC 606 - ($3,926) and Reclassification of stranded income tax effects related to TCJA - $5,451.

III-A-14

Request:

Provide schedules and data in support of the following working capital items:

a. Prepayments--List and identify all items
b. Federal Excise Tax accrued or prepaid
c. Federal Income Tax accrued or prepaid
d. Pa. State Income Tax accrued or prepaid
e. Pa. Gross Receipts Tax accrued or prepaid
f. Pa. Capital Stock Tax accrued or prepaid
g. Pa. Public Utility Realty Tax accrued or prepaid
h. State sales tax accrued or prepaid
i. Payroll taxes accrued or prepaid
j. Any adjustment related to the above items for ratemaking purposes.

Response:

Please see UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-4, and the response to III-A-6. In addition, please see the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, and the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 3.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-15

Request:

Supply an exhibit supporting the claim for working capital requirement based on the lead-lag method.

a. Pro forma expenses and revenues are to be used in lieu of book data for computing lead-lag days.

b. Respondent must either include sales for resale and related expenses in revenues and in expenses or exclude from revenues and expenses. Explain procedures followed (exclude telephone).

Response:

Please see UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-4 and the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 3.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-16

Request:

Provide detailed calculations showing the derivation of the tax liability offset against gross cash working capital requirements.

Response:

Refer to UGI Gas Schedule C-4 within Exhibit A (Historic), Exhibit A (Future), Exhibit A (Fully Projected).

Prepared by or under the supervision of: Nicole M. McKinney

III-A-17

Request:

Prepare a Statement of Income for the various time frames of the rate proceeding including:

Col. 1--Book recorded statement for the test year.
2--Adjustments to book record to annualize and normalize under present rates.
3--Income statement under present rates after adjustment in Col. 2
4--Adjustment to Col. 3 for revenue increase requested.
5--Income statement under requested rates.

a. Expenses may be summarized by the following expense classifications for purposes of this statement:

Operating Expenses (by category)
Depreciation
Amortization
Taxes, Other than Income Taxes
Total Operating Expense
Operating Income Before Taxes
Federal Taxes
State Taxes
Deferred Federal
Deferred State
Income Tax Credits
Other Credits
Other Credits and Charges, etc.
Total Income Taxes
Net Utility Operating Income
Other Income & Deductions
Other Income
Detailed listing of Other Income used in Tax Calculation
Other Income Deduction
Detailed Listing
Taxes Applicable to Other Income and Deductions
Listing Income Before Interest Charges
Listing of all types of Interest Charges and all amortization of Premiums and/or Discounts and Expenses on Debt issues

III-A-17 (Continued)

Total Interest
Net Income After Interest Charges

(Footnote each adjustment to the above statements with explanation in sufficient clarifying detail.)

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), schedules in Section D, for the Company's presentation of the requested Statements of Income and adjustments to operating revenues and expenses.

Please refer to the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, and the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 3, for explanations of the Statements of Income and adjustments to operating revenues and expenses depicted in the Section D schedules of UGI Gas Exhibit A (Historic), (Future) and (Fully Projected), the underlying sources of budgeted information, and the basis for the adjustments.

Please refer to the Direct Testimony of Paul R. Moul, UGI Gas Statement No. 6, and related UGI Gas Exhibit B, Schedule 6, for the derivation of the weighted average cost of debt used in the Company's debt interest synchronization adjustment, including the treatment of debt issuance expense, premiums and discounts used in calculating the effective cost rate for each series of long-term debt.

Please refer to the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8, for an explanation on the derivation of future test year and fully projected year sales and revenues.

Please refer to the Direct Testimony of Nicole M. McKinney, UGI Gas Statement No. 7, for an explanation of the Company's income tax adjustments.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-18

Request:

Provide comparative operating statements for the test year and the immediately preceding 12 months showing increases and decreases between the two periods. These statements should supply detailed explanation of the causes of the major variances between the test year and preceding year by detailed account number.

Response:

Please refer to Attachment III-A-18 for the exhibit of comparative operating statements.

Explanations of major variances (defined as amounts greater than $1,000 and 10%) are shown below in ($000’s):

Other Operating Revenues – Increase of $22,328 due to increases in Off System Sales (FERC 4950) ($17,300) and Late Payment Charges (FERC 4870) ($2,100).

Depreciation & Amortization – Increase of $10,953 – (FERC 4030) - The increase is due to higher capital expenditures resulting in higher additions, as well as a full year of depreciation expense on assets placed in service in 2020.

Miscellaneous Income/Expense – Decrease of $3,434 – Miscellaneous Non-operating Income/Expense (FERC 4210) decreased $2,000 due to $1,500 decrease in environmental costs and a $500 decrease in other non-operating income. Additionally, there was a one-time donation of a supplier refund of $1,000 in 2020 (FERC 4261).

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Comparative Statements of Income
(in thousands)

	12 Months Ended 9/30/2020	12 Months Ended 9/30/2021	Variance
Revenues			
Gas Utility Revenues	$ 836,387	$ 844,497	$ 8,110
Other Operating Revenues	104,764	127,092	22,328
Total Operating Revenue	941,151	971,589	30,438
Expenses			
Operating Expense	39,128	41,274	2,146
Maintenance Expense	22,935	22,446	(489)
Customer Accounts Operations Expense	34,997	34,666	(331)
Customer Service, Information and Sales Expense	3,460	3,028	(432)
Admin and General Operation Expense	105,900	107,859	1,959
Depreciation and Amortization Expense	98,201	109,154	10,953
Other taxes	9,263	8,709	(555)
Storage, Transportation and Other	402,026	404,896	2,870
Interest Income/Interest Expense	3,592	2,907	(685)
Miscellaneous Income/Expense	4,274	840	(3,434)
Long Term Debt Interest	47,160	50,204	3,045
Total Expenses before Taxes	770,935	785,982	15,047
Income Before Taxes	170,216	185,606	15,391
Tax Expense	38,783	42,692	3,909
Net Income	$ 131,433	$ 142,914	$ 11,481

III-A-19

Request:

List extraordinary property losses as a separate item, not included in operating expenses or depreciation and amortization. Sufficient supporting data must be provided.

Response:

None.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-20

Request:

Supply detailed calculations of amortization of rate case expense, including supporting data for outside services rendered. Provide the items comprising the rate case expense claim (include the actual billings or invoices in support of each kind of rate case expense), the items comprising the actual expenses of prior rate cases and the unamortized balances.

Response:

The Company's rate case expense claim is based on the normalization of projected rate case expenditures. For details, please see UGI Gas Exhibit A (Fully Projected), Schedule D-10. Historic expenditures from the Company's last rate case at Docket No. R-2019-3015162 are shown in Attachment III-A-20.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Rate Case Expense
for Docket No. R-2019-3015162

External Consultants	$	376,341
External Legal	$	619,931
Administrative and Printing	$	23,160
Total	$	1,019,432

III-A-21

Request:

Submit detailed computation of adjustments to operating expenses for salary, wage and fringe benefit increases (union and non-union merit, progression, promotion and general) granted during the test year and six months subsequent to the test year. Supply data showing for the test year:

a. Actual payroll expense (regular and overtime separately) by categories of operating expenses, i.e., maintenance, operating transmission, distribution, other.

b. Date, percentage increase, and annual amount of each general payroll increase during the test year.

c. Dates and annual amounts of merit increases or management salary adjustments.

d. Total annual payroll increases in the test year.

e. Proof that the actual payroll plus the increases equal the payroll expense claimed in the supporting data (by categories of expenses).

f. Detailed list of employee benefits and cost thereof for union and non-union personnel. Any specific benefits for executives and officers should also be included, and cost thereof.

g. Support the annualized pension cost figures.

    (i) State whether these figures include any unfunded pension costs. Explain.

    (ii) Provide latest actuarial study used for determining pension accrual rates.

h. Submit a schedule showing any deferred income and consultant fee to corporate officers or employees.

Response:

a – f. Refer to UGI Gas Exhibit A (Fully Projected), Schedule D-7 and the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2.

III-A-21 (Continued)

g. Refer to Attachment III-A-21 for the latest actuarial report showing pension accrual rates. Refer to UGI Gas Exhibit A (Fully Projected), Schedule D-14 and the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 3 for discussion of the Company's pension claim.

h. There are no significant deferred income and consultant fees to corporate officers or employees.

Prepared by or under the supervision of: Vivian K. Ressler

WillisTowersWatson

October 28, 2021

[redacted]
UGI Corporation
460 N. Gulph Road
King of Prussia, PA 19406

[redacted]

FISCAL 2022 ASC 715-30 PENSION EXPENSE

We have calculated the fiscal 2022 ASC 715-30 pension expense / (income) for the Retirement Income Plan for Employees of UGI Utilities, Inc. (RIP) to be $(5,817,609).

ASC 715-30 PENSION EXPENSE / (INCOME)

The actual fiscal 2022 pension expense / (income) for the RIP is allocated amongst the business units as follows:

UGI Utilities	$	(5,175,258)
Holding Company		(199,302)
Enterprises		(50,730)
UGID		(206,171)
HVAC		(134,708)
CPG Propane		(131,024)
UGI Gas Control		79,584
	$	(5,817,609)

The fiscal 2022 pension expense / (income) compares to actual fiscal 2021 pension expense of $4,762,015. There are multiple factors influencing the change in expense to income for fiscal 2022. The primary reasons for the change in expense are as follows:

- The decrease in the increase in the discount rate assumption from 2.90% to 3.10% decreased fiscal 2022 expense (increased income) by approximately $1.6 million
- Expected changes (including cash contributions made to the plan) based on the prior valuation decreased fiscal 2022 expense (increased income) by approximately $3.4 million
- The return on the market-related value of plan assets was higher than expected, which decreased fiscal 2022 expense (increased income) by $4.7 million
- The change in the mortality assumption from the Pri-2012-based table with the MP-19 improvement scale to the Pri-2012-based table with the MP-20 improvement scale decreased fiscal 2022 expense (increased income) by approximately $0.9 million

The pension expense / (income) is based on the projected benefit obligation (PBO) and fair asset value measured as of September 30, 2021, as reported in UGI's fiscal 2021 year-end financial disclosure. The plan's PBO as of September 30, 2021 was estimated to be $713,473,135 and the fair value of assets were reported to be $625,947,186

The details of the pension expense calculations are shown in the following exhibits:

- Exhibit I contains the expense calculations in total
- Exhibit II contains the expense components by business unit

[redacted]
October 28, 2021

The PBO was allocated to the various business units based on the codes provided in the 2021 valuation data and confirmed through the data question process. Service cost and interest cost were allocated to each unit based on actual amounts calculated for the respective participants of each unit. The expected return on assets component and the amortization components of pension expense were allocated in proportion to the PBO's of the respective business unit.

The allocation of the projected benefit obligation as of September 30, 2021 between UGI Utilities, Holding Company, UGID, HVAC, UGI Enterprises, and CPG – Propane are shown below:

	September 30, 2021 PBO
Utilities	$ 638,708,082
Holding Company	47,158,472
Enterprises	2,578,264
UGID	10,578,188
HVAC	7,020,254
CPG Propane	6,729,186
UGI Gas Control	700,689
Total	$ 713,473,135

EMPLOYEE DEMOGRAPHICS

Census data used for the determination of fiscal 2022 pension cost is as of January 1, 2021. After discussions with UGI, obligations were projected to September 30, 2021 on a no gain/loss basis, and adjusted for changes in key actuarial assumptions. There were 710 active participants as of January 1, 2021. A breakdown of the active participants by business unit is as follows:

- UGI Utilities: 686
- Holding Company: 17
- Enterprises: 0
- UGID: 0
- UGI HVAC: 0
- CPG Propane: 0
- UGI Gas Control: 7

The number of inactive participants as of January 1, 2021 is 2,787, which includes 743 terminated vested participants and 2,044 participants currently receiving benefits.

INVESTMENT EXPERIENCE

The rate of return on the fair value of assets was approximately 13.8% for the period October 1, 2020 to September 31, 2021 compared to the assumed investment return of 7.10% for that period. The market-related value of assets used to determine pension expese phases in deviations from the assumed return on the equity portion of the portfolio. For the fixed income portion of the portfolio, the market-related value is equal to the fair value. Actual investment return during fiscal 2021 caused the fiscal 2022 pension expense to decrease (income to increase).

[redacted]
October 28, 2021

ASSUMPTIONS

The fiscal 2021 and 2022 ASC 715-30 pension costs were determined using the following assumptions:

ECONOMIC ASSUMPTIONS:	FISCAL 2022	FISCAL 2021
■ Discount rate	3.10%	2.90%
■ Weighted-average salary increase assumption from age 40 to expected retirement	3.25%	3.25%
■ Expected return on assets	7.10%	7.20%
■ Mortality	Pri-2012 blue collar table with rates decreased by 4.9%, projected using Scale MP-2020 from 2012	Pri-2012 blue collar table with rates decreased by 4.9%, projected using Scale MP-2019 from 2012
■ Cash contributions	2021 target normal cost prior to reflection of interest rate stabilization ($11,364,000) based on the following schedule:	2020target normal cost prior to reflection of interest rate stabilization ($12,595,446) based on the following schedule:

Date	Amount	Date	Amount
12/15/2021	2,841,000	12/15/2020	3,044,000
3/15/2022	2,841,000	3/15/2021	3,044,000
6/15/2022	2,841,000	6/15/2021	3,044,000
9/15/2022	2,841,000	9/15/2021	3,044,000

All other assumptions and methods, as well as their rationale, are unchanged from those documented in the fiscal 2021 actuarial valuation report.

PLAN PROVISONS

All plan provisions are the same as those documented in the fiscal 2021 actuarial valuation report.

PROFESSIONAL QUALIFICATIONS AND RELIANCES

The undersigned consulting actuaries are members of the Society of Actuaries and meet the "Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States" relating to pension plans. Our objectivity is not impaired by any relationship between UGI Utilities, Inc. and our employer, Willis Towers Watson US LLC.

In preparing these results Willis Towers Watson has used the information and data provided to us by UGI. We have relied on all the data and information provided, including plan provisions as being complete and accurate. We have reviewed this information for overall reasonableness and consistency but have neither audited nor independently verified this information.

The results contained in this letter are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. Certain plan provisions may be approximated or determined to be immaterial and therefore not valued. Assumptions may be made about participant data or other factors. We have made reasonable efforts to ensure that items that are material in the context of the actuarial liabilities or costs are treated appropriately, and not excluded or included inappropriately.

Actual future experience will differ from the assumptions used in our calculations. As these differences arise, contributions or the cost for accounting purposes will be adjusted in future valuations to take changes into account. If these adjustments become material, they may result in future adjustments to the valuation model.

As required by ASC 715, the actuarial assumptions and methods employed in the development of the pension cost have been selected by the plan sponsor. U.S. GAAP requires that each significant assumption "individually represent the best estimate of the plan's future experience solely with respect to that assumption. Willis Towers Watson has evaluated the assumptions used and believes that they do not significantly conflict with what would be reasonable.

Accumulated other comprehensive (income)/loss amounts shown in the report are shown prior to adjustment for deferred taxes. Any deferred tax effects in AOCI should be determined in consultation with UGI's tax advisors and auditors. Willis Towers Watson used information supplied by UGI regarding postretirement benefit asset, postretirement benefit liability and amounts recognized in accumulated other comprehensive income as of September 30, 2021. This data was reviewed for reasonableness and consistency, but no audit was performed.

The results contained in this letter have been developed based on actuarial assumptions that, to the extent evaluated or selected by Willis Towers Watson, we consider to be reasonable. Other actuarial assumptions could also be considered to be reasonable. Thus, reasonable results differing from those presented in this report could have been developed by selecting different reasonable assumptions.

The results provided in this letter have been prepared solely for the benefit of UGI to assist with its year-end financial reporting. This email should not be used for other purposes and we accept no responsibility for any such use. It should not be relied upon by, or shared with, any third parties without Willis Towers Watson's prior written consent.

This letter provides actuarial information. It does not constitute legal, accounting, tax or investment advice. We encourage UGI to consult with qualified advisors with respect to those matters.

ASOP 56 DISCLOSURE

valuation system. It is used to perform valuations of clients' benefit plans. Quantify provides the ability to process data, calculate benefits and value benefit liabilities, develop results using applicable standards, and generate client reports. Quantify parameters provide significant flexibility to model populations and plan designs. Various demographic, economic and benefit related assumptions exist for users to model multiple demographic and economic situations.

Plan liabilities are calculated based on standard actuarial techniques, developing actuarially reasonable results using the population and parameters entered. The calculation and presentation of liabilities in Quantify relies on the assumptions used and the reasonability of the assumptions selected. Quantify incorporates standard liability methodologies that are intended to reasonably reflect a variety of economic or demographic conditions. The model itself does not evaluate any assumptions entered for reasonableness, consistency or probability of occurrence.

Quantify is designed specifically for these purposes, and we know of no material limitations that would prevent the system from being suitable for these intended purposes. The actuaries signing this report have relied on the actuaries who develop, test and maintain this system, and have also performed a limited review of results to ensure that system parameters have been set appropriately and plan provisions coded correctly.

RATE:Link is a methodology to develop spot rates to be used for measurements related to employee benefit plans. The same core methodology is used to develop all RATE:Link curves. The RATE:Link process develops term structures of interest rates from corporate bond data for each covered market. The construction of RATE:Link yield curves relies on bond data collected as of the measurement date. Information regarding quoted bond prices, yields and other bond related data is from Bloomberg Finance L.P

U.S. BOND:Link is a methodology to assist with the selection of discount rates used in measurements related to employee benefit plans. Discount rates are derived by identifying a theoretical settlement portfolio of high- quality corporate bonds sufficient to provide for a plan's projected benefit payments. The single interest rate is then determined that results in a discounted value of the plan's benefit payments that equals the market value of the selected bond portfolio.

Updated BOND:Link models are developed monthly as of the last day of the month. The construction of a BOND:Link model relies on bond data collected as of the measurement date Parameters provide the user the ability to control aspects of the model. The model output allows the user to see the effect of those parameters. Information regarding quoted bond prices, yields and other bond related data is from Bloomberg Finance L.P.

****

Please call us, if you have any questions or would like to discuss these results further.

Sincerely,

Christopher S. Zukas

Christopher S. Zukas, FSA
Director, Retirement

Direct Dial: 215-246-6104

Lori Wolfersberger, FSA
Associate Director, Retirement

215-246-4942

Enclosures

cc: [redacted]

RETIREMENT INCOME PLAN FOR EMPLOYEES OF UGI UTILITIES, INC.

Valuation Results

	As of 9/30/2021	As of 9/30/2020
Fair Value of Assets (FV)	$625,947,186	$565,993,939
Projected Benefit Obligation (PBO)	713,473,135	736,442,974
PBO Funded Percentage	87.7%	76.9%

Reconciliation of Funded Status		
Funded Status (FV – PBO)	(87,525,949)	(170,449,035)
AOCI	120,206,972	195,716,073
Market-Related Value of Assets	$612,257,070	$563,744,642

Net Periodic Pension Cost (Income)	FYE 2022 (Fiscal Year ending 9/30/2022)	FYE 2021 (Fiscal Year ending 9/30/2021)
Service Cost	$7,651,666	$8,579,477
Interest Cost	21,892,353	21,194,262
Expected Return on Assets	(42,753,638)	(39,385,109)
Amortization		
Prior Service Cost	99,586	117,566
Actuarial Loss (Gain)	7,292,424	14,255,819
Net Pension Cost (Income)	**$(5,817,609)**	**$4,762,015**

Assumptions		
Discount Rate	3.10%	2.90%
Average Salary Increases	3.25%	3.25%
Expected Return on Assets	7.10%	7.10%

RETIREMENT INCOME PLAN FOR EMPLOYEES OF UGI UTILITIES, INC.

Total Fiscal 2022 Expense by Business Unit								
	Utilities	**CGC**	**Holding Company**	**Enterprises**	**UGID**	**HVAC**	**CPG Propane**	**Total**
Service Cost	6,870,800	89,800	691,100	-	-	-	-	7,651,700
Interest Cost	19,610,100	24,500	1,446,900	77,100	318,100	213,200	202,500	21,892,400
Expected Return on Assets	(38,273,500)	(42,000)	(2,825,900)	(154,500)	(633,900)	(420,700)	(403,200)	(42,753,700)
Net Amortization	6,617,400	7,300	488,600	26,700	109,600	72,700	69,700	7,392,000
Total Expense	**(5,175,200)**	**79,600**	**(199,300)**	**(50,700)**	**(206,200)**	**(134,800)**	**(131,000)**	**(5,817,600)**

Assumptions

Discount Rate: 3.10%
Expected Return on Assets: 7.10%
Mortality: Pri-2012 blue collar table with rates decreased by 4.9%, projected using Scale MP-2020 from 2012
Other assumptions and plan provisions used in this estimate are the same as those documented in the 2021 valuation report
Census data as of January 1, 2021

III-A-22

Request:

Supply an exhibit showing an analysis, by functional accounts, of the charges by affiliates (Service Corporations, etc.) for services rendered included in the operating expenses of the filing company for the test year and for the 12-month period ended prior to the test year:

a. Supply a copy of contracts, if applicable.
b. Explain the nature of the services provided.
c. Explain basis on which charges are made.
d. If charges allocated, identify allocation factors used.
e. Supply the components and amounts comprising the expense in this account.
f. Provide details of initial source of charge and reason thereof.

Response:

Refer to Attachment III-A-22.1 for listings of applicable Gas Purchase Agreements, Asset Management Agreements and Affiliated Interest Agreements which have been previously authorized by the Commission. Refer to Attachments III-A-22.2(a) - (m) (contained on USB flash drive) for copies of the Affiliated Interest Agreements which have been previously authorized by the Commission.

See Attachment III-A-22.3 for a listing of charges from affiliates for services rendered. This listing includes the affiliate providing the service, the nature of the service, the amounts charged for Fiscal 2019 - Fiscal 2023 (Fiscal 2022 and Fiscal 2023 are planned amounts), the FERC functional account(s) where the charges are recorded, and the allocation factor (if applicable).

UGI Corporation provides administrative services to UGI Utilities, Inc. pursuant to Affiliate Interest Agreements approved by the Commission. Services provided by UGI Corporation include, but are not limited to, executive management, finance and accounting, information technology, human resources, pension fund management, internal audit, legal, shareholder relations, risk management and similar types of services.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
List of Natural Gas Purchase Agreements and Asset Management Agreements

Affiliate Name	Contract Effective Date	Contract Termination Date
UGI Energy Services, LLC		
Natural Gas Purchase Agreement	5/1/2017	30 days written notice
Natural Gas Supply & Delivery Contract (UGI-CO-1013) 97,994 MDQ	11/1/2020	10/31/2038
Natural Gas Supply & Delivery Contract (UGI-CO-1014) 25,000 MDQ	11/1/2021	10/31/2036
Peaking Delivery Service (UGI-P-1012) 23,632 MDQ	11/1/2016	3/31/2026
Peaking Delivery Service (UGI-P-1010) 106,465 MDQ	11/1/2015	3/31/2025
Peaking Delivery Service (UGI-P-1014) 40,573 MDQ	11/1/2018	3/31/2033
Natural Gas Supply & Delivery Contract (PNG-CO-1012) 36,169 MDQ	11/1/2018	10/31/2033
Peaking Delivery Service (PNG-P-1003) 21,772 MDQ	11/1/2016	3/31/2026
Transportation Service Agreement (Carverton Road) 120,000 MDQ	12/26/2013	12/25/2033
Peaking Delivery Service (CPG-P-1006) 4,750 MDQ	11/1/2015	3/31/2025
Peaking Delivery Service (CPG-P-1007) 5,000 MDQ	11/1/2018	3/31/2033
Peaking Delivery Service (CPG-P-1008) 2,519 MDQ	11/1/2018	3/31/2033
Peaking Delivery Service (UGI-P-1016) 162,177 MDQ	11/1/2021	3/31/2036
Peaking Delivery Service (UGI-P-1017) 72,299 MDQ	11/1/2021	3/31/2036
Peaking Delivery Service (UGI-P-1018) 15,891 MDQ	11/1/2021	3/31/2024
Asset Management Agreement on Columbia Pipeline	11/1/2021	10/31/2022
UGI Storage Company		
NNS Firm Delivery Contract 8,792 MDQ	4/1/2011	3/31/2026
FSS Firm Storage Contract 879,200 SCQ	4/1/2011	3/31/2026

UGI Utilities, Inc. – Gas Division
List of Affiliated Interest Agreements

Attachment #	Affiliate	Effective Dates	Docket #	Details
III-A-22.2(a)	UGI Corporation	May 1992	G-00920296	This Agreement sets forth the terms by which Utilities may provide administrative services to or receive services from Holding Company and its unregulated subsidiaries. These services will be provided on a cost basis.
III-A-22.2(b)	UGI Corporation	July 2003	G-00031008	Arrangement between UGI Utilities, Inc. and UGI Corporation and its subsidiaries under which Utilities would provide pipeline engineering, construction, maintenance and related services to UGI Companies at the higher of market rates or cost.
III-A-22.2(c)	UGI Energy Services, LLC	April 2004	G-00041075	Affiliate Interest Agreement regarding ground to be leased by UGI Energy Services, LLC from UGI Utilities, Inc. and office space to be leased by UGI Utilities, Inc. from UGI Energy Services, LLC.
III-A-22.2(d)	UGI Energy Services, LLC	Aug. 2007	G-00970552	This is an Agreement whereby Utilities would buy gas from or sell gas to GASMARK at prevailing market rates.
III-A-22.2(e)	UGI Energy Services, LLC	March 1999	G-00980646	This is an Agreement whereby Utilities would buy electric generation from Energy Services at or below prevailing market rates, for its own use at facilities throughout its service territories.
III-A-22.2(f)	AmeriGas, Inc.	May 16, 2017 – December 31, 2020	G-2016-2557069	Affiliated Interest Agreement between UGI Utilities, Inc. and AmeriGas, Inc. to support the Gas-Beyond-the-Mains customers.
III-A-22.2(g)	UGI HVAC	Dec. 2005	G-00051142	Affiliate Interest agreement in which UGI HVAC will reimburse UGIU for allocated costs related to use of space at UGIU facilities.

Attachment #	Affiliate	Effective Dates	Docket #	Details
III-A-22.2(h)	UGI HVAC	Feb. 2007	G-00071217	Affiliated Interest Agreement of UGI Utilities, Inc. with UGI HVAC Services, Inc. and UGI HVAC Enterprises (1) natural gas distribution facility installation, maintenance, testing and repair services and associated equipment (hereafter "Natural Gas Operations Services") and (2) heating, air conditioning, ventilating, plumbing, electric contracting and/or related services and associated equipment from the UGI HVAC Companies at market prices.
III-A-22.2(i)	United Valley Insurance Co.	June 1993	G-00930344	Affiliate Interest Agreement for insurance coverage through United Valley Insurance Co. Coverage through the affiliate is not mandatory and may be purchased through other independent companies when costs or coverage are more advantageous.
III-A-22.2(j)	UGI Sunbury, LLC	June 2015	G-2015-2467129	Affiliated Interest Agreement between UGI Utilities, Inc. and UGI Sunbury, LLC regarding the Sunbury Pipeline.
III-A-22.2(k)	UGI Central Gas Control, LLC	October 1, 2020 – September 30, 2030 –	G- 2020-3021989	Application of UGI Utilities, Inc. –Gas Division (“UGI Gas”) for Approval of Services Agreement whereby UGI Gas would receive gas control services from UGI Central Gas Control, LLC (“UGI Gas Control”) and UGI Gas would provide certain IT and licensing provisions to UGI Gas Control.
III-A-22.2(l)	UGI Energy Services, LLC	April 1, 2021	G-2021-3024552 G-2021-3024804	Affiliated Interest Agreement between UGI Utilities, Inc. – Electric & Gas Divisions and UGI Energy Services, LLC to sub-lease office space.
III-A-22.2(m)	UGI Energy Services, LLC	November 10, 2021	G-2021-3028753	Affiliated Interest Agreement between UGI Utilities, Inc. and UGI Energy Services, LLC regarding the Auburn Gathering System.

UGI Utilities, Inc. - Gas Division
Charges by Affiliates - Services Rendered
For the Fiscal Years Ended September 30, 2019 through 2023
$s in Thousands

		2019	2020	2021	2022	2023	FERC Functional Account	Allocation Factor	
1)	UGI Central Gas Control								
	Gas Control Services	$ 1,754	$ 1,781	$ 1,807	$ 1,807	$ 1,861	910, 923	N/A	
2)	UGI HVAC Services, Inc. (a)								
	Natural Gas Operations Services & HVAC Services	$ 565	$ 831	N/A	N/A	N/A	887, 932	N/A	
3)	United Valley Insurance Company								
	Insurance coverage	$ 4,982	$ 5,467	$ 5,570	$ 5,510	$ 5,785	925	By policy	
4)	UGI Energy Services, LLC								
	Natural Gas Purchases	$ 231,000	$ 179,000	$ 224,000	$ 224,000	$ 224,000	804	N/A	(e)
	Building sub-lease (b)	N/A	N/A	N/A	$ 327	$ 495	107, 101	Lease agreement	
	Auburn Capacity Lease	N/A	N/A	N/A	$ 141	$ 565	881	Lease agreement	
5)	UGI Corporation						(c)		
	Administrative Services	$ 12,452	$ 13,464	$ 19,423	$ 24,569	$ 25,028	920, 926, 923, 925, 408.1	(d)	

N/A Not Applicable

(a) UGI HVAC was sold to an unaffiliated company effective 9/30/2020. Therefore, there are no affiliate transactions for 2021 or future.

(b) UGI Utilities, Inc. subleases building space from UGI Energy Services, LLC, as explained at Attachment III-A-22.2. This building space is used exclusively for the UNITE It development project team and is therefore capitalized as part of the project costs within 107 (while in progress) and 101 (when complete).

(c) For 2019 - 2021, all Corporate allocation amounts were allocated to FERC 923 (Outside Services). For 2022 and 2023, the amounts are assigned to various FERC accounts, based on the nature of the underlying cost.

(d) Allocation factor used for administrative services is MWF or time spent as applicable based on nature of the service.

(e) 2022 and 2023 natural gas purchases from UGI Energy Services, LLC are estimated based on 2021 actuals.

III-A-23

Request:

Describe costs relative to leasing equipment, computer rentals, and office space, including terms and conditions of the lease. State method for calculating monthly or annual payments.

Response:

Please see Attachment III-A-23.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Costs Relative to Leasing Equipment, Computer Rental and Office Space
12 Months Ended 9/30/2021
(000's)

	Annual Expenses	Method of Computing Payment	Terms of Lease or Rental Agreement
Real Estate	$ 229	Monthly payments per lease or rental agreements. Percentage applied from Modified Wisconsin Formula for leases of shared properties.	2008 - 2025
Equipment	380	Monthly payments per lease or rental agreements. Percentage applied from Modified Wisconsin Formula for leases of shared assets.	2019 - 2024
Vehicles	1,602	Monthly payments per lease or rental agreements.	2018 - 2023
Total	$ 2,211		

Note: Balances above include long-term leases only (Original Terms of 12 months or more)

III-A-24

Request:

Submit detailed calculations (or best estimates) of the cost resulting from major storm damage.

Response:

No major storm damages have been recorded in the last five fiscal years. Accordingly, no damages are included in the future or fully projected future test year claims.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-25

Request:

Submit details of expenditures for advertising (National and Institutional and Local media). Provide a schedule of advertising expense by major media categories for the test year and the prior two comparable years with respect to:

a. Public health and safety
b. Conservation of energy
c. Explanation of Billing Practices, Rates, etc.
d. Provision of factual and objective data programs in educational institutions
e. Other advertising programs
f. Total advertising expense

Response:

Please see Attachment III-A-25.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
ADVERTISING EXPENSES
FOR THE YEARS ENDED SEPTEMBER 30, 2019 THROUGH 2023
(in US Dollars)

		FY2019	FY2020	FY2021	FY2022	FY2023
Public Health & Safety	Print/Digital	$ 146,131	$ 116,937	$ 18,489	$ 86,784	$ 87,636
Public Health & Safety	Radio					
Public Health & Safety	TV	$ 16,332		$ 42,000		
Public Health & Safety	Bill Insert					
Public Health & Safety	Other*	$ 5,175	$ 2,621	$ 2,992	$ 8,700	$ 8,784
Conservation of Energy	Print/Digital	$ 577,789	$ 356,748	$ 353,700	$ 619,256	$ 637,317
Conservation of Energy	Radio	$ -	$ -	$ -	$ -	$ -
Conservation of Energy	TV	$ -	$ -	$ -	$ -	$ -
Conservation of Energy	Bill Insert	$ 25,853	$ 26,136	$ 22,446	$ 21,854	$ 22,510
Conservation of Energy	Other*	$ -	$ -	$ -	$ -	$ -
Explanation of Bill Practices, Rates, Etc.	Print/Digital	$ 118,424	$ 182,553	$ 109,407	$ 107,540	$ 110,767
Explanation of Bill Practices, Rates, Etc.	Radio	$ -	$ -	$ -	$ -	$ -
Explanation of Bill Practices, Rates, Etc.	TV	$ -	$ -	$ -	$ -	$ -
Explanation of Bill Practices, Rates, Etc.	Bill Insert	$ 118	$ 442		$ 943	$ 971
Explanation of Bill Practices, Rates, Etc.	Other*	$ -	$ -	$ -	$ -	$ -
Data Programs in Educational Institutions	Print/Digital	$ -	$ -	$ -	$ -	$ -
Data Programs in Educational Institutions	Radio	$ -	$ -	$ -	$ -	$ -
Data Programs in Educational Institutions	TV	$ -	$ -	$ -	$ -	$ -
Data Programs in Educational Institutions	Bill Insert	$ -	$ -	$ -	$ -	$ -
Data Programs in Educational Institutions	Other*	$ -	$ -	$ -	$ -	$ -
Other Advertising Programs	Print/Digital	$ 203,711	$ 174,545	$ 189,701	$ 114,055	$ 119,877
Other Advertising Programs	Radio	$ 47,766	$ -	$ -	$ 25,393	$ 25,393
Other Advertising Programs	TV	$ -	$ -	$ -	$ -	$ -
Other Advertising Programs	Bill Insert	$ 196,628	$ 4,937	$ 85	$ 3,072	$ 3,108
Other Advertising Programs	Other*	$ 868,412	$ 1,021,754	$ 481,308	$ 869,946	$ 885,178
SUMMARY BY MEDIA						
Total Advertising Expenses	Print/Digital	$ 1,046,054	$ 830,782	$ 671,297	$ 849,551	$ 876,744
Total Advertising Expenses	Radio	$ 47,766	$ -	$ -	$ 25,393	$ 25,393
Total Advertising Expenses	TV	$ 16,332	$ -	$ 42,000	$ -	$ -
Total Advertising Expenses	Bill Insert	$ 222,599	$ 31,514	$ 22,531	$ 25,869	$ 26,589
Total Advertising Expenses	Other*	$ 873,587	$ 1,024,375	$ 484,300	$ 956,730	$ 972,814
SUMMARY BY CATEGORY						
Public Health & Safety	All	$ 167,638	$ 119,558	$ 63,481	$ 95,484	$ 96,420
Conservation of Energy	All	$ 603,642	$ 382,884	$ 376,146	$ 641,110	$ 659,827
Explanation of Bill Practices, Rates, Etc.	All	$ 118,541	$ 182,995	$ 109,407	$ 108,484	$ 111,738
Data Programs in Educational Institutions	All	$ -	$ -	$ -	$ -	$ -
Other Advertising Programs	All	$ 1,316,516	$ 1,201,235	$ 671,093	$ 1,012,466	$ 1,033,556
TOTAL		$ 2,206,338	$ 1,886,672	$ 1,220,127	$ 1,857,544	$ 1,901,541

* Other advertising includes other mass media, website and branded giveaways.

III-A-26

Request:

Provide a list of reports, data, or statements requested by and submitted to the Commission during and subsequent to the test year.

Response:

Please see Attachment III-A-26.

Prepared by or under the supervision of: Christopher R. Brown

UGI Utilities, Inc. – Gas Division
List of reports, data or statements requested by and submitted to the Commission during and subsequent to the test year.

- Test Year Plant Reporting Obligation in accordance with Final Order Paragraph #14 at Docket No. R-2019-3015162, Entered on October 8, 2020.
- PUC Annual Report
- Universal Service Program Reconciliations
- Section 1307(f) Purchased Gas Cost Filings – Book I & II
- Annual Purchase Gas Cost Compliance Filing
- Annual Gas Rate Comparison Report
- Integrated Resource Planning Report
- Quarterly Purchase Gas Cost Report
- Gas Switching Report/Choice Switching Report
- Annual Report on Unaccounted For Gas
- Residential and Commercial Price-to-Compare Report
- Quarterly Financial and Statistical Report
- P.U.C. Regulatory Assessment on Gross Receipts
- Informal complaint replies
- 52 PA Code 56.231 – Collection Results for Residential and Small Commercial Customers
- Quality of Service – Benchmark and Standards Report - including Metrix/Matrix
- PA Code 58.15 LIURP annual program evaluation report and Spending and Budget report
- 52 PA Code 62.6 - Universal Service Impact Evaluation
- Annual Conservation Plan – Status of Existing Conservation Activities
- 52 PA Code 56.100 (4) and 56.100 (5) – Cold Weather Survey of premises where heat related service is terminated during the year and resurvey of prior year's account not restored.
- Customer Assistance Program (CAP) Report
- Section 1410.1(4) – Medical Certificates and renewals submitted and accepted by the Company
  Section 1410.1(3) – Accounts Exceeding $10,000 in Arrearages
- Quarterly Rate of Return Filing
- Annual Depreciation Report
- Public Utility Security Planning & Readiness Self-Certification Form
- Gas Supply and Demand Report
- Payment Agreement Report
- Gas Delivery Enhancement Rider Rate Filing

UGI Utilities, Inc. – Gas Division
List of reports, data or statements requested by and submitted to the Commission during and subsequent to the test year.

- Annual Statistical Report
- Natural Gas Utility Update Report
- GET Gas Annual Report
- Long Term Infrastructure Improvement Plan
- Annual Asset Optimization Plan
- Annual DOT Reports
- Meter Test Reports
- Major Construction Reports (over $300K)
- Winter Reliability Data Request
- Annual Diversity Report
- Quality of Service Transaction Survey
- Bi-Annual LIURP Report
- Annual Hardship Fund Report
- State Tax Adjustment Surcharge Filing
- Universal Service Surcharge Filing
- USP Impact Evaluation
- Annual Conservation Plan - IRP - Status of Existing Conservation Activities
- LIHEAP Leveraging
- CAP Collaboratives
- CAP Credit Report
- Distribution System Improvement Charge (DSIC)
- Combined Heat and Power (CHP) Report
- EE&C Annual Rate Filing
- EE&C Annual Over/Under Reconciliation
- Annual Report – Natural and Other Gas Transmission and Gathering Systems
- Transmission Integrity Management Notifications
- Cast Iron and Bare Steel Status Report
- Safety Related Condition Report
- Incident Report – Gas Distribution/Transmission Systems
- Distribution System - Mechanical Fitting Failure Reports
- Supply Regulatory Inventory
- Low-Income Usage Reduction Program Year-end Status Report

III-A-27

Request:

Prepare a detailed schedule for the test year showing types of social and service organization memberships paid for by the Company and the cost thereof.

Response:

None are being claimed.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-28

Request:

Submit a schedule showing, by major components, the expenditures associated with Outside Services Employed, Regulatory Commission Expenses and Miscellaneous General Expenses, for the test year and prior two comparable years.

Response:

Please see Attachment III-A 28.1 for account 930.2 - Miscellaneous General Expenses.

Please see Attachment III-A-28.2 for account 923 - Outside Services Employed.

Please see Attachment III-A-28.3 for account 928 - Regulatory Commission Expenses.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Schedule of Account 930.2 - Miscellaneous General Expenses
For the Fiscal Years Ending September 30, 2019 through 2023

Expenditure Type *(in Thousands)*	**2019***	**2020**	**2021**	**2022**	**2023**
ASSOCIATION DUES	791	877	932	1,027	1,048
PROFESSIONAL FEES	124	67	230	204	206
ADVERTISING	104	455	427	438	452
SPONSORSHIPS & MEMBERSHIPS	61	553	211	420	424
EMPLOYEE BUSINESS EXPENSES	537	173	170	269	303
OTHER EXPENSES	397	553	271	319	330
GRAND TOTAL	**2,014**	**2,678**	**2,240**	**2,677**	**2,763**

*Restated

UGI Utilities, Inc. - Gas Division
Schedule of Account 923 - Outside Services Employed
For the Fiscal Years Ending September 30, 2019 through 2023

Expenditure Type *(in Thousands)*	**2019***	**2020**	**2021**	**2022**	**2023**
ADVERTISING/PUBLIC RELATIONS	325	25	47	0	0
AUDIT	1,143	1,078	712	737	760
ENVIRONMENTAL	993	568	469	786	989
IS CONSULTING SERVICES	1,544	4,277	2,987	2,894	3,522
LEGAL & OTHER PROFESSIONAL SERVICES	3,068	9,375	10,142	9,208	9,160
CORPORATE ALLOCATIONS**	12,451	13,212	19,319	9,184	9,799
MISCELLANEOUS	8,192	2,032	2,856	1,351	1,392
GRAND TOTAL	**27,718**	**30,567**	**36,534**	**24,161**	**25,622**

*Restated

**For 2019-2021, all Corporate allocation amounts were allocated to FERC 923 (Outside Services). For 2022 and 2023 the amounts are allocated to various FERC accounts, including FERC 923.

UGI Utilities, Inc. - Gas Division
Schedule of Account 928 - Regulatory Commission Expenses
For the Fiscal Years Ending September 30, 2019 through 2023

Expenditure Type *(in Thousands)*	**2019***	**2020**	**2021**	**2022**	**2023**
UGI Utilities, Inc. Gas Division Rate Case Normalization	232	910	885	263	1,000
UGI Utilities, Inc. Gas Division Other Regulatory Commission Expenses	103	(36)	(113)	131	138
GRAND TOTAL	**334**	**874**	**772**	**394**	**1,138**

*Restated

III-A-29

Request:

Submit details of information covering research and development expenditures, including major projects within the company and forecasted company programs.

Response:

UGI Gas did not have any research and development expenditures in the last five years and does not claim any expenditures in the historic, future, or fully projected future test years.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-30

Request:

Provide a detailed schedule of all charitable and civic contributions by recipient and amount for the test year.

Response:

Please see Attachment III-A-30 for a schedule of all charitable and civic contributions made for UGI Gas for the fiscal year ended September 30, 2021. No claim is being made for charitable and civic contributions.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
Schedule of Charitable and Civic Contributions
For The Year Ended September 30, 2021

Organization Name	2021
OPERATION SHARE	$ 580,914
READING IS FUNDAMENTAL INC	166,333
AMERICAN RED CROSS	100,250
THE SPARKS FOUNDATION	72,500
UNITED WAY OF BERKS COUNTY	70,000
UNITED WAY OF WYOMING VALLEY	51,500
UNITED WAY OF LACKAWANNA & WAYNE CO	50,900
THADDEUS STEVENS FOUNDATION	50,100
THE SALVATION ARMY	40,500
WILKES UNIVERSITY	40,000
UNITED WAY OF LANCASTER COUNTY	35,300
BRIDGE EDUCATIONAL FOUNDATION	26,111
SOLANCO EDUCATION FOUNDATION	25,000
PENNSYLVANIA COLLEGE OF TECH FNDN	25,000
CENTRAL PENNSYLVANIA FOOD BANK	22,785
THE PENNSYLVANIA STATE UNIVERSITY	22,100
UNITED WAY OF GREATER LEHIGH VALLEY	20,500
THE JOSHUA GROUP	20,000
LEHIGH CARBON COMMUNITY COLL FNDN	20,000
COMMUNITIES IN SCHS OF EASTERN PA I	17,500
JUNIOR ACHIEVEMENT OF NE PA	16,000
POCONO MOUNTAINS UNITED WAY	16,000
UNITED WAY OF THE CAPITAL REGION	15,500
LANCASTER SCIENCE FACTORY	15,000
KIDSPEACE CORP	15,000
FOUNDATION OF THE COLUMBIA MONTOUR	15,000
LANCASTER COUNTY CAREER & TECH FNDN	15,000
COCALICO EDUCATION FOUNDATION	15,000
WORLD AFFAIRS COUNCIL OF PHIL	15,000
MILLERSVILLE UNIVERSITY FOUNDATION	11,000
THE CHALLENGE PROGRAM, INC	10,000
SPANISH AMERICAN CIVIC ASSOC	10,000
SKILLSUSA COUNCIL	10,000
CAMP CURTIN YMCA	10,000
DA VINCI DISC CNTR OF SCI & TECH	10,000
GIRL SCOUTS IN THE HEART OF PA	10,000
LACKAWANNA COLLEGE	10,000
BERKS COUNTY COMMUNITY FNDN	10,000
EPHRATA PUBLIC LIBRARY	10,000
MASTERY CHARTER SCHOOLS FOUNDATION	10,000
MISCELLANEOUS CONTRIBUTIONS UNDER $10,000	311,425
Total	**$ 2,017,219**

III-A-31

Request:

Provide a detailed analysis of Special Services--Account 795.

Response:

Gas account 795 has no activity.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-32

Request:

Provide a detailed analysis of Miscellaneous General Expense--Account No. 801.

Response:

UGI Gas has not recorded activity to account 801 for the last five fiscal years and has no amounts allocated to this account in the FTY or FPFTY. UGI Gas does, however, capture Miscellaneous General Expense under account 930.2. For an analysis of that account's activity, please refer to the response to III-A-28.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-33

Request:

Provide a labor productivity schedule.

Response:

Please see Attachment III-A-33.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Labor Productivity Schedule
For Fiscal Years 2021 - 2023

	Actual FY-2021	Estimate FY-2022	Estimate FY-2023
Sales (Mcf)	308,783,667	338,100,349	340,396,577
Number of Employees	1,667	1,714	1,761
Number of Hours Worked	3,467,360	3,565,588	3,663,140
Miles of Main- Total	12,491	12,543	12,596
Miles of Main-Distribution	12,184	12,234	12,284
Miles of Main- Transmission	307	309	312
Number of Customers	671,662	680,529	688,670
Mcf Sales per Employee	185,233	197,258	193,297
Per Hours Worked	89	95	93
Miles of Main per Employee-Total	7	7	7
Miles of Main per Employee-Distribution	7	7	7
Miles of Main per Employee- Transmission	0	0	0
Customers per Employee	403	397	391

III-A-34

Request:

List and explain all non-recurring abnormal or extraordinary expenses incurred in the test year which will not be present in future years.

Response:

Test year expenses that are non-recurring, extraordinary or do not occur yearly, but over an extended period of years, are explained and adjusted in Section D of UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected).

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-35

Request:

List and explain all expenses included in the test year which do not occur yearly but are of a nature that they do occur over an extended period of years. (e.g.--Non-yearly maintenance programs, etc.)

[Responses shall be submitted and identified as exhibits.]

Response:

For adjustments to operating expenses, please see UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Section D and the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, and the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 3.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-36

Request:

Using the adjusted year's expenses under present rates as a base, give detail necessary for clarification of all expense adjustments. Give clarifying detail for any such adjustments that occur due to changes in accounting procedure, such as charging a particular expense to a different account than was used previously. Explain any extraordinary declines in expense due to such change of account use.

Response:

In Fiscal 2021 (HTY) and previous years, UGI Gas recorded all costs associated with services provided by UGI Corporation within FERC account 923 (Outside Services). As part of a recent FERC audit, UGI Gas was requested to record these costs based on the underlying nature of the expense. Therefore, for Fiscal 2022 and future, such allocated costs are recorded within the following FERC accounts: 920 (Administrative and general salaries); 923 (outside services employed); 925 (injuries and damages); 926 (employee pensions and benefits); and 408.1 (taxes other than income taxes). For fiscal years 2022 and 2023, this reclassification totaled $16.2 and $16.7 million respectively.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-37

Request:

Indicate the expenses that are recorded in the test year, which are due to the placement in operating service of major plant additions or the removal of major plant from operating service, and estimate the expense that will be incurred on a full-year's operation.

Response:

For a presentation of the major plant additions, cost of removal and plant retirements, refer to Schedules C-2 and C-3 in the UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected). For a presentation of depreciation expense, please refer to Schedule D-21.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-38

Request:

Submit a statement of past and anticipated changes, since the previous rate case, in major accounting procedures.

Response:

New Accounting Standard Adopted effective October 1, 2020:

Credit Losses. Effective October 1, 2020, the Company adopted ASU 2016-13, “Measurement of Credit Losses on Financial Instruments,” including subsequent amendments, using a modified retrospective transition approach. This ASU, as subsequently amended, requires entities to estimate lifetime expected credit losses for financial instruments not measured at fair value through net income, including trade and other receivables, net investments in leases, financial receivables, debt securities, and other financial instruments, which may result in earlier recognition of credit losses. Further, the new current expected credit loss model may affect how entities estimate their allowance for losses related to receivables that are current with respect to their payment terms. The adoption of the new guidance did not have a material impact on the Company's financial statements.

New Accounting Standard Adopted effective October 1, 2021:

Income Taxes. In December 2019, the FASB issued ASU 2019-12, “Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes.” This ASU simplifies the accounting for income taxes by eliminating certain exceptions within the existing guidance for recognizing deferred taxes for equity method investments, performing intraperiod allocations and calculating income taxes in interim periods. Further, this ASU clarifies existing guidance related to, among other things, recognizing deferred taxes for goodwill and allocated taxes to members of a consolidated group. This new guidance is effective for the Company for interim and annual periods beginning October 1, 2021 (Fiscal 2022) and is not expected to have a material impact on the Company's financial statements.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-39

Request:

Identify the specific witness for all statements and schedules of revenues, expenses, taxes, property, valuation, etc.

Response:

Please see the Direct Testimony of Christopher R. Brown, UGI Gas Statement No. 1, for a complete list of witnesses and areas of responsibility. The primary witness for each statement and schedule is identified on the specific document.

Prepared by or under the supervision of: Christopher R. Brown

III-A-40

Request:

Adjustments which are estimated shall be fully supported by basic information reasonably necessary.

Response:

Adjustments are fully supported in UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Sections C and D, as well as the Direct Testimony of UGI Gas Statement Nos. 1 through 11.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-41

Request:

Submit a statement explaining the derivation of the amounts used for projecting future test year level of operations and submit appropriate schedules supporting the projected test year level of operations.

Response:

The schedules shown in UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Section D, reflect this information and are the supporting detail for the Fully Projected Future Test Year for the period ending September 30, 2023. Please see the Direct Testimony of Christopher R. Brown, UGI Gas Statement No. 1, the Direct Testimony of Tracy A. Hazenstab, UGI Gas Statement No. 2, The Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 3, the Direct Testimony of Vicky A. Schappell, UGI Gas Statement No. 5, and the Direct Testimony of Nicole M. McKinney, UGI Gas Statement No. 7.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-42

Request:

If a company has separate operating divisions, an income statement must be shown for each division, plus an income statement for company as a whole.

Response:

Please refer to Attachment III-A-42 for the requested information.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Statements of Income by Division
For the Fiscal Year Ended September 30, 2021
(in thousands)

	UGI Utilities, Inc. Gas	UGI Utilities, Inc. Electric	UGI Utilities, Inc. Total
Revenues			
Electric Utility Revenues	$ -	$ 88,865	$ 88,865
Gas Utility Revenues	844,497	-	844,497
Other Operating Revenues	127,092	9,647	136,739
Total Operating Revenue	971,589	98,512	1,070,100
Expenses			
Operating Expense	41,274	10,507	51,781
Maintenance Expense	22,446	10,136	32,582
Customer Accounts Operations Expense	34,666	2,970	37,636
Customer Service, Information and Sales Expense	3,028	(57)	2,972
Admin and General Operation Expense	107,859	9,589	117,448
Depreciation and Amortization Expense	109,154	8,012	117,166
Other taxes	8,709	6,455	15,163
Storage, Transportation and Other	404,896	43,276	448,172
Interest Income / Interest Expense	2,907	1,181	4,088
Miscellaneous Income/Expense	840	161	1,001
Long Term Debt Interest	50,204	2,912	53,117
Total Expenses before Taxes	785,983	95,143	881,126
Income Before Taxes	185,606	3,369	188,975
Tax Expense	42,692	136	42,828
Net Income	$ 142,914	$ 3,232	$ 146,146

III-A-43

Request:

If a company's business extends into different states or jurisdictions, then statements must be shown listing Pennsylvania jurisdictional data, other state data and federal data separately and jointly (Balance sheets and operating accounts).

Response:

Please see Attachment III-A-43.1 (Balance Sheet by state) and Attachment III-A-43.2 (Operating Statement by state).

Additionally, the Carverton Road gate station connects the Auburn II line to the Transco interstate pipeline. In late December 2013, a FERC 63 certificate was issued to PNG (now the North Rate District).

The amounts for the year ended September 30, 2021 are as follows:

Account No.

146404	UGI ENERGY SERVICES A/R - CARVERTON ROAD	$ 86,324
489026	OTHER REVENUE - CARVERTON ROAD (FERC ORDER 63)	$1,035,888

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
BALANCE SHEET BY STATE JURISDICTION AT
SEPTEMBER 30, 2021
(thousands of dollars)

	Total Company	Pennsylvania Jurisdiction	Maryland Jurisdiction
Utility Plant	$ 3,320,845	$ 3,319,251	$ 1,594
Other Investments	1,393	1,392	1
Cash and Cash Equivalents	1,033	1,032	0
Accounts Receivable	176,968	176,883	85
Other Receivables	5,501	5,499	3
Other Assets	673,593	673,270	323
Total Assets	$ 4,179,333	$ 4,177,327	$ 2,006
Current and Accrued Liabilities	429,789	429,583	206
Other Non-current Liabilities	130,793	130,730	63
Long-term Debt	1,215,263	1,214,680	583
Other Deferred Liabilities	1,124,405	1,123,866	540
Total Liabilities	$ 2,900,251	$ 2,898,859	$ 1,392
Equity	1,279,083	1,278,469	614
Total Liabilities and Equity	$ 4,179,333	$ 4,177,327	$ 2,006

UGI Utilities, Inc. - Gas Division
Statement of Operations - by Division
For Year Ended September 30, 2021
(thousands of dollars)

	Total Company	Pennsylvania Jurisdiction	Maryland Jurisdiction
Revenues			
Gas Utility Revenues	$ 844,497	$ 843,875	$ 622
Other Operating Revenues	127,092	127,092	
Total Operating Revenue	971,589	970,967	622
Expenses:			
Operating Expense	41,274	41,256	18
Maintenance Expense	22,446	22,436	10
Customer Accounts Operations Expense	34,666	34,659	7
Customer Service and Information Operations Expense	965	965	-
Operation Sales Expense	2,063	2,061	1
Admin and General Operation Expense	107,859	107,811	47
Depreciation and Amortization Expense	109,154	109,080	74
Other taxes	8,709	8,707	2
Storage, Transportation and Other	404,896	404,500	396
Interest Income	1,466	1,465	1
Miscellaneous Income/Expense	840	840	-
Long Term Debt Interest	50,204	50,182	22
Other Interest Expense	1,441	1,440	1
Total Expenses before Taxes	785,983	785,402	579
Income Before Taxes	185,606	185,565	43
Tax Expense	42,692	42,673	19
Net Income	$ 142,914	$ 142,891	$ 24

III-A-44

Request:

Ratios, percentages, allocations and averages used in adjustments must be fully supported and identified as to source.

Response:

Ratios, percentages, allocations and averages, where utilized, are detailed in the supporting adjustments to revenue and expenses set forth in UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Section D. Please also refer to the Direct Testimony of UGI Gas Statement Nos. 1 through 11.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-A-45

Request:

Provide an explanation of any differences between the basis or procedure used in allocations of revenues, expenses, depreciation and taxes in the current rate case and that used in the prior rate case.

Response:

There have been no changes to the allocation methodology.

Prepared by or under the supervision of: Vivian K. Ressler

III-A-46

Request:

Supply a copy of internal and independent audit reports of the test year and prior calendar year, noting any exceptions and recommendations and disposition thereof.

Response:

Please see Attachment III-A-46 for the list of audit reports for the historic test year and prior year. The information contained in these reports is deemed confidential. Any party to the proceeding requiring access to these reports will be afforded the opportunity upon request, subject to the provisions of a Confidentiality Agreement to be entered into between such party and the Company pursuant to a Protective Order.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Listing of Audit Reports

Entity	Audit Report Name	Auditor	Audit Year	Date Issued
UGI Utilities, Inc.	Audited Financial Statements for UGI Utilities, Inc.	Ernst & Young, LLP	FY 2021	12/15/2021
UGI Utilities, Inc.	UGI Natural Gas - SAP Post Implementation Review	Internal Audit	FY 2021	9/3/2021
UGI Utilities, Inc.	UGI Natural Gas - Privileged Access Management	Internal Audit	FY 2021	7/17/2021
UGI Utilities, Inc.	Safety	Internal Audit	FY 2021	6/24/2021
UGI Utilities, Inc.	Manual Journal Entry	Internal Audit	FY 2021	4/23/2021
UGI Utilities, Inc.	Payroll - Overtime	Internal Audit	FY 2021	4/12/2021
UGI Utilities, Inc.	Fixed Assets	Internal Audit	FY 2021	12/10/2020
UGI Utilities, Inc.	Audited Financial Statements for UGI Utilities, Inc.	Ernst & Young, LLP	FY 2020	12/15/2020
UGI Utilities, Inc.	Compromise Assessment	Internal Audit	FY 2020	10/26/2020
UGI Utilities, Inc.	System Development Life Cycle	Internal Audit	FY 2020	9/21/2020
UGI Utilities, Inc.	FERC Gas Transactions	Internal Audit	FY 2020	9/15/2020
UGI Utilities, Inc.	Order-to-Cash Natural Gas Review	Internal Audit	FY 2020	7/10/2020
UGI Utilities, Inc.	Wire Fraud IT Investigation	Internal Audit	FY 2020	7/14/2020
UGI Utilities, Inc.	Intercompany Transactions Audit	Internal Audit	FY 2020	5/6/2020
UGI Utilities, Inc.	Data Center Audit	Internal Audit	FY 2020	5/6/2020
UGI Utilities, Inc.	Backup Process and Backup Data Management	Internal Audit	FY 2020	3/6/2020

III-A-47

Request:

Submit a schedule showing rate of return on facilities allocated to serve wholesale customers.

Response:

There are no facilities allocated for the provision to serve wholesale customers.

Prepared by or under the supervision of: Christopher R. Brown

III-A-48

Request:

Provide a copy of the latest capital stock tax report and the latest capital stock tax settlement.

Response:

Not applicable. The PA Capital Stock tax was eliminated for tax years beginning January 1, 2016. Last filed PA Capital Stock tax return was for tax year ending 9/30/2016.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-49

Request:

Submit details of calculations for Taxes, Other than Income where a company is assessed taxes for doing business in another state, or on its property located in another state.

Response:

Details of Taxes, Other Than Income where UGI Gas is assessed taxes for doing business in another state, or on its property in another state for the period ended September 30, 2021 are listed below:

1.	Maryland (Property, Franchise and PSC taxes):	$22,811
2.	West Virginia (Public Utility Tax):	$13,683
	Total:	$36,494

Prepared by or under the supervision of: Nicole M. McKinney

III-A-50

Request:

Provide a schedule of federal and Pennsylvania taxes, other than income taxes, calculated on the basis of test year per books, pro forma at present rates, and pro forma at proposed rates, to include the following categories:

a. social security
b. unemployment
c. capital stock
d. public utility realty
e. P.U.C. assessment
f. other property
g. any other appropriate categories

Response:

Refer to UGI Gas Exhibit A, Schedules D-31 and D-32 for the Historic, Future, and Fully Projected Future test years.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-51

Request:

Submit a schedule showing for the last five years the income tax refunds, plus interest (net of taxes), received from the federal government due to prior years' claims.

Response:

None.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-52

Request:

Provide detailed computations showing the deferred income taxes derived by using accelerated tax depreciation applicable to post-1969 utility property increases productive capacity, and ADR rates on property. (Separate between state and federal; also, rate used)

a. State whether tax depreciation is based on all rate base items claimed as of the end of the test year, and whether it is the annual tax depreciation at the end of the test year.

b. Reconcile any difference between the deferred tax balance, as shown as a reduction to measures of value (rate base), and the deferred tax balance as shown on the balance sheet.

Response:

See Schedules D-33 and D-34 in Exhibit A (Historic), Exhibit A (Future), and Exhibit A (Fully Projected) for the computation of federal and state deferred income taxes.

a. Tax depreciation subject to normalization is based on depreciable property as of the end of the test year. Further, tax depreciation is annualized as of the end of the test year period.

b. The accumulated deferred tax balance, as shown as a reduction to measures of value, represents the annualized balance based on the plant in service included in the measures of value, and then pro-rated according to the normalization rules under Treasury Regulation 1.167(l)-1(h)(6)(ii). The balance sheet represents the budgeted balance.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-53

Request:

Submit a schedule showing a breakdown of the deferred income taxes by state and federal per books, pro-forma existing rates, and under proposed rates.

Response:

Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule D-33.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-54

Request:

Submit a schedule showing a breakdown of accumulated investment tax credits (3 percent, 4 percent, 7 percent, 10 percent and 11 percent), together with details of methods used to write-off the unamortized balances.

Response:

As of fiscal year ended September 30, 2021, the amount of UGI Gas' accumulated 3% investment tax credit was $1,676,149.

This investment credit is amortized on a straight-line basis. The annual amortization of the credit is $318,420.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-55

Request:

Submit a schedule showing the adjustments for taxable net income per books (including below-the-line items) and pro-forma under existing rates, together with an explanation of any difference between the adjustments. Indicate charitable donations and contributions in the tax calculation for rate making purposes.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedules A-1, D-1, D-33 and D-34. For ratemaking purposes, charitable donations and contributions are not being claimed and are excluded from test year data.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-56

Request:

Submit detailed calculations supporting taxable income before state and federal income taxes where the income tax is subject to allocation due to operations in another state, or due to operation of other taxable utility or non-utility business, or by operating divisions or areas.

Response:

Please see Attachment III-A-56.

UGI Gas has established nexus for income tax purposes in other states due to having storage inventory in those states. Because of having nexus with those states, it files tax returns with income allocated to those states. Income is allocated according to the apportionment rules for each state. Attachment III-A-56 reflects that allocation of taxable income.

Prepared by or under the supervision of: Nicole M. McKinney

UGI Utilities, Inc. - Gas Division
Allocation of Income to Other States, Other Operating Divisions, & Non-Utility Operations
Historic Test Year - 9/30/21
In Thousands (000)

	(1) As Filed	(2) PA	(3) Non-PA
Revenue	856,466	856,439	641
Operating Expenses	(499,291)	(499,276)	(374)
Depr & Amort	(109,154)	(109,150)	(82)
Taxes Other Than Income	(8,709)	(8,708)	(7)
Total Operating Expenses	(617,154)	(617,135)	(462)
Interest Expense	(50,148)	(50,146)	(38)
Book/Tax Depr Adj	(77,524)	(77,522)	(58)
Taxable Income	111,640	111,637	84

III-A-57

Request:

Submit detailed calculations showing the derivation of deferred income taxes for amortization of repair allowance if such policy is followed.

[Note: Submit additional schedules if the company has more than one accounting area.]

Response:

Please See Exhibit A, Schedule D-33 (Historic); Exhibit A, Schedule D-33 (Future); and Exhibit A, Schedule D-33 (Fully Projected) for the repairs deferred income tax expense for each of the respective years.

Please see Exhibit A, Schedule C-6 (Historic); Exhibit A, Schedule C-6 (Future); and Exhibit A Schedule C-6 (Fully Projected) for the repairs accumulated deferred income tax balance for each of the respective years.

Also, please see the Direct Testimony of Nicole M. McKinney, UGI Gas Statement No. 7 for an explanation of the Company's regulatory treatment of the repairs tax allowance.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-58

Request:

Furnish a breakdown of major items comprising prepaid and deferred income tax charges and other deferred income tax credits and reserves by accounting areas.

Response:

See UGI Gas Exhibit A, Schedule C-6 (Historic) for deferred taxes relative to plant in service.

The net value of deferred taxes on items other than plant in service at fiscal year ended 9/30/2021 is a deferred tax liability of $40,129,243.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-59

Request:

Provide details of the Federal Surtax Credit allocated to the Pennsylvania jurisdictional area, if applicable.

Response:

Not applicable.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-60

Request:

Explain the reason for the use of cost of removal of any retired plant figures in the income tax calculations.

Response:

For income tax purposes, the cost of removal is deductible in the year incurred. For book purposes, the cost is amortized over 60 months.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-61

Request:

Submit the corresponding data applicable to Pennsylvania Corporate Income Tax deferment.

a. Show the amounts of straight line tax depreciation and accelerated tax depreciation, the difference between which gave rise to the normalizing tax charged back to the test year operating statement.

b. Show normalization for both Federal and State Income Taxes.

c. Show tax rates used to calculate tax deferment amount.

Response:

a. & b. Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), UGI Gas Exhibit A (Fully Projected), Schedules D-33 and D-34, which provide details of the deferred income taxes from normalized depreciation separately for Federal and State.

c. The U.S. gross federal income tax rate is 21%, but net of the federal benefit for state taxes it becomes 18.90%. The state tax rate is 9.99%.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-62

Request:

Provide the accelerated tax depreciation and the book depreciation used to calculate test year deferrals in amounts segregated as follows:

For:

a. Property installed prior to 1970

b. Property installed subsequent to 1969 (indicate increasing capacity additions and nonincreasing capacity additions).

Response:

a. There is no property installed prior to 1970 for tax purposes.

b. Tax depreciation related to accelerated cost recovery system (ACRS) and modified accelerated cost recovery system (MACRS) is calculated on the full taxable basis and income taxes are normalized on the difference between ACRS/MACRS depreciation and book depreciation. For property installed subsequent to 1969, see Section D, Schedule D-34 within UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected).

Prepared by or under the supervision of: Nicole M. McKinney

III-A-63

Request:

State whether all tax savings due to accelerated depreciation on property installed prior to 1970 have been passed through to income. (If not, explain).

Response:

All tax savings have been passed through and UGI Gas has no remaining accelerated depreciation on property installed prior to 1970.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-64

Request:

Show any income tax loss/gain carryovers from previous years that may effect test year income taxes or future year income taxes. Show loss/gain carryovers by years of origin and amounts remaining by years at the end of the test year.

Response:

Not applicable.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-65

Request:

State whether the company eliminates any tax savings by the payment of actual interest on construction work in progress not in rate base claim.

If response is affirmative:

a. Set forth amount of construction claimed in this tax savings reduction. Explain the basis for this amount.

b. Explain the manner in which the debt portion of this construction is determined for purposes of the deferral calculations.

c. State the interest rate used to calculate interest on this construction debt portion, and the manner in which it is derived.

d. Provide details of calculation to determine tax saving reduction. State whether state taxes are increased to reflect the construction interest elimination.

Response:

No. Interest deduction for rate making purposes is synchronized with the interest component of the capital structure.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-66

Request:

Provide a detailed analysis of Taxes Accrued per books as of the test year date. Also supply the basis for the accrual and the amount of taxes accrued monthly.

Response:

Please see Attachments III-A-66.1 (Historic), III-A-66.2 (Future), and III-A-66.3 (Fully Projected).

Prepared by or under the supervision of: Nicole M. McKinney

UGI Utilities, Inc. - Gas Division
Schedule of Taxes Accrued per Books - Historic Test Year
Twelve Months Ended September 30, 2021
(Thousands of Dollars)

Description	Amount	Basis for Accrual of Tax	Amount of Tax Accrued Monthly
PA Public Utility Realty Tax	(280)	Tax is based on assessed valuation of the company's taxable real property.	Monthly accrual is one twelfth of total estimated tax.
PA Unemployment Tax	(104)	Tax based on employer's unemployment rate multiplied by a maximum of $10,000 per employee.	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Use Tax	(1)	Tax based on taxable purchases on which sales tax has not been charged at the rate of 6%.	Accrual computed monthly by applying the tax rate to applicable purchases.
Federal Unemployment Tax	157	Tax is based on the first $7,000 earned by an employee at a taxable rate of 6%.	Accrual is computed monthly by applying the tax rate to taxable earnings.
FICA	47	Tax for OASDI is based on the first $142,800 earned by an employee at a taxable rate of 6.2%. Tax for HI is based on all wages at a taxable rate of 1.45%	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Corporate Net Income Tax	(1,339)	Tax is based on taxable net income as defined by the Pennsylvania Department of Revenue at the current rate of 9.99%. Note, the amount reflected is negative due to cash payments exceeding accrued tax expense.	Accrual is computed monthly by applying the rate to taxable income for the month.
Federal Income Tax	(3,188)	Tax is based on taxable net income as defined by and reported to the IRS. Current rate is 21% of taxable income. Note, the amount reflected is negative due to cash payments exceeding accrued tax expense.	Accrual is computed monthly by applying the rate to taxable income for the month.
	$ (4,709)		

UGI Utilities, Inc. - Gas Division
Schedule of Taxes Accrued per Books - Future Test Year
Twelve Months Ended September 30, 2022
(Thousands of Dollars)

Description	Amount	Basis for Accrual of Tax	Amount of Tax Accrued Monthly
PA Public Utility Realty Tax	0	Tax is based on assessed valuation of the company's taxable real property.	Monthly accrual is one twelfth of total estimated tax.
PA Unemployment Tax	0	Tax based on employer's unemployment rate multiplied by a maximum of $10,000 per employee.	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Use Tax	(1)	Tax based on taxable purchases on which sales tax has not been charged at the rate of 6%.	Accrual computed monthly by applying the tax rate to applicable purchases.
Federal Unemployment Tax	0	Tax is based on the first $7,000 earned by an employee at a taxable rate of 6%.	Accrual is computed monthly by applying the tax rate to taxable earnings.
FICA	0	Tax for OASDI is based on the first $147,000 earned by an employee at a taxable rate of 6.2%. Tax for HI is based on all wages at a taxable rate of 1.45%	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Corporate Net Income Tax	0	Tax is based on taxable net income as defined by the Pennsylvania Department of Revenue at the current rate of 9.99%	Accrual is computed monthly by applying the rate to taxable income for the month.
Federal Income Tax	0	Tax is based on taxable net income as defined by and reported to the IRS. Current rate is 21% of taxable income.	Accrual is computed monthly by applying the rate to taxable income for the month.
	$ (1)		

UGI Utilities, Inc. - Gas Division
Schedule of Taxes Accrued per Books - Fully Projected Future Test Year
Twelve Months Ended September 30, 2023
(Thousands of Dollars)

Description	Amount	Basis for Accrual of Tax	Amount of Tax Accrued Monthly
PA Public Utility Realty Tax	0	Tax is based on assessed valuation of the company's taxable real property.	Monthly accrual is one twelfth of total estimated tax.
PA Unemployment Tax	0	Tax based on employer's unemployment rate multiplied by a maximum of $10,000 per employee.	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Use Tax	(1)	Tax based on taxable purchases on which sales tax has not been charged at the rate of 6%.	Accrual computed monthly by applying the tax rate to applicable purchases.
Federal Unemployment Tax	0	Tax is based on the first $7,000 earned by an employee at a taxable rate of 6%.	Accrual is computed monthly by applying the tax rate to taxable earnings.
FICA	0	Tax for OASDI is based on the first $147,000 earned by an employee at a taxable rate of 6.2%. Tax for HI is based on all wages at a taxable rate of 1.45%	Accrual is computed monthly by applying the tax rate to taxable earnings.
PA Corporate Net Income Tax	0	Tax is based on taxable net income as defined by the Pennsylvania Department of Revenue at the current rate of 9.99%	Accrual is computed monthly by applying the rate to taxable income for the month.
Federal Income Tax	0	Tax is based on taxable net income as defined by and reported to the IRS. Current rate is 21% of taxable income.	Accrual is computed monthly by applying the rate to taxable income for the month.
	$ (1)		

III-A-67

Request:

For the test year as recorded on test year operating statement:

a. Supply the amount of federal income taxes actually paid.

b. Supply the amount of the federal income tax normalizing charge to tax expense due to excess of accelerated tax depreciation over book depreciation.

c. Supply the normalizing tax charge to federal income taxes for the 10% Job Development Credit during test year.

d. Provide the amount of the credit of federal income taxes due to the amortization or normalizing yearly debit to the reserve for the 10% Job Development Credit.

e. Provide the amount of the credit to federal income taxes for the normalizing of any 3% Investment Tax Credit Reserve that may remain on the utility books.

Response:

a & b. Refer to UGI Gas Exhibit A, Schedule D-33 for the Historic, Future, and Fully Projected test years.

c & d. None.

e. $318,420.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-68

Request:

Provide the debit and credit in the test year to the Deferred Taxes due to Accelerated Depreciation for federal income tax, and provide the debit and credit for the Job Development Credits (whatever account) for test year.

Response:

The debit and credit in the test year to the Deferred Taxes due to Accelerated Depreciation for federal income tax is as follows:

A/C #	Account Description	Debit	Credit
00410XXX	Deferred Tax Expense	$XXX,XXX	
00282XXX	Accumulated Deferred Taxes		$XXX,XXX

UGI Gas has no Job Development Credits.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-69

Request:

Reconcile all data given in answers to questions on income taxes charged on the test year operating statement with regard to income taxes paid, income taxes charged because of normalization and credits due to yearly write-offs of past years' income tax deferrals, and from normalization of investment tax and development credits. (Both state and federal income taxes.)

Response:

Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Section D, Schedules D-33 and D-34. Also, refer to the Direct Testimony of Nicole M. McKinney, UGI Gas Statement No. 7.

UGI Gas does not have development credits.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-70

Request:

With respect to determination of income taxes, federal and state:

a. Show income tax results of the annualizing and normalizing adjustments to the test year record before any rate increase.

b. Show income taxes for the annualized and normalized test year.

c. Show income tax effect of the rate increase requested.

d. Show income taxes for the normalized and annualized test year after application of the full rate increase.

[It is imperative that continuity exists between the income tax calculations as recorded for the test year and the final income tax calculation under proposed rates. If the company has more than one accounting area, then additional separate worksheets must be provided in addition to those for total company.]

Response:

Refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Section D, Schedules D-33 and D-34.

Prepared by or under the supervision of: Nicole M. McKinney

III-A-71

Request:

In adjusting the test year to an annualized year under present rates, explain any changes that may be due to book or tax depreciation change and to debits and credits to income tax expense due to accelerated depreciation, deferred taxes, job development credits, tax refunds or other items.

(The above refers only the adjustments going from recorded test year to annualized test year.)

Response:

Adjustments relative to the subject matter were made to recorded data to annualize the years' data and are based on property balances at the end of the test year to reflect a full year's expense of deferral. See the Direct Testimony of Nicole M. McKinney, UGI Gas Statement No. 7.

Prepared by or under the supervision of: Nicole M. McKinney

III-E-1

Request:

If Unrecovered Fuel Cost policy is implemented, provide the following:

a. State manner in which amount of Unrecovered Fuel Cost on balance sheet at the end of the test year was determined, and the month in test year in which such fuel expense was actually incurred. Provide amount of adjustment made on the rate case operating account for test year-end unrecovered fuel cost. (If different than balance sheet amount, explain.)

b. Provide amount of Unrecovered Fuel Cost that appeared on the balance sheet at the opening date of the test year, and the manner in which it was determined. State whether this amount is in the test year operating account.

Response:

Please see Attachment III-E-1.

Prepared by or under the supervision of: Christopher R. Brown

UGI Utilities, Inc. - Gas Division
Unrecovered Fuel Costs and Revenues
For the periods ending September 30, 2020 and 2021
U.S. Dollars in Thousands

Month	Year	Fuel Costs	Revenues	Under (Over) Collection
October	2019	15,641	11,629	4,011
November	2019	34,905	24,096	10,809
December	2019	50,427	42,293	8,134
January	2020	52,699	55,304	(2,605)
February	2020	41,623	54,884	(13,261)
March	2020	36,884	42,660	(5,776)
April	2020	15,287	26,685	(11,399)
May	2020	12,053	13,586	(1,532)
June	2020	9,253	7,460	1,793
July	2020	8,801	4,807	3,994
August	2020	8,843	4,602	4,241
September	2020	9,730	6,187	3,543
October	2020	7,316	7,877	(560)
November	2020	25,244	14,334	10,910
December	2020	41,256	33,994	7,262
January	2021	44,984	47,674	(2,690)
February	2021	50,341	49,207	1,133
March	2021	38,340	48,327	(9,987)
April	2021	15,703	24,161	(8,458)
May	2021	11,710	13,549	(1,839)
June	2021	8,908	8,144	764
July	2021	8,141	5,075	3,065
August	2021	8,258	4,746	3,513
September	2021	7,423	5,168	2,254

Beginning Balance as of 9/30/2019	546
Purchased Fuel Cost Adjustment	7,318
Unrecovered Purchased Fuel Cost as of 9/30/2021	$ 7,865

* For further information regarding the unrecovered purchased fuel cost, please refer to the 1307(f) filing.

III-E-2

Request:

Provide details of items and amounts comprising the accounting entries for Deferred Fuel Cost at the beginning and end of the test year.

Response:

Refer to Attachment III-E-1 for an analysis of entries made to the Deferred Fuel Cost Account during the Fully Projected Future Test Year.

Prepared by or under the supervision of: Christopher R. Brown

III-E-3

Request:

Submit a schedule showing a reconciliation of test year MCF sales and line losses. List all amounts of gas purchased, manufactured and transported.

Response:

The data is provided below for the Historic Year:

Throughput -	309,310,561 Mcf
Company Use Gas -	397,967 Mcf
Line Loss -	684,594 Mcf
Total Sendout -	310,393,123 Mcf

Prepared by or under the supervision of: Christopher R. Brown

III-E-4

Request:

Provide detailed calculations substantiating the adjustment to revenues for annualization of changes in number of customers and annualization of changes in volume sold for all customers for the test year.

a. Break down changes in number of customers by rate schedules.

b. If an annualization adjustment for changes in customers and changes in volume sold is not submitted, please explain.

Response:

a. Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8.

b. Not applicable.

Prepared by or under the supervision of: Sherry A. Epler

III-E-5

Request:

Submit a schedule showing the sources of gas supply associated with annualized MCF sales.

Response:

Please see the response to III-E-30.

Prepared by or under the supervision of: Christopher R. Brown

III-E-6

Request:

Supply, by classification, Operating Revenues--Miscellaneous for test year.

Response:

Please refer to Attachment III-E-6 for a schedule of Operating Revenues – Miscellaneous for the years ended September 30, 2021-2023.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Operating Revenues - Miscellaneous
For the Years Ended September 30, 2021, 2022, and 2023
($ in Thousands)

Account No.		Actual 12 Months 9/30/2021	Budgeted 12 Months 9/30/2022	Budgeted 12 Months 9/30/2023
487	Forfeited Discounts	$ 4,881	$ 5,555	$ 5,603
488	Miscellaneous Service Revenues	$ 1,277	$ 923	$ 923
493	Rent from Gas Property	$ 2,283	$ 2,338	$ 2,338
495	Other Gas Revenues	$ 3,192	$ 1,075	$ 1,075
	Total	$ 11,633	$ 9,891	$ 9,939

III-E-7

Request:

Provide details of respondent's attempts to recover uncollectible and delinquent accounts.

Response:

The Company performs collections activities on all active accounts in accordance with applicable Commission requirements. When those collection activities are exhausted, UGI Gas refers bad debt placements to a collection agency for continuing collection action. When the service is closed, the customer receives a closing bill. Placements are sent to the collection agency within sixty (60) days after the service is closed. The day after the final bill is due, a Final Bill Reminder is mailed. The reminder states that their balance must be paid to avoid being turned over to a collection agency. Fourteen (14) days later the account is sent to collections.*

*Due to the financial impact many households were facing at the start of the pandemic, on March 20th, 2020, the Company advised the third party collection agencies to cease collection activities on all accounts placed. The Company advised the agencies to resume collection efforts on October 9th, 2020.

Prepared by or under the supervision of: Vivian K. Ressler

III-E-8

Request:

Describe how the net billing and gross billing is determined. For example, if the net billing is based on the rate blocks plus FCA and STA, and the gross billing is determined by a percentage increase (1, 3 or 5 percent), then state whether the percentage increase is being applied to all three items of revenue--rate blocks plus FCA and STA.

Response:

A. The total net bill is the sum of:

1. Tariff Amount – calculated as the volume of usage priced through the rate schedule tables.

2. Currently effective surcharges.

3. Sales Tax – calculated as the product of the current sales tax percentage (6%) and the sum of the above. Sales tax is not applied to residential customers when the purchase of natural gas is solely for the purchaser's own residential use and non-residential customers are exempt from sales tax if the purchaser is entitled to claim an exemption under Chapter 61 of the Pa. Code § 32.25 subsection (d). If a tax exemption certificate is on file for these non-residential customers, the tax base is adjusted in accordance with the exemption certificate.

B. The gross bill is the sum of:

1. Total net bill as described above.

2. Late payment charges on any unpaid previous balance, if any, as of the billing date.

3. Late payment charge for payment made after the due date (see III-E-9 for details on late payment charges applied).

III-E-8 (Continued)

C. The percentage increase (late payment charge) is applied to the base tariff rate and the State Tax Adjustment Surcharge. The late payment charge is not applied to Sales Tax or to previously applied late payment charges.

Prepared by or under the supervision of: Christopher R. Brown

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III-E-9

Request:

Describe the procedures involved in determining whether forfeited discounts or penalties are applied to customer billing.

Response:

Please refer to UGI Gas Exhibit F, Rules 8.7 and 8.8 of the current tariff for UGI Utilities, Inc. – Gas Division.

Prepared by or under the supervision of: Vivian K. Ressler

III-E-10

Request:

Provide annualization of revenues as a result of rate changes occuring during the test year, at the level of operations as of end of the test year.

Response:

Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8, for detail on the annualization of revenues.

Prepared by or under the supervision of: Sherry A. Epler

III-E-11

Request:

Provide a detailed billing analysis supporting present and proposed rates by customer classification and/or tariff rate schedule.

Response:

Please see UGI Gas Exhibit E - Proof of Revenue.

Prepared by or under the supervision of: Sherry A. Epler

III-E-12

Request:

Provide a schedule showing residential and commercial heating sales by unit (MCF) per month and degree days for the test year and three preceding twelve month periods.

Response:

Please see Attachment III-E-12.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Divison
Residential and Commercial Heating Sales (Mcf's)

	October	November	December	January	February	March	April	May	June	July	August	September	Total
Degree Days													
2019-2020	266	764	923	916	822	595	488	217	13	-	0	88	5,091
2020-2021	309	507	940	1,025	969	649	388	204	12	-	-	53	5,056
2021-2022	350	672	952	1,120	962	805	414	164	30	-	16	83	5,568
2022-2023	350	672	952	1,120	962	805	414	164	30	-	16	83	5,568
Residential Heating Sales (Mcf's) Rate R & RT													
2019-2020	1,977,891	6,014,209	8,925,233	8,104,445	6,714,931	4,895,846	4,566,434	2,185,065	1,053,201	888,240	580,207	994,831	46,900,533
2020-2021	2,169,174	5,120,377	7,562,594	9,345,589	8,819,953	5,917,015	3,366,585	1,808,723	872,642	845,836	818,636	783,903	47,431,027
2021-2022	2,671,769	5,862,928	8,291,318	10,361,516	8,141,334	6,976,232	3,690,878	1,526,097	925,626	729,249	775,573	1,193,342	51,145,864
2022-2023	2,700,030	5,934,777	8,395,143	10,487,388	8,236,456	7,062,737	3,738,507	1,543,663	937,351	738,223	784,965	1,207,730	51,766,968
Commercial Heating Sales (Mcf's) Rate N, NT & DS													
2019-2020	1,590,284	4,390,483	4,778,368	5,665,205	5,297,323	3,816,666	2,154,147	1,221,720	700,738	675,299	618,799	812,414	31,721,446
2020-2021	1,605,896	3,133,009	4,986,324	6,144,334	5,700,403	4,044,056	2,339,529	1,359,270	780,178	785,422	797,097	832,960	32,508,479
2021-2022	1,806,771	3,840,822	5,317,283	6,817,421	5,385,910	4,788,579	2,742,425	1,192,713	872,489	719,783	737,003	1,008,125	35,229,324
2022-2023	1,826,604	3,876,925	5,368,979	6,879,232	5,437,894	4,832,754	2,759,830	1,201,489	878,119	724,695	741,897	1,015,244	35,543,663

III-E-13

Request:

Provide a schedule of present and proposed tariff rates showing dollar change and percent of change by block. Also, provide an explanation of any change in block structure and the reasons therefor.

Response:

Please see UGI Gas Exhibit E – Proof of Revenue and the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8.

Prepared by or under the supervision of: Sherry A. Epler

III-E-14

Request:

Provide the following statements and schedules. The schedules and statements for the test year portion should be reconciled with the summary operating statement.

a. An operating revenues summary for the test year and the year preceding the test year showing the following (Gas MCF):

(i) For each major classification of customers

(a) MCF sales
(b) Dollar Revenues
(c) Forfeited Discounts (Total if not available by classification)
(d) Other and Miscellaneous revenues that are to be taken into the utility operating account along with their related costs and expenses.

(ii) A detailed explanation of all annualizing and normalizing adjustments showing method utilized and amounts and rates used in calculation to arrive at adjustment.

(iii) Segregate, from recorded revenues from the test year, the amount of revenues that are contained therein, by appropriate revenue categories, from:

(a) Fuel Adjustment Surcharge
(b) State Tax Surcharge
(c) Any other surcharge being used to collect revenues.
(d) Provide explanations if any of the surcharges are not applicable to respondent's operations.

[The schedule should also show number of customers and unit of sales (Mcf), and should provide number of customers by service classification at beginning and end of test year.]

b. Provide details of sales for resale, based on periods five years before and projections for five years after the test year, and for the test year. List customers, Mcf sold,

III-E-14 (Continued)

revenues received, source of Mcf sold (storage gas, pipeline gas, manufactured gas, natural or synthetic), contracted or spot sales, whether sales are to affiliated companies, and any other pertinent information.

Response:

a. (i)(a) Please see Attachment III-E-19.

(i)(b)-(d) Please see UGI Gas Exhibit A, Schedule D-5 (Historic), UGI Gas Exhibit A, Schedule D-5 (Future), and UGI Gas Exhibit A, Schedule D-5 (Fully Projected).

(ii) Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8.

(iii) Please see UGI Gas Exhibit E, Proof of Revenue.

b. None.

Prepared by or under the supervision of: Sherry A. Epler

III-E-15

Request:

State manner in which revenues are being presented for ratemaking purposes:

a. Accrued Revenues

b. Billed Revenues

c. Cash Revenues

Provide details of the method followed.

Response:

Fully Projected Test Year revenues at present and proposed rates are based upon a calculation applying present rates to projected volumes and number of customers and proposed rates to projected volumes and number of customers.

Prepared by or under the supervision of: Sherry A. Epler

III-E-16

Request:

If revenue accruing entries are made on the books at end of each fiscal period, give entries made accordingly at the end of the test year and at the beginning of the year. State whether they are reversed for ratemaking purposes.

Response:

The amount of unbilled revenue accrued at September 30, 2021 and September 30, 2020 for UGI Gas was $4,555,456 and $11,325,496, respectively. The Company annualizes revenue for ratemaking purposes eliminating the impacts of unbilled revenues.

Prepared by or under the supervision of: Vivian K. Ressler

III-E-17

Request:

State whether any adjustments have been made to expenses in order to present such expenses on a basis comparable to the manner in which revenues are presented in this proceeding (i.e.--accrued, billed or cash).

Response:

No such adjustments have been made to expenses. Expenses are presented on a basis comparable to the manner in which revenues are presented.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-E-18

Request:

If the utility has a Fuel Adjustment Clause:

a. State the base fuel cost per MCF chargeable against basic customers' rates during the test year. If there was any change in this basic fuel charge during the test year, give details and explanation thereof.

b. State the amount in which the fuel adjustment clause cost per MCF exceeds the fuel cost per MCF charged in base rates at the end of the test year.

c. If fuel cost deferment is used at the end of the test year, give

    (i) The amount of deferred fuel cost contained in the operating statement that was deferred from the 12-month operating period immediately preceding the test year.

    (ii) The amount of deferred fuel cost that was removed from the test period and deferred to the period immediately following the test year.

d. State the amount of Fuel Adjustment Clause revenues credited to the test year operating account.

e. State the amount of fuel cost charged to the operating expense account in the test year which is the basis of Fuel Adjustment Clause billings to customers in that year. Provide summary details of this charge.

f. From the recorded test year operating account, remove the Fuel Adjustment Clause Revenues. Also remove from the test year recorded operating account the excess of fuel cost over base rate fuel charges, which is the basis for the Fuel Adjustment charges. Explain any difference between FAC Revenues and excess fuel costs. [The above is intended to limit the operating account to existing customers' base rate revenues and expense deductions relative thereto].

III-E-18 (Continued)

Response:

The Company does not have a Fuel Adjustment Clause. The Company recovers its purchased gas costs through purchased gas cost rates under Section 1307(f) of the Public Utility Code.

Prepared by or under the supervision of: Christopher R. Brown

III-E-19

Request:

Provide growth patterns of usage and customer numbers per rate class, using historical and projected data.

Response:

Please see Attachment III-E-19.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Divison
Usage and Customer Growth Patterns for Period Ending September 30

Number of Customers September Year End	September 2019	September 2020	September 2021	September 2022	September 2023
Residential	504,640	516,177	523,495	528,286	535,853
Commercial	48,175	49,213	49,270	50,276	50,853
Industrial	669	674	707	658	655
Subtotal-Retail	553,484	566,064	573,472	579,220	587,361
Transportation-Other	100,932	102,931	98,190	101,309	101,309
Total	654,416	668,995	671,662	680,529	688,670

Total Fiscal Year Sales (Mcf's)	September 2019	September 2020	September 2021	September 2022	September 2023
Residential	43,463,105	41,103,074	41,637,491	44,965,329	45,375,042
Commercial	16,320,554	15,004,683	15,278,823	16,855,488	17,131,340
Industrial	808,368	763,306	815,322	735,076	726,341
Subtotal-Retail	60,592,027	56,871,063	57,731,636	62,555,894	63,232,723
Transportation-Other	233,171,072	253,411,360	251,052,031	275,544,455	277,163,854
Total	293,763,099	310,282,423	308,783,667	338,100,349	340,396,577

III-E-20

Request:

Provide, for test year only, a schedule by tariff rates and by service classifications showing proposed increase and percent of increase.

Response:

Please see UGI Gas Exhibit E - Proof of Revenue and the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8.

Prepared by or under the supervision of: Sherry A. Epler

III-E-21

Request:

If a gas company is affiliated with another utility segment, such as a water or electric segment, explain the effects, if any, upon allocation factors used in the gas rate filing of current or recent rate increases allowed to the other utility segment (or segments) of the company.

Response:

UGI Utilities, Inc. owns both gas and electric divisions.

UGI Gas incurs costs for services provided by UGI Corp., and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. UGI also allocates or assigns costs between UGI Electric and UGI Gas. All costs which can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs which cannot be directly associated with the operation of an individual operating unit are allocated to the various companies benefiting from the service. Allocations are done by a methodology applicable to the cost (e.g., budgeted time allocations, number of employees, etc.) or, if no one methodology is specific to the cost, by a formula referred to as the Modified Wisconsin Formula ("MWF"). The MWF achieves an equitable distribution of common expenses based on the relative activity and size of each operating unit to the total of all operating units, which benefit from the respective activities. Activity is measured by total revenues and total operating expenses and size is measured by tangible net assets employed (excluding acquisition goodwill).

The proposed rates of UGI Gas are not based on any increase granted to any other affiliated utility segment.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-E-22

Request:

Provide supporting data detailing curtailment adjustments, procedures and policies.

Response:

The Company did not have any curtailment adjustments during the historic test year ending September 30, 2021, and is not claiming any curtailment adjustments in its future test year or fully projected future test year. In addition, the Company follows curtailment procedures and policies as specified in its Gas Tariffs on file with the Commission. Please refer to UGI Gas Exhibit F, Section 21, Gas Emergency Planning, of the Company's current tariff.

Prepared by or under the supervision of: Christopher R. Brown

III-E-23

Request:

Submit a schedule showing fuel cost in excess of base compared to fuel cost recovery for the period two months prior to test year and the test year.

Response:

There are no fuel costs in excess of base compared to fuel cost recovery.

All of the Company's fuel costs are recovered through its annual purchased gas cost filing made pursuant to Section 1307(f) of the Public Utility Code.

Prepared by or under the supervision of: Christopher R. Brown

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III-E-24

Request:

Supply a detailed analysis of Purchased Gas for the test year and the twelve month period prior to the test year.

Response:

Please refer to UGI Gas Docket No. R-2021-3025652 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filing which can be found at URL https://www.puc.pa.gov/docket/R-2021-3025652.

Prepared by or under the supervision of: Christopher R. Brown

III-E-25

Request:

Submit calculations supporting energy cost per MCF and operating ratio used to determine increase in costs other than production to serve additional load.

Response:

The energy cost per Mcf is developed as part of each annual and quarterly 1307(f) filing submitted to the Commission. Please refer to UGI Gas Docket No. R-2021-3025652 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filing which can be found at URL https://www.puc.pa.gov/docket/R-2021-3025652.

Prepared by or under the supervision of: Christopher R. Brown

III-E-26

Request:

Submit detailed calculations for bulk gas transmission service costs under supply and/or interconnection agreements.

Response:

UGI Gas incurs no bulk gas transmission costs under supply and/or interconnection agreements.

Prepared by or under the supervision of: Christopher R. Brown

III-E-27

Request:

Submit a schedule for gas producing units retired or scheduled for retirement subsequent to the test year showing station, units, MCF capacity, hours of operation during test year, net output produced and cents/MCF of maintenance and fuel expenses.

Response:

UGI Gas did not have any gas producing units retired or scheduled for retirement subsequent to the test year.

Prepared by or under the supervision of: Vivian K. Ressler

III-E-28

Request:

Provide a statement explaining the details of firm gas purchase (long-term) contracts with affiliated and nonaffiliated utilities, including determination of costs, terms of contract, and other pertinent information.

Response:

UGI Gas does not have any firm gas purchase (long-term) contracts with affiliated and nonaffiliated utilities.

Prepared by or under the supervision of: Christopher R. Brown

III-E-29

Request:

Provide intrastate operations percentages by expense categories for two years prior to the test year.

Response:

The majority of the operations of UGI Gas are intrastate. UGI Gas has a small percentage of operations in Maryland under the jurisdiction of the Maryland Public Service Commission. The allocation factor used to assign the costs to the Maryland operation is based on test year sales. Please see Attachment III-E-29.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Base Rate Case Expense Allocation
Sales (Mcf)

	Actual HTY (FY 21)	Budget FTY (FY 22)	Budget FPFTY (FY 23)
PA Volume	314,541,241	339,580,851	342,165,065
Maryland Volume	137,247	138,048	140,603
Maryland Allocation	0.044%	0.041%	0.041%
PA Allocation	99.956%	99.959%	99.959%

III-E-30

Request:

Provide a schedule showing suppliers, MCF purchased, cost (small purchases from independent suppliers may be grouped); emergency purchases, listing same information; curtailments during the year; gas put into and taken out of storage; line loss, and any other gas input or output not in the ordinary course of business.

Response:

Please refer to UGI Gas Docket No. R-2021-3025652 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filings which can be found at URL https://www.puc.pa.gov/pcdocs/1705894.pdf.

Prepared by or under the supervision of: Christopher R. Brown

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III-E-31

Request:

Provide a schedule showing the determination of the fuel costs included in the base cost of fuel.

Response:

Please refer to UGI Gas Docket No. R-2021-3025652 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filing which can be found at URL https://www.puc.pa.gov/docket/R-2021-3025652.

Prepared by or under the supervision of: Christopher R. Brown

III-E-32

Request:

Provide a schedule showing the calculation of any deferred fuel costs shown in Account 174. Also, explain the accounting, with supporting detail, for any associated income taxes.

Response:

Please see Attachment III-E-32.

Because the tax treatment for deferred fuel costs differs from the book treatment, deferred taxes are generated on the over or under-collection of deferred fuel costs. Specifically, tax follows a cash basis as it relates to deferred fuel costs. When the Company is in an over-collected position, a deferred tax asset is generated because the Company will recognize as taxable income and pay taxes currently on the cash it collected from customers, even though this is not recognized as book revenue. Vice versa, when the Company is in an under-collected position, a deferred tax liability is generated because the Company recognizes less taxable income because it did not collect adequate cash to cover its fuel costs, but for book purposes revenue is recognized such that no margin is recognized on the purchase of gas.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Statement of Total Over/Under Collections From the Present
Gas Cost Rate Adjustment Clause - 12 Months Ending September 30, 2021

	Sales Mcf (1)	PGC Revenue (2)	Cost of Fuel (3)	Over / (Under) Collections (4)
October	1,825,753	$ 7,876,738	$ 7,316,260	$ 560,477
November	3,325,060	$ 14,333,957	$ 25,243,548	$ (10,909,591)
December	7,705,175	$ 33,993,967	$ 41,256,414	$ (7,262,447)
January	10,537,536	$ 47,673,744	$ 44,983,599	$ 2,690,144
Februrary	10,899,017	$ 49,296,960	$ 50,430,371	$ (1,133,411)
March	10,676,000	$ 48,327,422	$ 38,340,395	$ 9,987,026
April	5,325,468	$ 24,161,124	$ 15,702,741	$ 8,458,383
May	2,989,566	$ 13,548,590	$ 11,705,960	$ 1,842,630
June	1,779,751	$ 8,143,749	$ 8,907,703	$ (763,955)
July	1,091,159	$ 5,075,314	$ 8,140,515	$ (3,065,201)
August	1,020,944	$ 4,745,701	$ 8,258,203	$ (3,512,502)
September	1,036,699	$ 5,168,211	$ 7,422,618	$ (2,254,407)
	58,212,126	$ 262,345,475	$ 267,708,329	$ (5,362,854)

III-E-33

Request:

Submit a schedule showing maintenance expenses, gross plant and the relation of maintenance expenses thereto as follows:

(i) Gas Production Maintenance Expenses per MCF production, per $1,000 MCF production, and per $1,000 of Gross Production Plant;

(ii) Transmission Maintenance Expenses per MMCF mile and per $1,000 of Gross Transmission Plant;

(iii) Distribution Maintenance Expenses per customer and per $1,000 of Gross Distribution Plant;

(iv) Storage Maintenance Expenses per MMCF of Storage Capacity and $1,000 of Gross Storage Plant. This schedule shall include three years prior to the test year, the test year and one year's projection beyond the test year.

Response:

Please see Attachment III-E-33.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
FOR THE YEARS ENDED SEPTEMBER 30, 2019 -2023

		12 MONTHS ENDED				
		9/30/19	9/30/20	9/30/21	9/30/22	9/30/23
(i)	Maintenance Exp /MCF Produced	-	-	-	-	-
	Maintenance Exp /$1,000 MCF	-	-	-	-	-
	Maintenance Exp /$1,000 GPP	-	-	-	-	-
(ii)	Trans. Main. Exp /MMCF	-	-	-	-	-
	Trans. Main. Exp /Transmission Mile	-	-	-	-	-
	Trans. Main. Exp /$1,000 GTP	-	-	-	-	-
(iii)	Dist. Main. Exp /Customer	48.16	44.49	45.96	48.49	50.33
	Dist. Main. Exp /$1,000 GDP	9.82	8.61	8.22	8.09	7.81
(iv)	Storage. Main. Exp /MMCF Capacity	-	-	-	-	-
	Storage. Main. Exp /$1,000 GSP	-	-	-	-	-

III-E-34

Request:

Prepare a 3-column schedule of expenses, as described below for the following periods (supply sub-accounts, if significant, to clarify basic accounts):

a. Column 1--Test Year

b. Column 2 and 3--The two previous years

Provide the annual recorded expense by accounts. (Identify all accounts used but not specifically listed below.)

Response:

Please see Attachment III-E-34.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2021, 2022 and 2023
($ in Thousands)

Title of Account	Account Number	2021	2022	2023
Manufactured Gas Production				
Operation Supervision and Engineering	710.0	-	-	-
Production Labor and Expenses				
Steam Expenses	711.0	-	-	-
Other Power Expenses	712.0	-	-	-
Coke Oven Expenses	713.0	-	-	-
Producer Gas Expenses	714.0	-	-	-
Water Gas Generating Expenses	715.0	-	-	-
Oil Gas Generating Expenses	716.0	-	-	-
Liquefied Petroleum Gas Expenses	717.0	-	-	-
Other Process Production Expenses	718.0	-	-	-
Total Production Labor and Expenses		-	-	-
Gas Fuels				
Fuel Under Coke Ovens	719.0	-	-	-
Producer Gas Fuel	720.0	-	-	-
Water Gas Generator Fuel	721.0	-	-	-
Fuel for Oil Gas	722.0	-	-	-
Fuel for Liquefied Petroleum Gas Process	723.0	-	-	-
Other Gas Fuels	724.0	-	-	-
Total Gas Fuels Expenses		-	-	-
Gas Raw Materials				
Coal Carbonized in Coke Ovens	725.0	-	-	-
Oil for Water Gas	726.0	-	-	-
Oil for Oil Gas	727.0	-	-	-
Liquefied Petroleum Gas Expenses	728.0	-	-	-
Raw Materials for Other Gas Processes	729.0	-	-	-
Residuals Expenses	730.0	-	-	-
Residuals Produced-Credit	731.0	-	-	-
Purification Expenses	732.0	-	-	-
Gas Mixing Expenses	733.0	-	-	-
Duplicate Charges-Credit	734.0	-	-	-
Miscellaneous Production Expenses	735.0	29	14	14
Rents	736.0	-	-	-
Total Gas Raw Materials Expenses		29	14	14
Maintenance				
Maintenance Supervision and Engineering	740.0	-	-	-
Maintenance of Structures and Improvements	741.0	-	-	-
Maintenance of Production Equipment	742.0	-	-	-
Total Maintenance Expenses		-	-	-
Manufactured Gas Production Expenses		29	14	14

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2021, 2022 and 2023
($ in Thousands)

NATURAL GAS PRODUCTION EXPENSES				
Production and Gathering				
Operation				
Operating Supervision and Engineering	750.0	-	-	-
Production Maps and Records	751.0	-	-	-
Gas Wells Expenses	752.0	-	-	-
Field Lines Expenses	753.0	-	-	-
Field Compressor Station Expenses	754.0	-	-	-
Field Compressor Station Fuel and Power	755.0	-	-	-
Field Measuring and Regulating Station Expenses	756.0	-	-	-
Purification Expenses	757.0	-	-	-
Gas Well Royalties	758.0	-	-	-
Other Expenses	759.0	-	-	-
Rents	760.0	-	-	-
Total Production & Gathering Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	761.0	-	-	-
Maintenance of Structures and Improvements	762.0	-	-	-
Maintenance of Producing Gas Wells	763.0	-	-	-
Maintenance of Field Lines	764.0	-	-	-
Maintenance of Field Compressor Station Equipment	765.0	-	-	-
Maintenance of Field Measuring and Reg. Station Equip.	766.0	-	-	-
Maintenance of Purification Equipment	767.0	-	-	-
Maintenance of Drilling and Cleaning Equipment	768.0	-	-	-
Maintenance of Other Equipment	769.0	-	-	-
Total Production & Gathering Maintenance Expenses		-	-	-
Products Extraction				
Operation				
Operation Supervision and Engineering	770.0	-	-	-
Operating Labor	771.0	-	-	-
Gas Shrinkage	772.0	-	-	-
Fuel	773.0	-	-	-
Power	774.0	-	-	-
Materials	775.0	-	-	-
Operation Supplies and Expenses	776.0	-	-	-
Gas Processed by Others	777.0	-	-	-
Royalties on Products Extracted	778.0	-	-	-
Marketing Expenses	779.0	-	-	-
Products Purchased for Resale	780.0	-	-	-
Variation in Products Inventory	781.0	-	-	-
Extracted Products Used by the Utility-Credit	782.0	-	-	-
Rents	783.0	-	-	-
Total Products Extraction Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	784.0	-	-	-
Maintenance of Structures and Improvements	785.0	-	-	-
Maintenance of Extraction and Refining Equipment	786.0	-	-	-
Maintenance of Pipe Lines	787.0	-	-	-
Maintenance of Extracted Products Storage Equipment	788.0	-	-	-
Maintenance of Compressor Equipment	789.0	-	-	-
Maintenance of Gas Measuring & Regulating Equipment	790.0	-	-	-
Maintenance of Other Equipment	791.0	-	-	-
Total Products Extraction Maintenance Expenses		-	-	-
Total Natural Gas Production Expenses		-	-	-

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2021, 2022 and 2023
($ in Thousands)

EXPLORATION AND DEVELOPMENT EXPENSES				
Operation				
Delay Rentals	795.0	-	-	-
Nonproductive Well Drilling	796.0	-	-	-
Abandoned Leases	797.0	-	-	-
Other Exploration	798.0	-	-	-
Total Exploration and Development Operation Exp.		-	-	-
OTHER GAS SUPPLY EXPENSES				
Operation				
Natural Gas Well Head Purchases	800.0	-	-	-
Natural Gas Well Head Purchases, Intercompany Trans.	801.0	-	-	-
Natural Gas Gasoline Plant Outlet Purchases	802.0	-	-	-
Natural Gas Transmission Line Purchases	803.0	-	-	-
Natural Gas City Gate Purchases	804.0	357,994	371,506	371,499
Liquefied Natural Gas Purchases	804.1	163	-	-
Other Gas Purchases	805.0	542	82	82
Purchases Gas Cost Adjustments	805.1	(83,606)	(29,104)	(16,942)
Exchange Gas	806.0	-	-	-
Purchased Gas Expenses	807.0	-	-	-
Gas Withdrawn from Storage-Debit	808.1	26,406	31,278	31,278
Gas Delivered to Storage-Credit	808.2	(44,991)	(27,988)	(27,988)
Withdrawals of Liquefied Nat. Gas Held for Processing	809.1	-	-	-
Deliveries of Natural Gas for Processing	809.2	-	-	-
Gas Used for Compressor Station Fuel-Credit	810.0	-	-	-
Gas Used for Products Extraction-Credit	811.0	-	-	-
Gas Used for Other Utility Operations-Credit	812.0	(928)	-	-
Other Gas Supply Expenses	813.0	6,895	353	357
Gas Supply Operation Expenses		262,475	346,127	358,286
Natural Gas Storage, Terminating & Processing Exp.				
Underground Storage Expenses				
Operation Supervision and Engineering	814.0	-	-	-
Maps and Records	815.0	-	-	-
Wells Expenses	816.0	-	-	-
Lines Expenses	817.0	-	-	-
Compressor Station Expenses	818.0	-	-	-
Compressor Station Fuel and Power	819.0	-	-	-
Measuring and Regulating Station Expenses	820.0	-	-	-
Purification Expenses	821.0	-	-	-
Exploration and Development	822.0	-	-	-
Gas Losses	823.0	-	-	-
Other Expenses	824.0	-	-	-
Storage Well Royalties	825.0	-	-	-
Rents	826.0	-	-	-
Total Underground Storage Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	830.0	-	-	-
Maintenance of Structures and Improvements	831.0	-	-	-
Maintenance of Reservoirs and Wells	832.0	-	-	-
Maintenance of Lines	833.0	-	-	-
Maintenance of Compressor Station Equipment	834.0	-	-	-
Maintenance of Measuring & Regulating Station Equip.	835.0	-	-	-
Maintenance of Purification Equipment	836.0	-	-	-
Maintenance of Other Equipment	837.0	-	-	-
Total Underground Maintenance Expenses		-	-	-

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2021, 2022 and 2023
($ in Thousands)

Other Storage Expenses				
Operation				
Operating Supervision and Engineering	840.0	-	-	-
Operation Labor and Expenses	841.0	-	-	-
Rents	842.0	-	-	-
Fuel	842.1	-	-	-
Power	842.2	-	-	-
Gas Losses	842.3	-	-	-
Storage Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	843.1	-	-	-
Maintenance of Structures and Improvements	843.2	-	-	-
Maintenance of Gas Holders	843.3	-	-	-
Maintenance of Purification Equipment	843.4	-	-	-
Maintenance of Liquefaction Equipment	843.5	-	-	-
Maintenance of Vaporizing Equipment	843.6	-	-	-
Maintenance of Compressor Equipment	843.7	-	-	-
Maintenance of Measuring and Regulatory Equipment	843.8	-	-	-
Maintenance of Other Equipment	843.9	-	-	-
Storage Maintenance Expenses		-	-	-
LIQUEFIED NATURAL GAS TERMINATING AND PROCESSING EXPENSES				
Operation				
Operation Supervision and Engineering	844.1	-	-	-
LNG Processing Terminal Labor and Expenses	844.2	-	-	-
Liquefaction Processing Labor and Expenses	844.3	-	-	-
LNG Transportation Labor and Expenses	844.4	-	-	-
Measuring and Regulating Labor and Expenses	844.5	-	-	-
Compressor Station Labor and Expenses	844.6	-	-	-
Communication System Expenses	844.7	-	-	-
System Control and Load Dispatching	844.8	-	-	-
Fuel	845.1	-	-	-
Power	845.2	-	-	-
Rents	845.3	-	-	-
Demurrage Charges	845.4	-	-	-
Warfare Receipts-Credit	845.5	-	-	-
Processing Liquefied or Vaporized Gas by Others	845.6	-	-	-
Gas Losses	846.1	-	-	-
Other Expenses	846.2	-	-	-
Total Liq. N.G. Term & Proc. Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	847.1	-	-	-
Maintenance of Structures and Improvements	847.2	-	-	-
Maintenance of LNG Processing Terminal Equipment	847.3	-	-	-
Maintenance of LNG Transportation Equipment	847.4	-	-	-
Maintenance of Measuring and Regulating Equipment	847.5	-	-	-
Maintenance of Compressor Station Equipment	847.6	-	-	-
Maintenance of Communication Equipment	847.7	-	-	-
Maintenance of Other Equipment	847.8	-	-	-
Total Liq. N.G. Term. Proc. Maintenance Expenses		-	-	-

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2021, 2022 and 2023
($ in Thousands)

TRANSMISSION EXPENSES				
Operation				
Operating Supervision and Engineering	850.0	-	-	-
System Control and Load Dispatching	851.0	-	-	-
Communication System Expenses	852.0	-	-	-
Compressor Station Labor and Expenses	853.0	-	-	-
Gas for Compressor Station Fuel	854.0	-	-	-
Other Fuel and Power for Compressor Stations	855.0	-	-	-
Mains Expenses	856.0	-	-	-
Measuring and Regulating Station Expenses	857.0	-	-	-
Transmission and Compression of gas by Others	858.0	-	-	-
Other Expenses	859.0	-	-	-
Rents	860.0	-	-	-
Total Transmission Operation Expenses		-	-	-
Maintenance				
Maintenance Supervision and Engineering	861.0	-	-	-
Maintenance of Structures and Improvements	862.0	-	-	-
Maintenance of Mains	863.0	-	-	-
Maintenance of Compressor Station Equipment	864.0	-	-	-
Maintenance of Measuring and Regulating Station Equip.	865.0	-	-	-
Maintenance of Communication Equipment	866.0	-	-	-
Maintenance of Other Equipment	867.0	-	-	-
Total Transmission Maintenance Expenses		-	-	-
DISTRIBUTION EXPENSES				
Operations Expense				
Operation Supervision and Engineering	870.0	7,120	3,317	3,415
Distribution Load Dispatching	871.0	42	2	2
Compressor Station Labor and Expenses	872.0	-	-	-
Compressor Station Fuel and Power (Major Only)	873.0	-	-	-
Mains and Services Expenses	874.0	21,479	25,175	27,345
Measuring and Regulating Station Expenses-General	875.0	1,384	4,065	4,188
Measuring and Regulating Station Expenses-Industrial	876.0	38	13	12
Measuring and Regulating Station Expenses-City Gate	877.0	275	111	114
Meter and House Regulator Expenses	878.0	3,331	3,078	3,204
Customer Installations Expenses	879.0	2,035	2,663	2,721
Other Expenses	880.0	1,482	1,245	1,281
Rents	881.0	4,074	3,032	3,117
Total Distribution Operation Expenses		41,260	42,701	45,399
Maintenance Expense				
Maintenance Supervision and Engineering	885.0	2,292	495	509
Maintenance of Structures and Improvements	886.0	-	-	-
Maintenance of Mains	887.0	13,726	26,984	28,149
Maintenance of Compressor Station Equipment	888.0	-	-	262
Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	1,789	2,771	3,144
Maintenance of Measuring & Reg. Station Equip.-Indtrl.	890.0	3,242	4,556	4,686
Maintenance of Measuring & Reg. Station Equip.-City G	891.0	113	372	121
Maintenance of Services	892.0	936	1,499	1,547
Maintenance of Meters & House Regulators	893.0	(2)	-	-
Maintenance of Other Equipment	894.0	340	548	552
Construction & Maintenance	895.0	-	-	-
Total Distribution Maintenance Expenses		22,436	37,225	38,970

UGI Utilities, Inc. - Gas Division
Statement of Operation and Maintenance Expenses
12-Months Ended September 30, 2021, 2022 and 2023
($ in Thousands)

CUSTOMER ACCOUNTS EXPENSES				
Operations				
Supervision	901.0	477	799	824
Meter Reading Expenses	902.0	2,739	2,112	2,177
Customer Records & Collection Expenses	903.0	36,332	34,943	35,342
Uncollectable Accounts	904.0	11,927	11,845	14,419
Miscellaneous Customer Accounts Expenses	905.0	1,790	2,143	2,198
Customer Account Operations Expenses		53,265	51,842	54,960
CUSTOMER SERVICE & INFORM. EXPENSES				
Operations				
Supervision	907.0	158	167	172
Customer Assistance Expenses	908.0	938	870	896
Informational & Instructional Advertising Expenses	909.0	-	-	-
Miscellaneous Customer Service & Informational Exp.	910.0	9,170	9,183	9,300
Total Cust. Service & Inform. Operations Exp		10,266	10,220	10,368
SALES EXPENSES				
Operation				
Supervision	911.0	107	414	426
Demonstrating and Selling Expenses	912.0	617	(612)	(596)
Advertising Expenses	913.0	1,210	1,587	1,637
(Reserved)	914.0	-	-	-
(Reserved)	915.0	-	-	-
Miscellaneous Sales Expenses	916.0	127	249	258
Total Operation Sales Expenses		2,061	1,638	1,725
ADMINISTRATIVE AND GENERAL EXPENSES				
Operation				
Administrative and General Salaries	920.0	17,549	33,895	35,612
Office Supplies and Expenses	921.0	17,569	20,600	21,222
Administrative Expenses Transferred-Credit	922.0	-	-	-
Outside Service Employed	923.0	36,517	24,151	25,611
Property Insurance	924.0	360	-	-
Injuries and Damages	925.0	7,126	10,317	11,027
Employee Pensions and Benefits	926.0	25,058	13,188	13,723
Franchise Requirements	927.0	-	-	-
Regulatory Commission Expenses	928.0	772	394	1,138
Duplicate Charges-Credit	929.0	-	-	-
General Advertising Expenses	930.1	-	280	288
Miscellaneous General Expenses	930.2	2,239	2,642	2,728
Rents	931.0	21	37	38
Total A & G Operation Expenses		107,211	105,504	111,387
Maintenance				
A&G Maintenance of General Plant	932.0	600	4,255	4,394
A&G Maintenance of General Plant	935.0	-	255	263
Total A&G Maintenance Expenses		600	4,510	4,657
Total Gas Operation and Maintenance Expenses		$ 499,603	$ 599,781	$ 625,766
Total Gas Operation Expenses		$ 476,567	$ 558,046	$ 582,139
Total Gas Maintenance Expenses		23,036	41,735	43,627
Total Gas Operation and Maintenance Expenses		$ 499,603	$ 599,781	$ 625,766

III-E-35

Request:

Submit a schedule showing the Gross Receipts Tax Base used in computing Pennsylvania Gross Receipts Tax Adjustment.

Response:

Not applicable. UGI Gas is not subject to the Pennsylvania Gross Receipts Tax.

Prepared by or under the supervision of: Nicole M. McKinney

III-E-36

Request:

State the amount of gas, in mcf, obtained through various suppliers in past years.

Response:

Please see Book I, Attachment 1-A-1 of the 2021 1307(f) Purchased Gas Cost filing for UGI Gas at Docket No. R-2021-3025652 which can be found at URL https://www.puc.pa.gov/pcdocs/1702100.pdf.

Prepared by or under the supervision of: Christopher R. Brown

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III-E-37

Request:

In determining pro forma expense, exclude cost of gas adjustments applicable to fuel adjustment clause and exclude fuel adjustment clause revenues, so that the operating statement is on the basis of base rates only.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Schedule D-6.

Prepared by or under the supervision of: Tracy A. Hazenstab

III-E-38

Request:

Identify company's policy with respect to replacing customers lost through attrition.

Response:

The Company actively seeks opportunities to add new customers including new construction and conversion customers and adds these customers to the extent they meet the requirements of the Company's Tariff.

Prepared by or under the supervision of: Christopher R. Brown

III-E-39

Request:

Identify procedures developed to govern relationship between the respondent and potential customers--i.e., basically expansion, alternate energy requirements, availability of supply, availability of distribution facilities, ownership of metering and related facilities.

Response:

Please refer to UGI Gas Exhibit F, Rule 5, Extension Regulation, of the current tariff for UGI Utilities, Inc. - Gas Division.

Please refer to UGI Gas Exhibit F, Rule 5, Extension Regulation, of the proposed tariff supplement for UGI Utilities, Inc. - Gas Division.

Prepared by or under the supervision of: Christopher R. Brown

SECTION 53.53 – RATE STRUCTURE

IV-B-1

Request:

Provide a Cost of Service Study showing the rate of return under the present and proposed tariffs for all customer classifications. The study should include a summary of the allocated measures of value, operating revenues, operating expenses and net return for each of the customer classifications at original cost and at the 5-year trended original cost.

a. (Reserved)

Response:

Please refer to UGI Gas Exhibit D.

Prepared by or under the supervision of: Constance E. Heppenstall

IV-B-2

Request:

Provide a statement of testimony describing the complete methodology of the cost of service study.

Response:

Please refer to the Direct Testimony of Constance E. Heppenstall, UGI Gas Statement No. 10.

Prepared by or under the supervision of: Constance E. Heppenstall

IV-B-3

Request:

Provide a complete description and back-up calculations for all allocation factors.

Response:

Please see UGI Gas Exhibit D.

Prepared by or under the supervision of: Constance E. Heppenstall

IV-B-4

Request:

Provide an exhibit for each customer classification showing the following data for the test year and the four previous years:

a. The maximum coincident peak day demand.

b. The maximum coincident 3-day peak day demand.

c. The average monthly consumption in MCF during the Primary Heating Season (November-March).

d. The average monthly consumption in MCF during the Non-heating season (April-October).

e. The average daily consumption in MCF for each 12-month period.

Response:

Please see Attachments IV-B-4 (a)-(e).

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Coincident Peak Day Demand

Winter Season	Peak Day Date	Volume (Mdth)
2020-2021	1/28/2021	1,531.0
2019-2020	2/14/2020	1,564.5
2018-2019	3/6/2019	1,626.5
2017-2018	1/5/2018	1,420.9
2016-2017	12/15/2016	1,407.9

UGI UTILITIES, INC. - GAS DIVISION
COINCIDENT 3 DAY PEAK PERIODS
SENDOUT BY RATE CLASS

	2016-2017			2017-2018			2018-2019			2019-2020			2020-2021		
	JAN 6	JAN 7	JAN 8	JAN 4	JAN 5	JAN 6	MAR 5	MAR 6	MAR 7	FEB 14	FEB 15	FEB 16	JAN 27	JAN 28	JAN 29
	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)	(MDTH)
RG	3.4	4.0	4.4	3.3	3.8	3.9	2.8	3.1	2.6	2.8	2.4	1.9	2.2	2.8	2.9
RH	337.6	391.6	428.5	414.3	477.5	487.4	358.4	398.5	343.8	400.2	335.0	262.6	290.9	375.1	387.4
CG	4.9	5.7	6.2	5.1	5.9	6.0	5.8	6.4	5.5	7.8	6.6	5.1	3.1	4.0	4.1
CH	136.1	157.8	172.7	158.4	183.1	186.8	136.5	151.7	130.7	166.1	139.0	108.9	105.5	136.1	140.5
IG	1.7	1.8	2.0	1.7	2.2	2.2	1.4	1.6	1.3	2.2	1.8	1.4	0.8	1.1	1.1
IH	6.9	8.1	8.9	6.2	7.2	7.3	5.9	6.6	5.6	8.2	6.8	5.4	4.9	6.4	6.6
PGC FIRM	490.7	569.1	622.6	589.1	679.7	693.6	510.8	567.9	489.6	587.3	491.6	385.3	407.5	525.4	542.6
RT (CHOICE)	25.3	25.2	25.2	43.0	43.0	42.9	36.4	36.0	35.6	33.2	32.9	32.9	43.4	43.8	44.0
NT (CHOICE)	62.7	62.6	62.6	79.9	79.8	79.8	72.7	71.9	71.3	70.7	69.9	69.9	78.7	79.3	79.7
DS	77.2	87.0	97.5	89.6	97.5	100.2	85.2	93.3	80.4	57.4	49.7	47.2	56.8	65.8	64.3
LFD	87.3	81.7	90.5	108.1	106.3	97.3	102.6	105.2	99.8	77.2	62.0	62.5	100.0	105.4	97.5
XD-F/CDS-F	306.6	277.9	240.3	281.9	296.2	285.7	496.7	515.7	505.5	514.8	493.2	485.1	532.1	554.7	519.3
FIRM TRANSPORTATION	559.1	534.4	516.1	602.5	622.9	605.9	793.6	822.2	792.6	753.3	707.7	697.6	810.9	849.0	804.8
INTERRUPTIBLE	219.7	134.8	145.3	133.5	118.4	113.5	232.7	236.5	239.0	223.9	215.6	210.9	154.8	156.5	109.8
TOTAL	1,269.4	1,238.4	1,284.0	1,325.1	1,420.9	1,412.9	1,537.0	1,626.5	1,521.1	1,564.5	1,414.8	1,293.7	1,373.2	1,531.0	1,457.2

UGI Utilities, Inc. - Gas Division

Average Monthly Consumption in MCF during Primary Heating Season (November-March)

	Rate R Residential-Non Htg	Rate R Residential-Htg	Rate RT RT Total	Rate N Commercial-Non Htg	Rate CIAC Commercial-AC	Rate N Commercial-Htg	Rate N Industrial-Non Htg	Rate N Industrial-Htg	Rate NT NT Total	Rate DS DS Total	Rate LFD,XD,IS Large Transp-Other
2017	56,564	6,127,398	610,795	79,748	(20)	2,142,054	23,042	104,525	1,492,102	1,363,001	14,160,748
2018	51,373	6,847,249	943,620	87,121	0	2,442,351	33,691	111,879	1,761,123	1,508,339	14,341,332
2019	52,269	6,800,430	1,041,657	94,622	0	2,547,463	21,162	110,578	1,873,434	1,485,246	16,330,315
2020	45,269	6,029,521	908,977	94,500	0	2,296,570	19,074	102,565	1,706,718	1,258,135	19,658,417
2021	48,043	6,386,277	974,183	76,612	0	2,262,056	16,769	107,176	1,764,937	1,223,098	19,188,476

UGI Utilities, Inc. - Gas Division

Average Monthly Consumption in MCF during the Non-Heating Season (April-October)

	Rate R Residential- Non Htg	Rate R Residential- Htg	Rate RT Total RT	Rate N Commercial- Non Htg	Rate CIAC Commercial- AC	Rate N Commercial- Htg	Rate N Industrial- Non Htg	Rate N Industrial- Htg	Rate NT Total NT	Rate DS Total DS	Rate LFD,XD,IS Large Transp-Other
2017	30,984	1,342,939	116,752	57,939	0	463,887	3,936	12,770	431,791	459,961	12,991,440
2018	26,451	1,456,287	216,923	51,095	0	570,574	7,057	21,233	550,230	591,322	14,945,472
2019	23,309	1,276,400	176,025	48,466	0	452,338	6,274	14,383	505,893	513,027	17,626,787
2020	25,529	1,531,436	249,985	38,555	0	386,867	2,644	19,825	521,045	392,029	18,400,940
2021	20,964	1,245,344	183,396	41,468	0	465,191	6,678	23,824	521,574	380,139	17,574,725

UGI Utilities, Inc. - Gas Division
Average Daily Consumption in MCF for each 12-Month period

	Rate R Residential- Non Htg	Rate R Residential- Htg	Rate RT Total RT	Rate N Commercial- Non Htg	Rate CIAC Commercial- AC	Rate N Commercial- Htg	Rate N Industrial- Non Htg	Rate N Industrial- Htg	Rate NT Total NT	Rate DS Total DS	Rate LFD,XD,IS Large Transp-Other
2017	1,352	110,893	10,820	2,147	2	38,354	391	1,691	28,854	27,516	445,168
2018	1,238	119,596	16,430	2,181	0	43,676	600	1,897	33,950	29,985	473,355
2019	1,181	119,543	17,932	2,255	0	44,115	408	1,823	35,731	32,139	556,241
2020	1,100	111,499	17,174	2,051	0	39,053	321	1,770	33,354	24,541	619,133
2021	1,074	112,989	17,117	1,836	0	40,020	352	1,881	34,281	24,607	611,734

IV-B-5

Request:

Submit a Bill Frequency Analysis for each rate. The analysis should include the rate schedule and block interval, the number of bills at each interval, the cumulative number of bills at each interval, the Mcf or therms at each interval, the cumulative Mcf or therms at each interval, the accumulation of Mcf or therms passing through each interval, and the revenue at each interval for both the present rate and the proposed rates. The Analysis should show only those revenues collected from the basic tariff.

Response:

Please see Attachment IV-B-5 provided on USB flash drive.

Prepared by or under the supervision of: Sherry A. Epler

IV-B-6

Request:

Supply copies of all present and proposed Gas Tariffs.

Response:

Please see UGI Gas Exhibit F - Current Tariff and UGI Gas Exhibit F - Proposed Tariff Supplement.

Prepared by or under the supervision of: Tracy A. Hazenstab

IV-B-7

Request:

Supply a graph of present and proposed base rates on hyperbolic cross section paper.

Response:

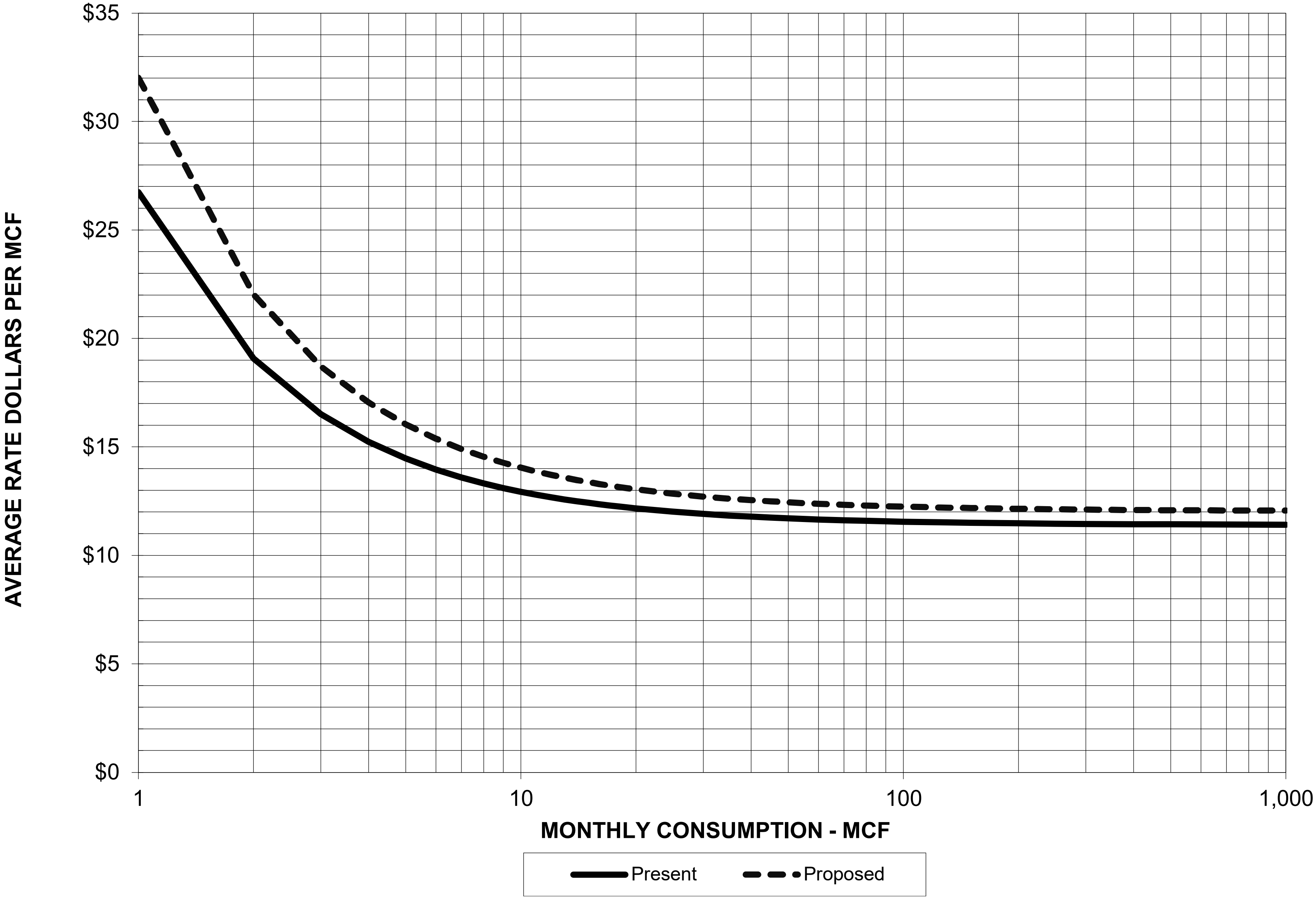
Please see Attachment IV-B-7.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Residential Service - Rate Schedule R
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 15.35	$ 19.97	$ 4.62	30.1%
1	$ 26.75	$ 32.02	$ 5.27	19.7%
2	$ 38.15	$ 44.07	$ 5.92	15.5%
3	$ 49.55	$ 56.12	$ 6.57	13.3%
4	$ 60.94	$ 68.17	$ 7.23	11.9%
5	$ 72.34	$ 80.22	$ 7.88	10.9%
6	$ 83.74	$ 92.26	$ 8.53	10.2%
7	$ 95.13	$ 104.31	$ 9.18	9.7%
8	$ 106.53	$ 116.36	$ 9.83	9.2%
9	$ 117.93	$ 128.41	$ 10.48	8.9%
10	$ 129.32	$ 140.46	$ 11.14	8.6%
11	$ 140.72	$ 152.51	$ 11.79	8.4%
12	$ 152.12	$ 164.56	$ 12.44	8.2%
13	$ 163.52	$ 176.61	$ 13.09	8.0%
14	$ 174.91	$ 188.65	$ 13.74	7.9%
15	$ 186.31	$ 200.70	$ 14.39	7.7%
16	$ 197.71	$ 212.75	$ 15.05	7.6%
17	$ 209.10	$ 224.80	$ 15.70	7.5%
18	$ 220.50	$ 236.85	$ 16.35	7.4%
19	$ 231.90	$ 248.90	$ 17.00	7.3%
20	$ 243.29	$ 260.95	$ 17.65	7.3%
25	$ 300.28	$ 321.19	$ 20.91	7.0%
30	$ 357.26	$ 381.43	$ 24.17	6.8%
35	$ 414.25	$ 441.68	$ 27.43	6.6%
40	$ 471.24	$ 501.92	$ 30.68	6.5%
45	$ 528.22	$ 562.16	$ 33.94	6.4%
50	$ 585.21	$ 622.41	$ 37.20	6.4%
60	$ 699.18	$ 742.89	$ 43.72	6.3%
70	$ 813.15	$ 863.38	$ 50.23	6.2%
80	$ 927.12	$ 983.87	$ 56.75	6.1%
90	$ 1,041.09	$ 1,104.35	$ 63.27	6.1%
100	$ 1,155.06	$ 1,224.84	$ 69.78	6.0%
125	$ 1,439.98	$ 1,526.06	$ 86.08	6.0%
150	$ 1,724.91	$ 1,827.28	$ 102.37	5.9%
200	$ 2,294.76	$ 2,429.71	$ 134.95	5.9%
250	$ 2,864.61	$ 3,032.14	$ 167.53	5.8%
300	$ 3,434.46	$ 3,634.58	$ 200.11	5.8%
400	$ 4,574.17	$ 4,839.45	$ 265.28	5.8%
500	$ 5,713.87	$ 6,044.31	$ 330.44	5.8%
1,000	$ 11,412.38	$ 12,068.65	$ 656.27	5.8%

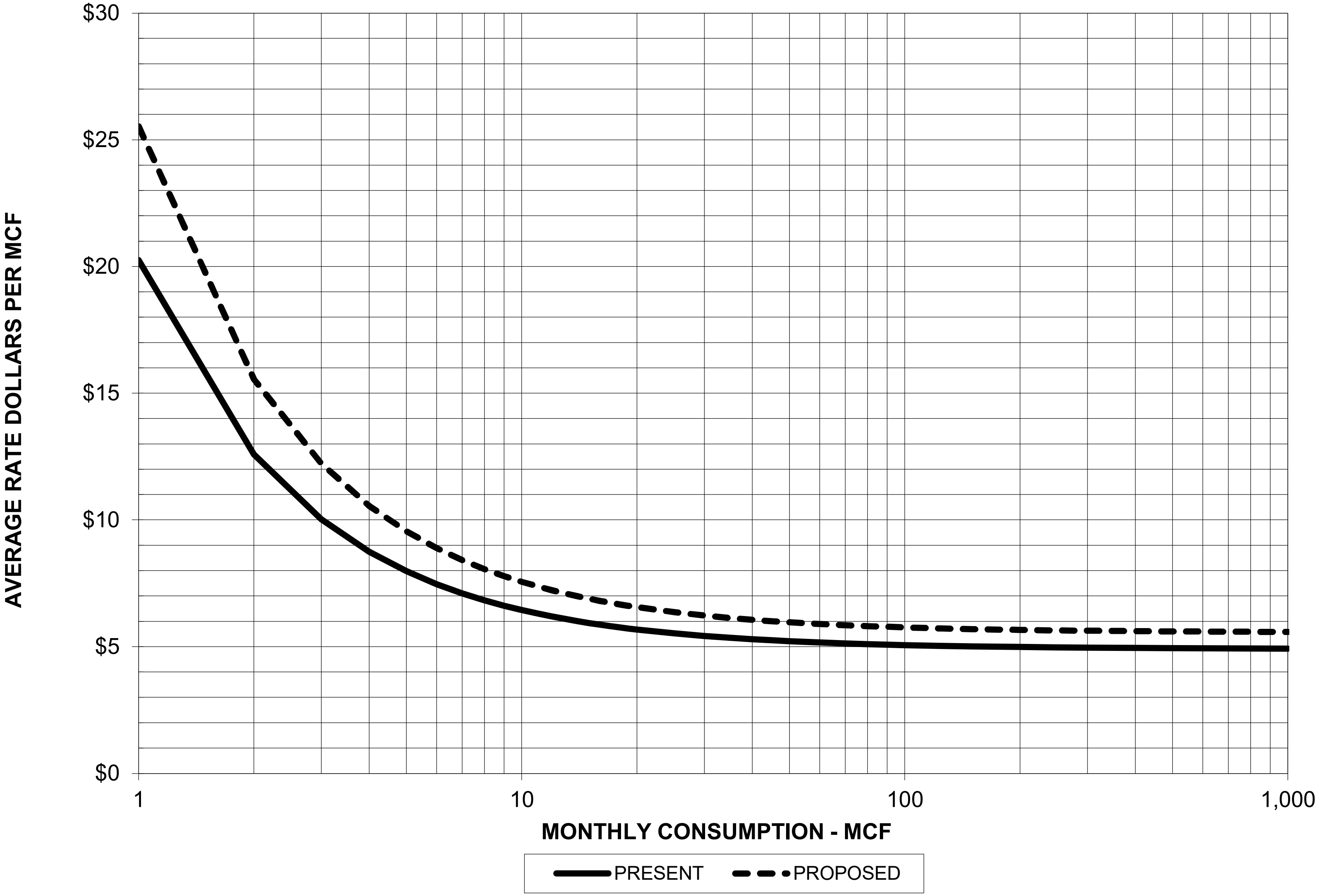
UGI Utilities, Inc.- Gas Division
Comparison of Present and Proposed Rates
Rate Schedule R



UGI Utilities, Inc. - Gas Division
Residential Transportation Service - Rate Schedule RT
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 15.35	$ 19.97	$ 4.62	30.1%
1	$ 20.26	$ 25.54	$ 5.27	26.0%
2	$ 25.17	$ 31.10	$ 5.93	23.6%
3	$ 30.08	$ 36.66	$ 6.59	21.9%
4	$ 34.99	$ 42.23	$ 7.24	20.7%
5	$ 39.89	$ 47.79	$ 7.90	19.8%
6	$ 44.80	$ 53.35	$ 8.55	19.1%
7	$ 49.71	$ 58.92	$ 9.21	18.5%
8	$ 54.62	$ 64.48	$ 9.86	18.1%
9	$ 59.53	$ 70.04	$ 10.52	17.7%
10	$ 64.43	$ 75.61	$ 11.17	17.3%
11	$ 69.34	$ 81.17	$ 11.83	17.1%
12	$ 74.25	$ 86.73	$ 12.48	16.8%
13	$ 79.16	$ 92.30	$ 13.14	16.6%
14	$ 84.07	$ 97.86	$ 13.80	16.4%
15	$ 88.97	$ 103.43	$ 14.45	16.2%
16	$ 93.88	$ 108.99	$ 15.11	16.1%
17	$ 98.79	$ 114.55	$ 15.76	16.0%
18	$ 103.70	$ 120.12	$ 16.42	15.8%
19	$ 108.61	$ 125.68	$ 17.07	15.7%
20	$ 113.51	$ 131.24	$ 17.73	15.6%
25	$ 138.05	$ 159.06	$ 21.01	15.2%
30	$ 162.59	$ 186.88	$ 24.28	14.9%
35	$ 187.13	$ 214.70	$ 27.56	14.7%
40	$ 211.67	$ 242.51	$ 30.84	14.6%
45	$ 236.21	$ 270.33	$ 34.12	14.4%
50	$ 260.75	$ 298.15	$ 37.39	14.3%
60	$ 309.83	$ 353.78	$ 43.95	14.2%
70	$ 358.92	$ 409.42	$ 50.50	14.1%
80	$ 408.00	$ 465.05	$ 57.06	14.0%
90	$ 457.08	$ 520.69	$ 63.61	13.9%
100	$ 506.16	$ 576.32	$ 70.17	13.9%
125	$ 628.86	$ 715.41	$ 86.55	13.8%
150	$ 751.56	$ 854.50	$ 102.94	13.7%
200	$ 996.96	$ 1,132.67	$ 135.72	13.6%
250	$ 1,242.36	$ 1,410.85	$ 168.49	13.6%
300	$ 1,487.76	$ 1,689.02	$ 201.26	13.5%
400	$ 1,978.56	$ 2,245.37	$ 266.81	13.5%
500	$ 2,469.36	$ 2,801.72	$ 332.36	13.5%
1,000	$ 4,923.37	$ 5,583.47	$ 660.10	13.4%

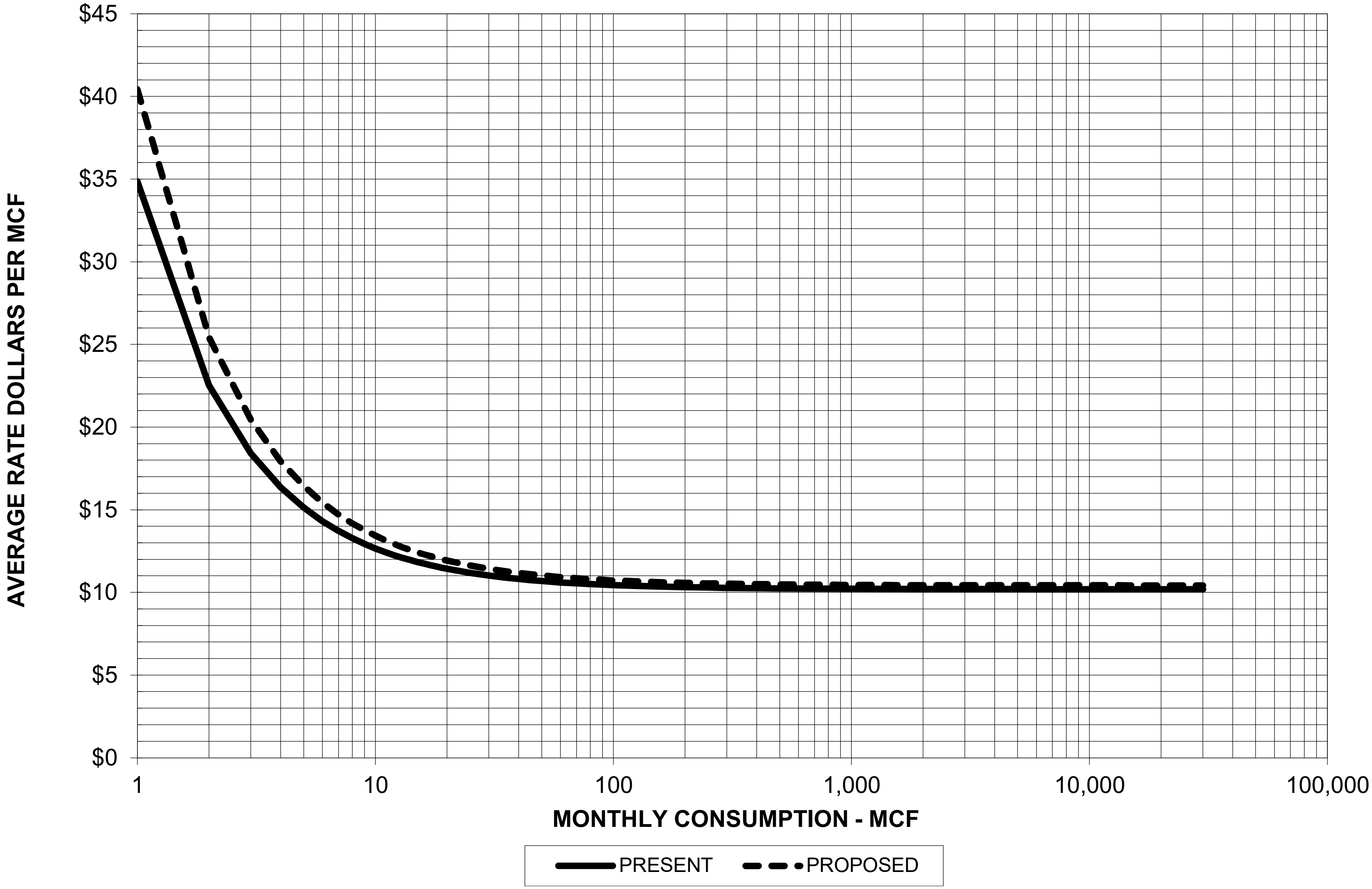
UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule RT



UGI Utilities, Inc. - Gas Division, Former South & Central Rate Districts
Non-Residential Service - Rate Schedule N
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 24.68	$ 30.00	$ 5.33	21.6%
1	$ 34.87	$ 40.43	$ 5.56	16.0%
2	$ 45.06	$ 50.86	$ 5.80	12.9%
3	$ 55.26	$ 61.30	$ 6.04	10.9%
4	$ 65.45	$ 71.73	$ 6.28	9.6%
5	$ 75.65	$ 82.16	$ 6.51	8.6%
6	$ 85.84	$ 92.59	$ 6.75	7.9%
7	$ 96.04	$ 103.02	$ 6.99	7.3%
8	$ 106.23	$ 113.46	$ 7.23	6.8%
9	$ 116.42	$ 123.89	$ 7.46	6.4%
10	$ 126.62	$ 134.32	$ 7.70	6.1%
11	$ 136.81	$ 144.75	$ 7.94	5.8%
12	$ 147.01	$ 155.18	$ 8.18	5.6%
13	$ 157.20	$ 165.62	$ 8.41	5.4%
14	$ 167.40	$ 176.05	$ 8.65	5.2%
15	$ 177.59	$ 186.48	$ 8.89	5.0%
16	$ 187.78	$ 196.91	$ 9.13	4.9%
17	$ 197.98	$ 207.34	$ 9.37	4.7%
18	$ 208.17	$ 217.78	$ 9.60	4.6%
19	$ 218.37	$ 228.21	$ 9.84	4.5%
20	$ 228.56	$ 238.64	$ 10.08	4.4%
25	$ 279.53	$ 290.80	$ 11.27	4.0%
30	$ 330.50	$ 342.96	$ 12.46	3.8%
35	$ 381.48	$ 395.12	$ 13.64	3.6%
40	$ 432.45	$ 447.28	$ 14.83	3.4%
45	$ 483.42	$ 499.44	$ 16.02	3.3%
50	$ 534.39	$ 551.60	$ 17.21	3.2%
60	$ 636.33	$ 655.92	$ 19.59	3.1%
70	$ 738.28	$ 760.24	$ 21.96	3.0%
80	$ 840.22	$ 864.56	$ 24.34	2.9%
90	$ 942.16	$ 968.88	$ 26.72	2.8%
100	$ 1,044.11	$ 1,073.20	$ 29.09	2.8%
125	$ 1,298.97	$ 1,334.00	$ 35.04	2.7%
150	$ 1,553.82	$ 1,594.80	$ 40.98	2.6%
200	$ 2,063.54	$ 2,116.40	$ 52.86	2.6%
250	$ 2,573.26	$ 2,638.00	$ 64.75	2.5%
300	$ 3,082.97	$ 3,159.61	$ 76.63	2.5%
400	$ 4,102.41	$ 4,202.81	$ 100.40	2.4%
500	$ 5,121.84	$ 5,246.01	$ 124.17	2.4%
1,000	$ 10,219.00	$ 10,462.02	$ 243.01	2.4%
2,000	$ 20,413.33	$ 20,894.03	$ 480.70	2.4%
3,000	$ 30,607.66	$ 31,326.05	$ 718.39	2.3%
4,000	$ 40,801.99	$ 41,758.07	$ 956.08	2.3%
5,000	$ 50,996.32	$ 52,190.09	$ 1,193.77	2.3%
6,000	$ 61,190.65	$ 62,622.10	$ 1,431.46	2.3%
7,000	$ 71,384.97	$ 73,054.12	$ 1,669.15	2.3%
8,000	$ 81,579.30	$ 83,486.14	$ 1,906.84	2.3%
9,000	$ 91,773.63	$ 93,918.16	$ 2,144.53	2.3%
10,000	$ 101,967.96	$ 104,350.17	$ 2,382.21	2.3%
20,000	$ 203,911.24	$ 208,670.35	$ 4,759.10	2.3%
30,000	$ 305,854.53	$ 312,990.52	$ 7,135.99	2.3%

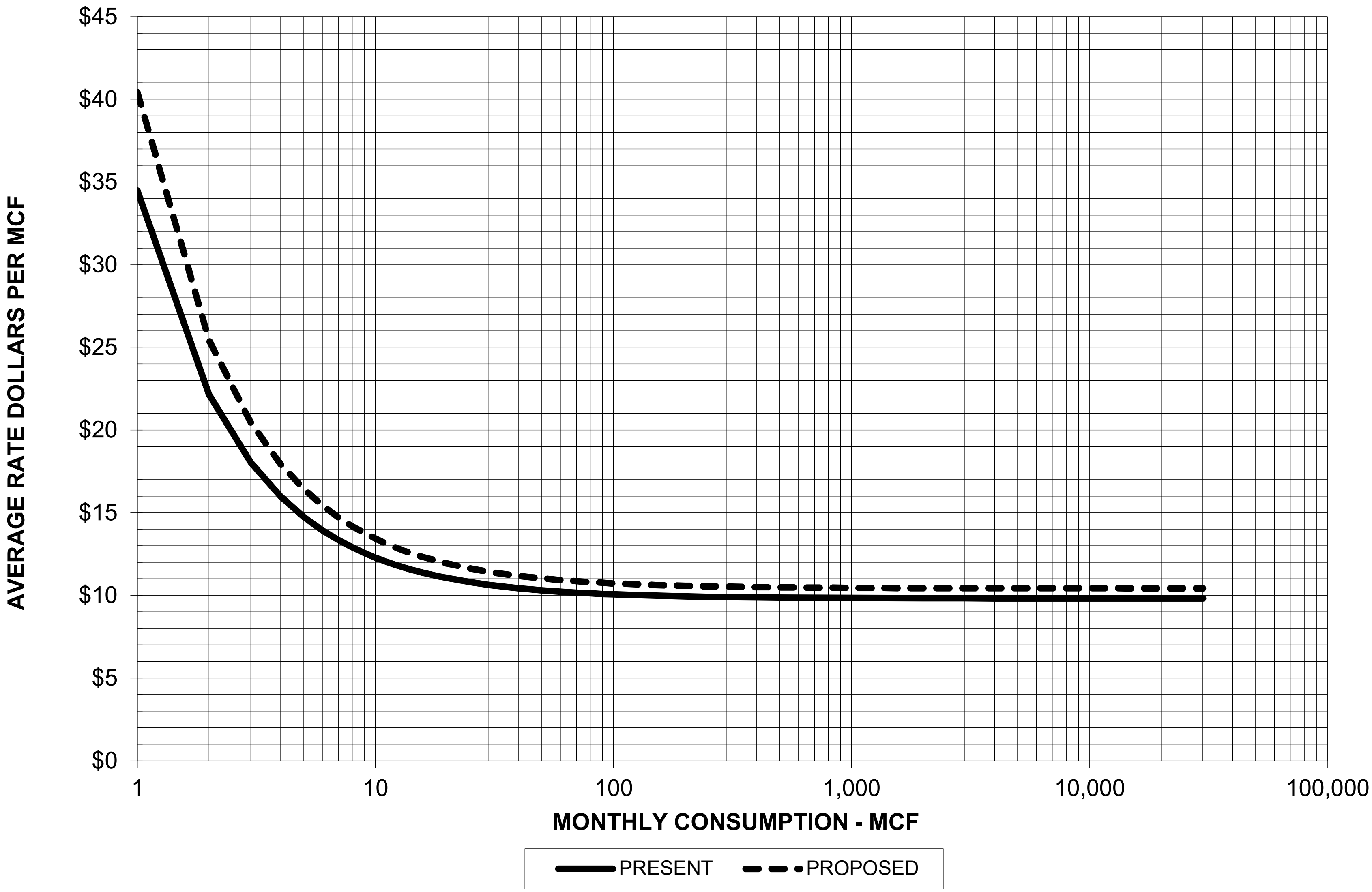
UGI Utilities, Inc.- Gas Division, Former South & Central Rate Districts
Comparison of Present and Proposed Rates
Rate Schedule N



UGI Utilities, Inc. - Gas Division, Former North Rate District
Non-Residential Service - Rate Schedule N
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 24.68	$ 30.00	$ 5.33	21.6%
1	$ 34.49	$ 40.43	$ 5.94	17.2%
2	$ 44.30	$ 50.86	$ 6.56	14.8%
3	$ 54.12	$ 61.30	$ 7.18	13.3%
4	$ 63.93	$ 71.73	$ 7.80	12.2%
5	$ 73.75	$ 82.16	$ 8.41	11.4%
6	$ 83.56	$ 92.59	$ 9.03	10.8%
7	$ 93.38	$ 103.02	$ 9.65	10.3%
8	$ 103.19	$ 113.46	$ 10.27	9.9%
9	$ 113.00	$ 123.89	$ 10.88	9.6%
10	$ 122.82	$ 134.32	$ 11.50	9.4%
11	$ 132.63	$ 144.75	$ 12.12	9.1%
12	$ 142.45	$ 155.18	$ 12.74	8.9%
13	$ 152.26	$ 165.62	$ 13.35	8.8%
14	$ 162.08	$ 176.05	$ 13.97	8.6%
15	$ 171.89	$ 186.48	$ 14.59	8.5%
16	$ 181.71	$ 196.91	$ 15.21	8.4%
17	$ 191.52	$ 207.34	$ 15.82	8.3%
18	$ 201.33	$ 217.78	$ 16.44	8.2%
19	$ 211.15	$ 228.21	$ 17.06	8.1%
20	$ 220.96	$ 238.64	$ 17.68	8.0%
25	$ 270.04	$ 290.80	$ 20.76	7.7%
30	$ 319.11	$ 342.96	$ 23.85	7.5%
35	$ 368.18	$ 395.12	$ 26.94	7.3%
40	$ 417.25	$ 447.28	$ 30.03	7.2%
45	$ 466.32	$ 499.44	$ 33.12	7.1%
50	$ 515.40	$ 551.60	$ 36.20	7.0%
60	$ 613.54	$ 655.92	$ 42.38	6.9%
70	$ 711.69	$ 760.24	$ 48.56	6.8%
80	$ 809.83	$ 864.56	$ 54.73	6.8%
90	$ 907.97	$ 968.88	$ 60.91	6.7%
100	$ 1,006.12	$ 1,073.20	$ 67.08	6.7%
125	$ 1,251.48	$ 1,334.00	$ 82.52	6.6%
150	$ 1,496.84	$ 1,594.80	$ 97.96	6.5%
200	$ 1,987.56	$ 2,116.40	$ 128.84	6.5%
250	$ 2,478.28	$ 2,638.00	$ 159.72	6.4%
300	$ 2,969.01	$ 3,159.61	$ 190.60	6.4%
400	$ 3,950.45	$ 4,202.81	$ 252.36	6.4%
500	$ 4,931.89	$ 5,246.01	$ 314.11	6.4%
1,000	$ 9,839.11	$ 10,462.02	$ 622.90	6.3%
2,000	$ 19,653.55	$ 20,894.03	$ 1,240.48	6.3%
3,000	$ 29,467.99	$ 31,326.05	$ 1,858.06	6.3%
4,000	$ 39,282.43	$ 41,758.07	$ 2,475.64	6.3%
5,000	$ 49,096.87	$ 52,190.09	$ 3,093.22	6.3%
6,000	$ 58,911.31	$ 62,622.10	$ 3,710.80	6.3%
7,000	$ 68,725.74	$ 73,054.12	$ 4,328.38	6.3%
8,000	$ 78,540.18	$ 83,486.14	$ 4,945.96	6.3%
9,000	$ 88,354.62	$ 93,918.16	$ 5,563.54	6.3%
10,000	$ 98,169.06	$ 104,350.17	$ 6,181.11	6.3%
20,000	$ 196,313.44	$ 208,670.35	$ 12,356.90	6.3%
30,000	$ 294,457.83	$ 312,990.52	$ 18,532.69	6.3%

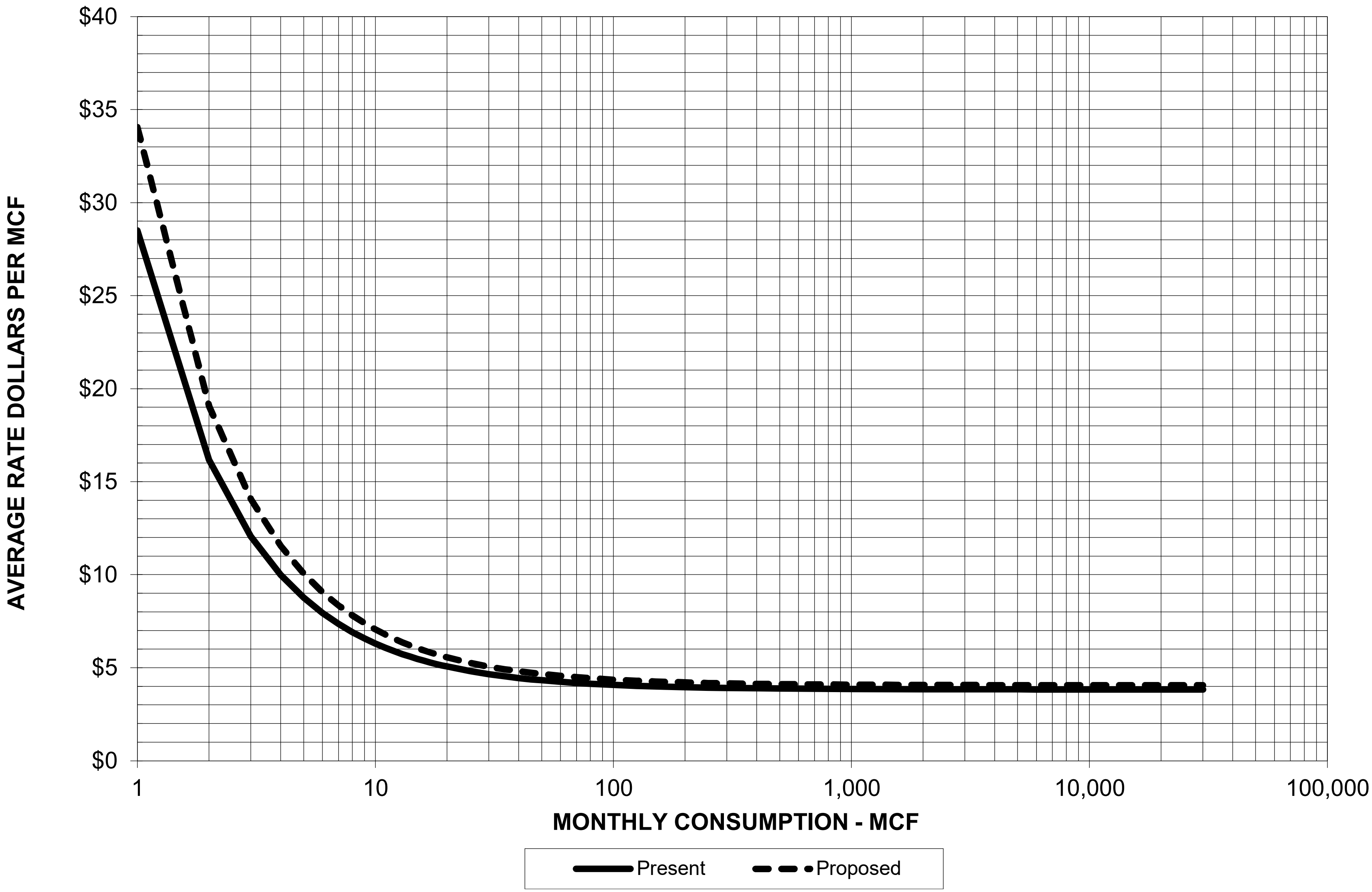
UGI Utilities, Inc.- Gas Division, Former North Rate District
Comparison of Present and Proposed Rates
Rate Schedule N



UGI Utilities, Inc. - Gas Division, Former South & Central Rate Districts
Non-Residential Transportation Service - Rate Schedule NT
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 24.68	$ 30.00	$ 5.33	21.6%
1	$ 28.50	$ 34.06	$ 5.56	19.5%
2	$ 32.33	$ 38.12	$ 5.79	17.9%
3	$ 36.16	$ 42.19	$ 6.02	16.6%
4	$ 39.99	$ 46.25	$ 6.25	15.6%
5	$ 43.82	$ 50.31	$ 6.48	14.8%
6	$ 47.65	$ 54.37	$ 6.72	14.1%
7	$ 51.48	$ 58.43	$ 6.95	13.5%
8	$ 55.31	$ 62.49	$ 7.18	13.0%
9	$ 59.14	$ 66.56	$ 7.41	12.5%
10	$ 62.97	$ 70.62	$ 7.64	12.1%
11	$ 66.80	$ 74.68	$ 7.88	11.8%
12	$ 70.63	$ 78.74	$ 8.11	11.5%
13	$ 74.46	$ 82.80	$ 8.34	11.2%
14	$ 78.29	$ 86.86	$ 8.57	10.9%
15	$ 82.12	$ 90.93	$ 8.80	10.7%
16	$ 85.95	$ 94.99	$ 9.03	10.5%
17	$ 89.78	$ 99.05	$ 9.27	10.3%
18	$ 93.61	$ 103.11	$ 9.50	10.1%
19	$ 97.44	$ 107.17	$ 9.73	10.0%
20	$ 101.27	$ 111.23	$ 9.96	9.8%
25	$ 120.42	$ 131.54	$ 11.12	9.2%
30	$ 139.57	$ 151.85	$ 12.28	8.8%
35	$ 158.72	$ 172.16	$ 13.44	8.5%
40	$ 177.87	$ 192.47	$ 14.60	8.2%
45	$ 197.02	$ 212.78	$ 15.76	8.0%
50	$ 216.17	$ 233.09	$ 16.92	7.8%
60	$ 254.47	$ 273.70	$ 19.23	7.6%
70	$ 292.77	$ 314.32	$ 21.55	7.4%
80	$ 331.07	$ 354.94	$ 23.87	7.2%
90	$ 369.36	$ 395.55	$ 26.19	7.1%
100	$ 407.66	$ 436.17	$ 28.51	7.0%
125	$ 503.41	$ 537.71	$ 34.30	6.8%
150	$ 599.16	$ 639.26	$ 40.10	6.7%
200	$ 790.65	$ 842.34	$ 51.69	6.5%
250	$ 982.14	$ 1,045.43	$ 63.28	6.4%
300	$ 1,173.64	$ 1,248.51	$ 74.87	6.4%
400	$ 1,556.63	$ 1,654.68	$ 98.06	6.3%
500	$ 1,939.61	$ 2,060.85	$ 121.24	6.3%
1,000	$ 3,854.55	$ 4,091.70	$ 237.15	6.2%
2,000	$ 7,684.43	$ 8,153.40	$ 468.97	6.1%
3,000	$ 11,514.30	$ 12,215.10	$ 700.80	6.1%
4,000	$ 15,344.18	$ 16,276.80	$ 932.63	6.1%
5,000	$ 19,174.05	$ 20,338.50	$ 1,164.45	6.1%
6,000	$ 23,003.93	$ 24,400.20	$ 1,396.28	6.1%
7,000	$ 26,833.80	$ 28,461.90	$ 1,628.10	6.1%
8,000	$ 30,663.68	$ 32,523.60	$ 1,859.93	6.1%
9,000	$ 34,493.55	$ 36,585.30	$ 2,091.75	6.1%
10,000	$ 38,323.43	$ 40,647.00	$ 2,323.58	6.1%
20,000	$ 76,622.18	$ 81,264.00	$ 4,641.83	6.1%
30,000	$ 114,920.93	$ 121,881.00	$ 6,960.07	6.1%

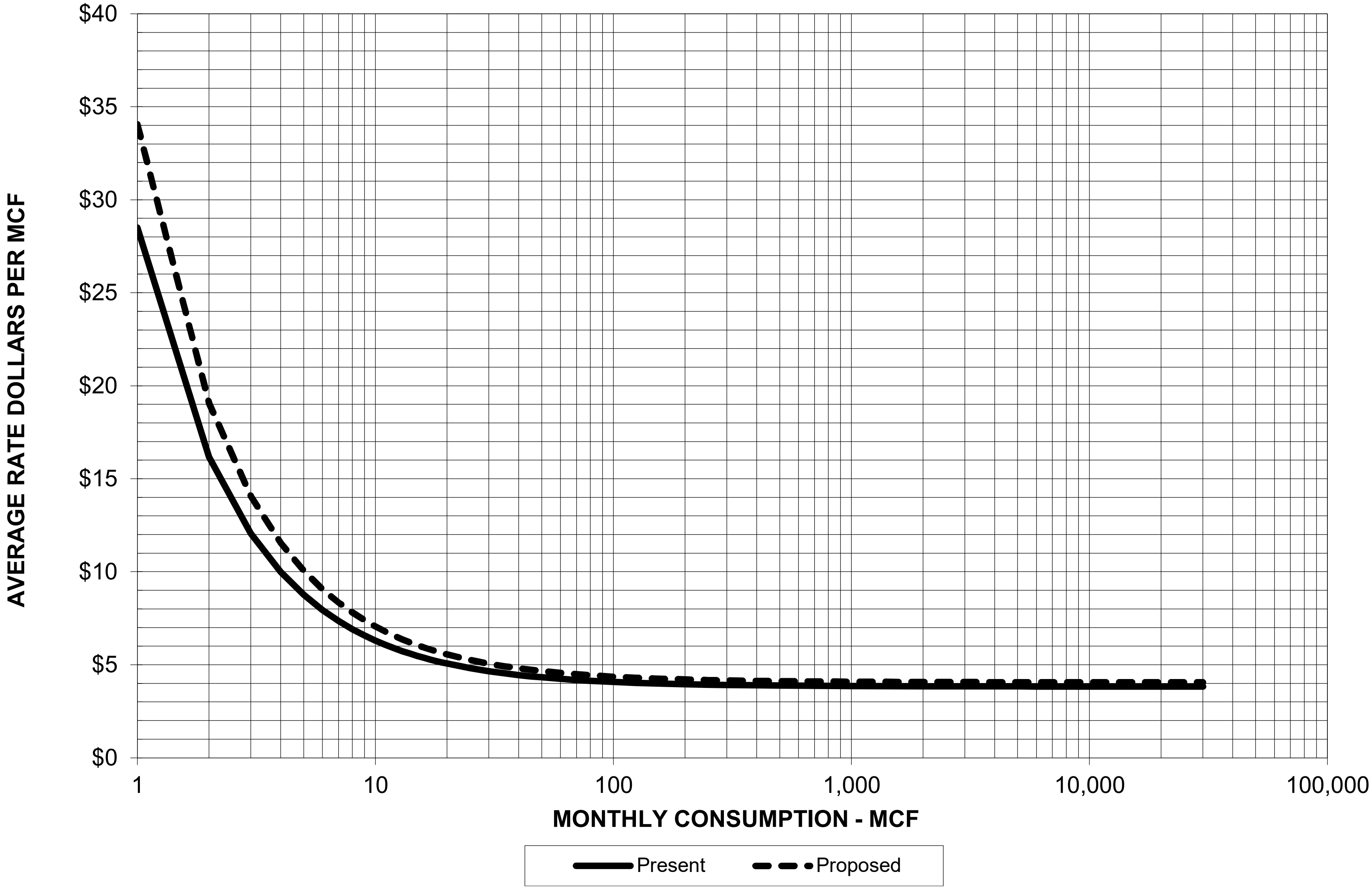
UGI Utilities, Inc. - Gas Division, Former South & Central Rate Districts
Comparison of Present and Proposed Rates
Rate Schedule NT



UGI Utilities, Inc. - Gas Division, Former North Rate District
Non-Residential Transportation Service - Rate Schedule NT
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 24.68	$ 30.00	$ 5.33	21.6%
1	$ 28.50	$ 34.06	$ 5.56	19.5%
2	$ 32.33	$ 38.12	$ 5.79	17.9%
3	$ 36.16	$ 42.19	$ 6.02	16.6%
4	$ 39.99	$ 46.25	$ 6.25	15.6%
5	$ 43.82	$ 50.31	$ 6.48	14.8%
6	$ 47.65	$ 54.37	$ 6.72	14.1%
7	$ 51.48	$ 58.43	$ 6.95	13.5%
8	$ 55.31	$ 62.49	$ 7.18	13.0%
9	$ 59.14	$ 66.56	$ 7.41	12.5%
10	$ 62.97	$ 70.62	$ 7.64	12.1%
11	$ 66.80	$ 74.68	$ 7.88	11.8%
12	$ 70.63	$ 78.74	$ 8.11	11.5%
13	$ 74.46	$ 82.80	$ 8.34	11.2%
14	$ 78.29	$ 86.86	$ 8.57	10.9%
15	$ 82.12	$ 90.93	$ 8.80	10.7%
16	$ 85.95	$ 94.99	$ 9.03	10.5%
17	$ 89.78	$ 99.05	$ 9.27	10.3%
18	$ 93.61	$ 103.11	$ 9.50	10.1%
19	$ 97.44	$ 107.17	$ 9.73	10.0%
20	$ 101.27	$ 111.23	$ 9.96	9.8%
25	$ 120.42	$ 131.54	$ 11.12	9.2%
30	$ 139.57	$ 151.85	$ 12.28	8.8%
35	$ 158.72	$ 172.16	$ 13.44	8.5%
40	$ 177.87	$ 192.47	$ 14.60	8.2%
45	$ 197.02	$ 212.78	$ 15.76	8.0%
50	$ 216.17	$ 233.09	$ 16.92	7.8%
60	$ 254.47	$ 273.70	$ 19.23	7.6%
70	$ 292.77	$ 314.32	$ 21.55	7.4%
80	$ 331.07	$ 354.94	$ 23.87	7.2%
90	$ 369.36	$ 395.55	$ 26.19	7.1%
100	$ 407.66	$ 436.17	$ 28.51	7.0%
125	$ 503.41	$ 537.71	$ 34.30	6.8%
150	$ 599.16	$ 639.26	$ 40.10	6.7%
200	$ 790.65	$ 842.34	$ 51.69	6.5%
250	$ 982.14	$ 1,045.43	$ 63.28	6.4%
300	$ 1,173.64	$ 1,248.51	$ 74.87	6.4%
400	$ 1,556.63	$ 1,654.68	$ 98.06	6.3%
500	$ 1,939.61	$ 2,060.85	$ 121.24	6.3%
1,000	$ 3,854.55	$ 4,091.70	$ 237.15	6.2%
2,000	$ 7,684.43	$ 8,153.40	$ 468.97	6.1%
3,000	$ 11,514.30	$ 12,215.10	$ 700.80	6.1%
4,000	$ 15,344.18	$ 16,276.80	$ 932.63	6.1%
5,000	$ 19,174.05	$ 20,338.50	$ 1,164.45	6.1%
6,000	$ 23,003.93	$ 24,400.20	$ 1,396.28	6.1%
7,000	$ 26,833.80	$ 28,461.90	$ 1,628.10	6.1%
8,000	$ 30,663.68	$ 32,523.60	$ 1,859.93	6.1%
9,000	$ 34,493.55	$ 36,585.30	$ 2,091.75	6.1%
10,000	$ 38,323.43	$ 40,647.00	$ 2,323.58	6.1%
20,000	$ 76,622.18	$ 81,264.00	$ 4,641.83	6.1%
30,000	$ 114,920.93	$ 121,881.00	$ 6,960.07	6.1%

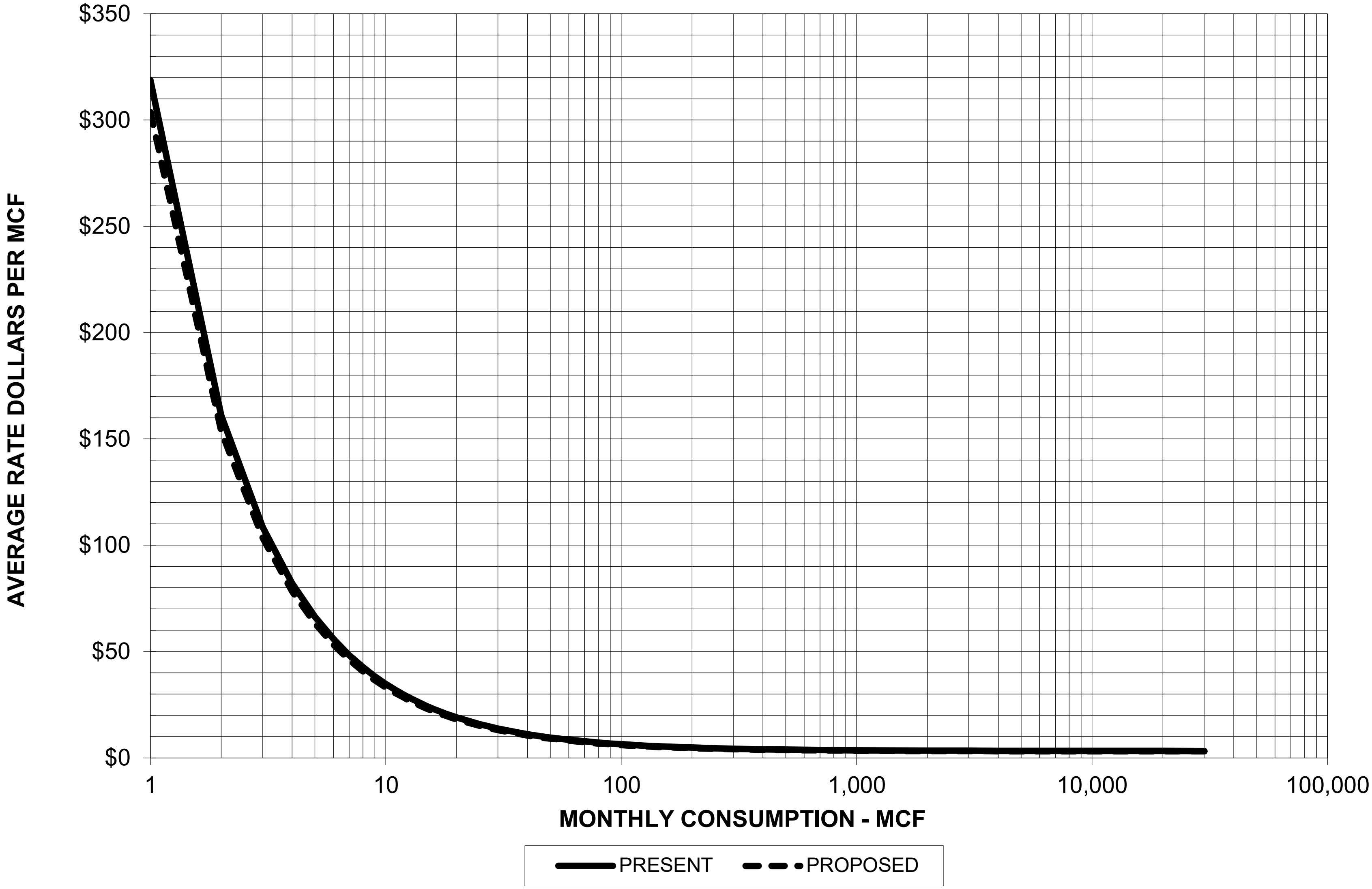
UGI Utilities, Inc. - Gas Division, Former North Rate District
Comparison of Present and Proposed Rates
Rate Schedule NT



UGI Utilities, Inc. - Gas Division -Former South and Central Rate Districts
Delivery Service - Rate Schedule DS
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 315.75	$ 300.72	$ (15.04)	-4.8%
1	$ 318.94	$ 303.78	$ (15.16)	-4.8%
2	$ 322.13	$ 306.84	$ (15.29)	-4.7%
3	$ 325.31	$ 309.90	$ (15.42)	-4.7%
4	$ 328.50	$ 312.96	$ (15.54)	-4.7%
5	$ 331.69	$ 316.02	$ (15.67)	-4.7%
6	$ 334.87	$ 319.07	$ (15.80)	-4.7%
7	$ 338.06	$ 322.13	$ (15.93)	-4.7%
8	$ 341.25	$ 325.19	$ (16.05)	-4.7%
9	$ 344.43	$ 328.25	$ (16.18)	-4.7%
10	$ 347.62	$ 331.31	$ (16.31)	-4.7%
11	$ 350.81	$ 334.37	$ (16.43)	-4.7%
12	$ 353.99	$ 337.43	$ (16.56)	-4.7%
13	$ 357.18	$ 340.49	$ (16.69)	-4.7%
14	$ 360.37	$ 343.55	$ (16.81)	-4.7%
15	$ 363.55	$ 346.61	$ (16.94)	-4.7%
16	$ 366.74	$ 349.67	$ (17.07)	-4.7%
17	$ 369.93	$ 352.73	$ (17.20)	-4.6%
18	$ 373.11	$ 355.79	$ (17.32)	-4.6%
19	$ 376.30	$ 358.85	$ (17.45)	-4.6%
20	$ 379.48	$ 361.91	$ (17.58)	-4.6%
25	$ 395.42	$ 377.21	$ (18.21)	-4.6%
30	$ 411.35	$ 392.50	$ (18.85)	-4.6%
35	$ 427.28	$ 407.80	$ (19.48)	-4.6%
40	$ 443.22	$ 423.10	$ (20.12)	-4.5%
45	$ 459.15	$ 438.40	$ (20.75)	-4.5%
50	$ 475.08	$ 453.69	$ (21.39)	-4.5%
60	$ 506.95	$ 484.29	$ (22.66)	-4.5%
70	$ 538.81	$ 514.88	$ (23.93)	-4.4%
80	$ 570.68	$ 545.48	$ (25.20)	-4.4%
90	$ 602.54	$ 576.07	$ (26.47)	-4.4%
100	$ 634.41	$ 606.67	$ (27.74)	-4.4%
125	$ 714.07	$ 683.16	$ (30.92)	-4.3%
150	$ 793.73	$ 759.64	$ (34.09)	-4.3%
200	$ 953.06	$ 912.62	$ (40.44)	-4.2%
250	$ 1,112.39	$ 1,065.59	$ (46.80)	-4.2%
300	$ 1,271.72	$ 1,218.57	$ (53.15)	-4.2%
400	$ 1,590.37	$ 1,524.52	$ (65.85)	-4.1%
500	$ 1,909.02	$ 1,830.47	$ (78.56)	-4.1%
1,000	$ 3,502.29	$ 3,360.22	$ (142.08)	-4.1%
2,000	$ 6,688.83	$ 6,419.72	$ (269.12)	-4.0%
3,000	$ 9,875.37	$ 9,479.22	$ (396.16)	-4.0%
4,000	$ 13,061.91	$ 12,538.72	$ (523.20)	-4.0%
5,000	$ 16,248.45	$ 15,598.22	$ (650.24)	-4.0%
6,000	$ 19,434.99	$ 18,657.72	$ (777.28)	-4.0%
7,000	$ 22,621.53	$ 21,717.22	$ (904.32)	-4.0%
8,000	$ 25,808.07	$ 24,776.72	$ (1,031.36)	-4.0%
9,000	$ 28,994.61	$ 27,836.22	$ (1,158.40)	-4.0%
10,000	$ 32,181.15	$ 30,895.72	$ (1,285.44)	-4.0%
20,000	$ 64,046.55	$ 61,490.72	$ (2,555.84)	-4.0%
30,000	$ 95,911.95	$ 92,085.72	$ (3,826.24)	-4.0%

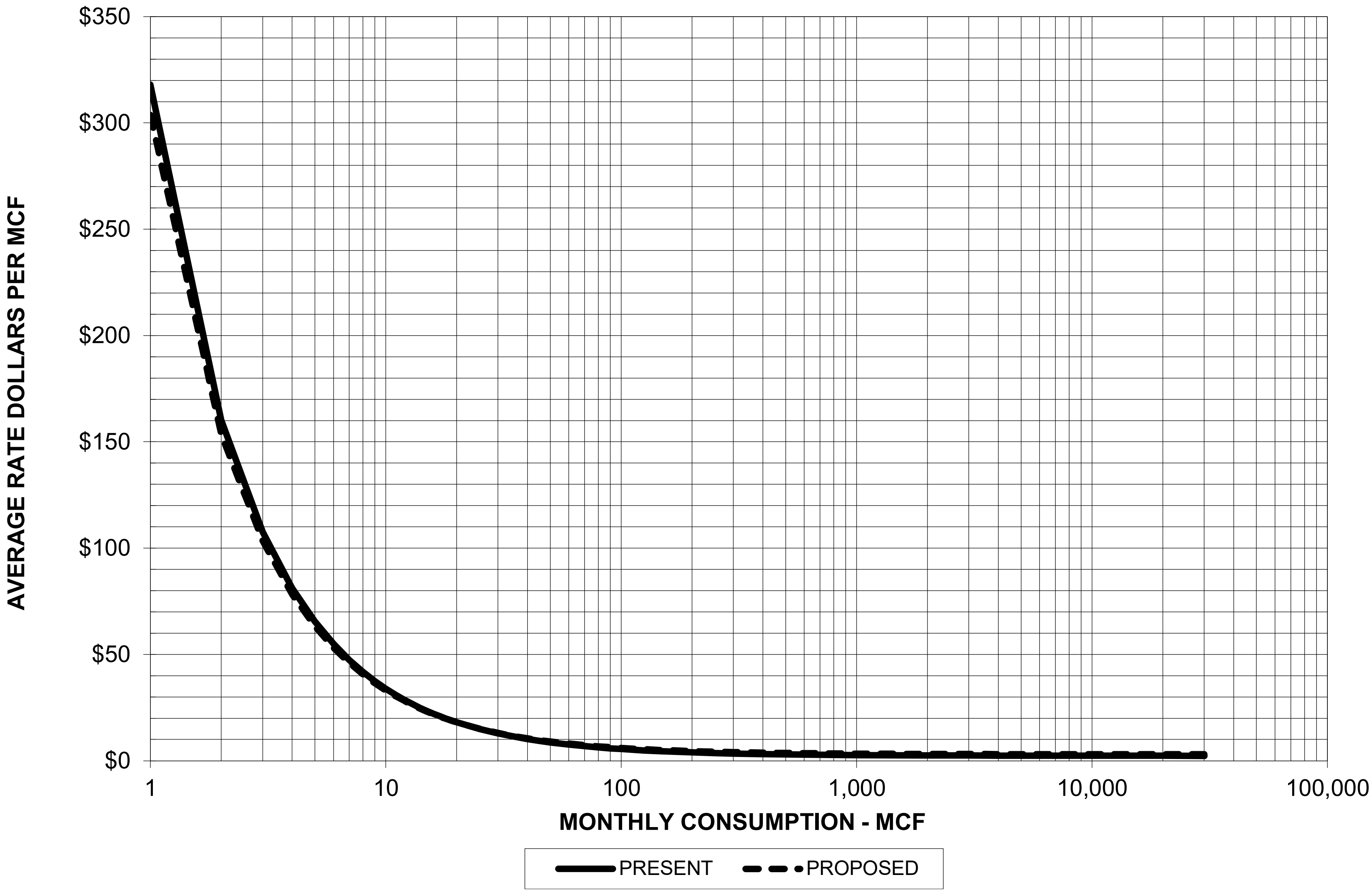
UGI Utilities, Inc. - Gas Division, Former South & Central Rate Districts
Comparison of Present and Proposed Rates
Rate Schedule DS



UGI Utilities, Inc. - Gas Division -Former North Rate District
Delivery Service - Rate Schedule DS
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 315.75	$ 300.72	$ (15.04)	-4.8%
1	$ 318.08	$ 303.78	$ (14.30)	-4.5%
2	$ 320.40	$ 306.84	$ (13.56)	-4.2%
3	$ 322.73	$ 309.90	$ (12.83)	-4.0%
4	$ 325.05	$ 312.96	$ (12.09)	-3.7%
5	$ 327.37	$ 316.02	$ (11.36)	-3.5%
6	$ 329.70	$ 319.07	$ (10.62)	-3.2%
7	$ 332.02	$ 322.13	$ (9.89)	-3.0%
8	$ 334.35	$ 325.19	$ (9.15)	-2.7%
9	$ 336.67	$ 328.25	$ (8.42)	-2.5%
10	$ 338.99	$ 331.31	$ (7.68)	-2.3%
11	$ 341.32	$ 334.37	$ (6.95)	-2.0%
12	$ 343.64	$ 337.43	$ (6.21)	-1.8%
13	$ 345.97	$ 340.49	$ (5.47)	-1.6%
14	$ 348.29	$ 343.55	$ (4.74)	-1.4%
15	$ 350.61	$ 346.61	$ (4.00)	-1.1%
16	$ 352.94	$ 349.67	$ (3.27)	-0.9%
17	$ 355.26	$ 352.73	$ (2.53)	-0.7%
18	$ 357.59	$ 355.79	$ (1.80)	-0.5%
19	$ 359.91	$ 358.85	$ (1.06)	-0.3%
20	$ 362.23	$ 361.91	$ (0.33)	-0.1%
25	$ 373.85	$ 377.21	$ 3.35	0.9%
30	$ 385.47	$ 392.50	$ 7.03	1.8%
35	$ 397.09	$ 407.80	$ 10.71	2.7%
40	$ 408.71	$ 423.10	$ 14.39	3.5%
45	$ 420.33	$ 438.40	$ 18.06	4.3%
50	$ 431.95	$ 453.69	$ 21.74	5.0%
60	$ 455.19	$ 484.29	$ 29.10	6.4%
70	$ 478.43	$ 514.88	$ 36.45	7.6%
80	$ 501.67	$ 545.48	$ 43.81	8.7%
90	$ 524.91	$ 576.07	$ 51.16	9.7%
100	$ 548.15	$ 606.67	$ 58.52	10.7%
125	$ 606.25	$ 683.16	$ 76.91	12.7%
150	$ 664.35	$ 759.64	$ 95.29	14.3%
200	$ 780.55	$ 912.62	$ 132.07	16.9%
250	$ 896.75	$ 1,065.59	$ 168.85	18.8%
300	$ 1,012.94	$ 1,218.57	$ 205.62	20.3%
400	$ 1,245.34	$ 1,524.52	$ 279.18	22.4%
500	$ 1,477.74	$ 1,830.47	$ 352.73	23.9%
1,000	$ 2,639.72	$ 3,360.22	$ 720.50	27.3%
2,000	$ 4,963.68	$ 6,419.72	$ 1,456.03	29.3%
3,000	$ 7,287.65	$ 9,479.22	$ 2,191.57	30.1%
4,000	$ 9,611.61	$ 12,538.72	$ 2,927.10	30.5%
5,000	$ 11,935.58	$ 15,598.22	$ 3,662.64	30.7%
6,000	$ 14,259.54	$ 18,657.72	$ 4,398.17	30.8%
7,000	$ 16,583.51	$ 21,717.22	$ 5,133.71	31.0%
8,000	$ 18,907.47	$ 24,776.72	$ 5,869.24	31.0%
9,000	$ 21,231.44	$ 27,836.22	$ 6,604.78	31.1%
10,000	$ 23,555.40	$ 30,895.72	$ 7,340.31	31.2%
20,000	$ 46,795.05	$ 61,490.72	$ 14,695.66	31.4%
30,000	$ 70,034.70	$ 92,085.72	$ 22,051.01	31.5%

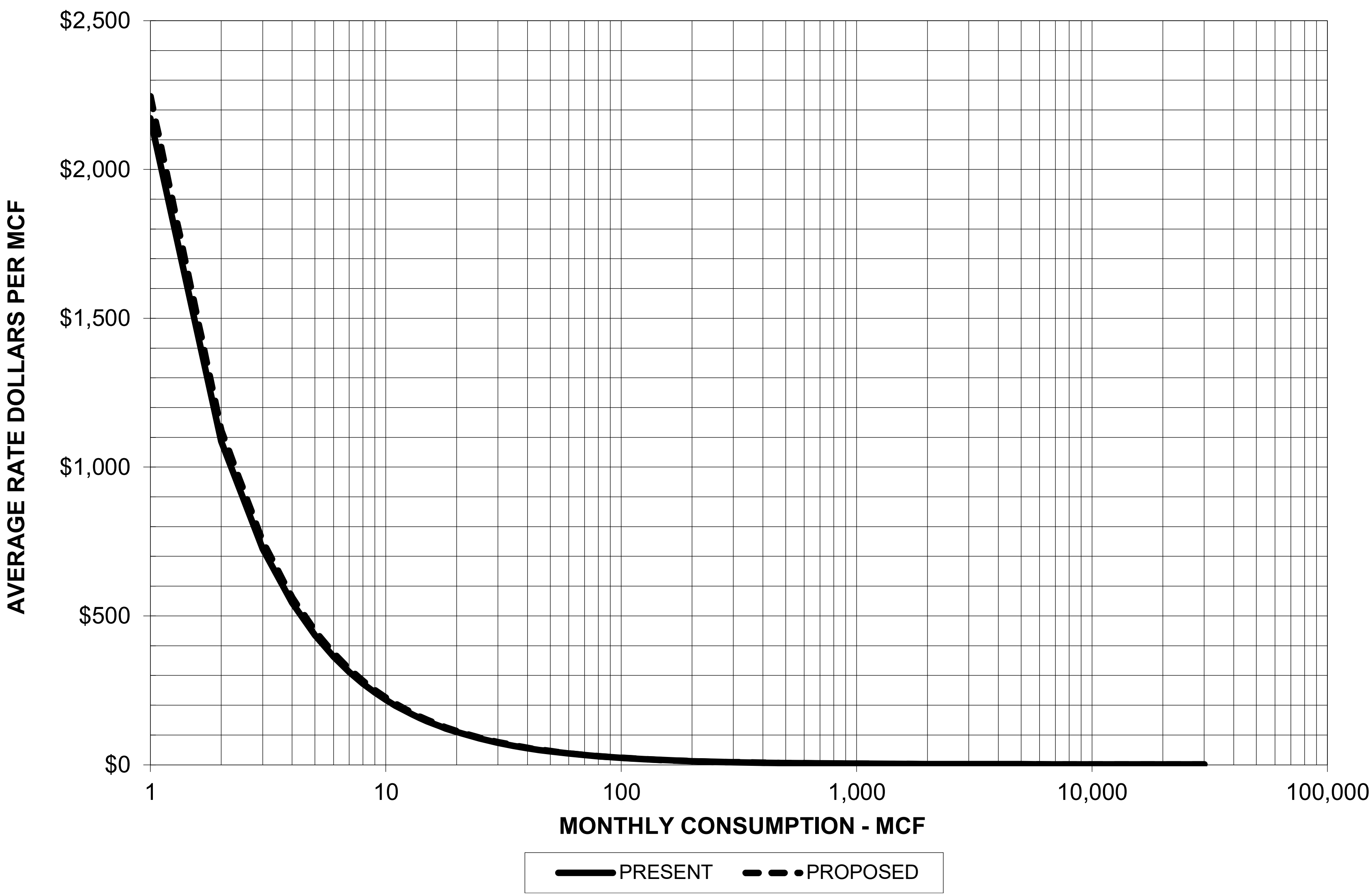
UGI Utilities, Inc. - Gas Division, Former North Rate District
Comparison of Present and Proposed Rates
Rate Schedule DS



UGI Utilities, Inc. - Gas Division
Large Firm Delivery Service - Rate Schedule LFD
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 2,171.11	$ 2,245.24	$ 74.13	3.4%
1	$ 2,172.34	$ 2,246.52	$ 74.18	3.4%
2	$ 2,173.58	$ 2,247.79	$ 74.22	3.4%
3	$ 2,174.81	$ 2,249.07	$ 74.26	3.4%
4	$ 2,176.04	$ 2,250.35	$ 74.30	3.4%
5	$ 2,177.28	$ 2,251.62	$ 74.34	3.4%
6	$ 2,178.51	$ 2,252.90	$ 74.39	3.4%
7	$ 2,179.75	$ 2,254.18	$ 74.43	3.4%
8	$ 2,180.98	$ 2,255.45	$ 74.47	3.4%
9	$ 2,182.22	$ 2,256.73	$ 74.51	3.4%
10	$ 2,183.45	$ 2,258.00	$ 74.55	3.4%
11	$ 2,184.68	$ 2,259.28	$ 74.60	3.4%
12	$ 2,185.92	$ 2,260.56	$ 74.64	3.4%
13	$ 2,187.15	$ 2,261.83	$ 74.68	3.4%
14	$ 2,188.39	$ 2,263.11	$ 74.72	3.4%
15	$ 2,189.62	$ 2,264.39	$ 74.77	3.4%
16	$ 2,190.86	$ 2,265.66	$ 74.81	3.4%
17	$ 2,192.09	$ 2,266.94	$ 74.85	3.4%
18	$ 2,193.32	$ 2,268.22	$ 74.89	3.4%
19	$ 2,194.56	$ 2,269.49	$ 74.93	3.4%
20	$ 2,195.79	$ 2,270.77	$ 74.98	3.4%
25	$ 2,201.96	$ 2,277.15	$ 75.19	3.4%
30	$ 2,208.14	$ 2,283.53	$ 75.40	3.4%
35	$ 2,214.31	$ 2,289.91	$ 75.61	3.4%
40	$ 2,220.48	$ 2,296.30	$ 75.82	3.4%
45	$ 2,226.65	$ 2,302.68	$ 76.03	3.4%
50	$ 2,232.82	$ 2,309.06	$ 76.24	3.4%
60	$ 2,245.16	$ 2,321.82	$ 76.66	3.4%
70	$ 2,257.51	$ 2,334.59	$ 77.08	3.4%
80	$ 2,269.85	$ 2,347.35	$ 77.50	3.4%
90	$ 2,282.19	$ 2,360.12	$ 77.92	3.4%
100	$ 2,294.54	$ 2,372.88	$ 78.35	3.4%
125	$ 2,325.39	$ 2,404.79	$ 79.40	3.4%
150	$ 2,356.25	$ 2,436.70	$ 80.45	3.4%
200	$ 2,417.96	$ 2,500.52	$ 82.56	3.4%
250	$ 2,479.68	$ 2,564.34	$ 84.66	3.4%
300	$ 2,541.39	$ 2,628.16	$ 86.77	3.4%
400	$ 2,664.82	$ 2,755.80	$ 90.98	3.4%
500	$ 2,788.25	$ 2,883.44	$ 95.19	3.4%
1,000	$ 3,405.39	$ 3,521.64	$ 116.25	3.4%
2,000	$ 4,639.67	$ 4,798.04	$ 158.37	3.4%
3,000	$ 5,873.95	$ 6,074.44	$ 200.49	3.4%
4,000	$ 7,108.23	$ 7,350.84	$ 242.61	3.4%
5,000	$ 8,342.51	$ 8,627.24	$ 284.73	3.4%
6,000	$ 9,576.79	$ 9,903.64	$ 326.85	3.4%
7,000	$ 10,811.07	$ 11,180.04	$ 368.97	3.4%
8,000	$ 12,045.35	$ 12,456.44	$ 411.09	3.4%
9,000	$ 13,279.63	$ 13,732.84	$ 453.21	3.4%
10,000	$ 14,513.91	$ 15,009.24	$ 495.33	3.4%
20,000	$ 26,856.71	$ 27,773.24	$ 916.53	3.4%
30,000	$ 39,199.51	$ 40,537.24	$ 1,337.73	3.4%

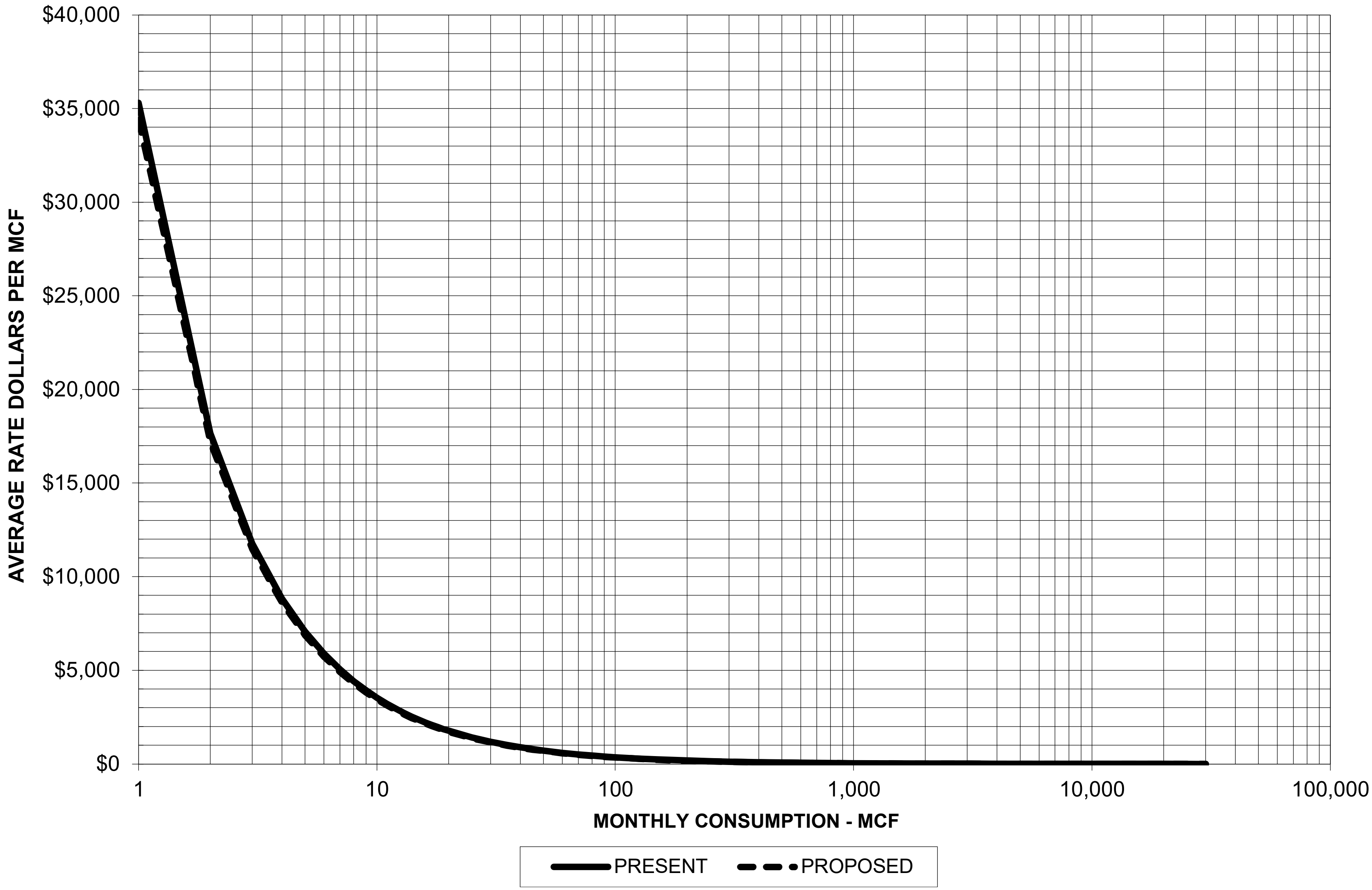
UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule LFD



UGI Utilities, Inc. - Gas Division
Extended Large Firm Delivery Service - Rate Schedule XD
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 35,319.21	$ 34,393.51	$ (925.70)	-2.6%
1	$ 35,319.27	$ 34,393.57	$ (925.70)	-2.6%
2	$ 35,319.33	$ 34,393.62	$ (925.71)	-2.6%
3	$ 35,319.38	$ 34,393.68	$ (925.71)	-2.6%
4	$ 35,319.44	$ 34,393.73	$ (925.71)	-2.6%
5	$ 35,319.49	$ 34,393.79	$ (925.71)	-2.6%
6	$ 35,319.55	$ 34,393.84	$ (925.71)	-2.6%
7	$ 35,319.61	$ 34,393.89	$ (925.71)	-2.6%
8	$ 35,319.66	$ 34,393.95	$ (925.71)	-2.6%
9	$ 35,319.72	$ 34,394.00	$ (925.72)	-2.6%
10	$ 35,319.78	$ 34,394.06	$ (925.72)	-2.6%
11	$ 35,319.83	$ 34,394.11	$ (925.72)	-2.6%
12	$ 35,319.89	$ 34,394.17	$ (925.72)	-2.6%
13	$ 35,319.94	$ 34,394.22	$ (925.72)	-2.6%
14	$ 35,320.00	$ 34,394.28	$ (925.72)	-2.6%
15	$ 35,320.06	$ 34,394.33	$ (925.72)	-2.6%
16	$ 35,320.11	$ 34,394.39	$ (925.73)	-2.6%
17	$ 35,320.17	$ 34,394.44	$ (925.73)	-2.6%
18	$ 35,320.23	$ 34,394.50	$ (925.73)	-2.6%
19	$ 35,320.28	$ 34,394.55	$ (925.73)	-2.6%
20	$ 35,320.34	$ 34,394.61	$ (925.73)	-2.6%
25	$ 35,320.62	$ 34,394.88	$ (925.74)	-2.6%
30	$ 35,320.90	$ 34,395.15	$ (925.75)	-2.6%
35	$ 35,321.18	$ 34,395.43	$ (925.75)	-2.6%
40	$ 35,321.46	$ 34,395.70	$ (925.76)	-2.6%
45	$ 35,321.74	$ 34,395.98	$ (925.77)	-2.6%
50	$ 35,322.03	$ 34,396.25	$ (925.78)	-2.6%
60	$ 35,322.59	$ 34,396.80	$ (925.79)	-2.6%
70	$ 35,323.15	$ 34,397.35	$ (925.81)	-2.6%
80	$ 35,323.71	$ 34,397.89	$ (925.82)	-2.6%
90	$ 35,324.28	$ 34,398.44	$ (925.83)	-2.6%
100	$ 35,324.84	$ 34,398.99	$ (925.85)	-2.6%
125	$ 35,326.24	$ 34,400.36	$ (925.89)	-2.6%
150	$ 35,327.65	$ 34,401.73	$ (925.92)	-2.6%
200	$ 35,330.46	$ 34,404.46	$ (926.00)	-2.6%
250	$ 35,333.27	$ 34,407.20	$ (926.07)	-2.6%
300	$ 35,336.08	$ 34,409.94	$ (926.14)	-2.6%
400	$ 35,341.71	$ 34,415.42	$ (926.29)	-2.6%
500	$ 35,347.33	$ 34,420.89	$ (926.44)	-2.6%
1,000	$ 35,375.45	$ 34,448.27	$ (927.18)	-2.6%
2,000	$ 35,431.69	$ 34,503.04	$ (928.65)	-2.6%
3,000	$ 35,487.93	$ 34,557.80	$ (930.12)	-2.6%
4,000	$ 35,544.16	$ 34,612.56	$ (931.60)	-2.6%
5,000	$ 35,600.40	$ 34,667.33	$ (933.07)	-2.6%
6,000	$ 35,656.64	$ 34,722.09	$ (934.55)	-2.6%
7,000	$ 35,712.87	$ 34,776.85	$ (936.02)	-2.6%
8,000	$ 35,769.11	$ 34,831.62	$ (937.49)	-2.6%
9,000	$ 35,825.35	$ 34,886.38	$ (938.97)	-2.6%
10,000	$ 35,881.59	$ 34,941.14	$ (940.44)	-2.6%
20,000	$ 36,443.96	$ 35,488.78	$ (955.18)	-2.6%
30,000	$ 37,006.33	$ 36,036.41	$ (969.92)	-2.6%

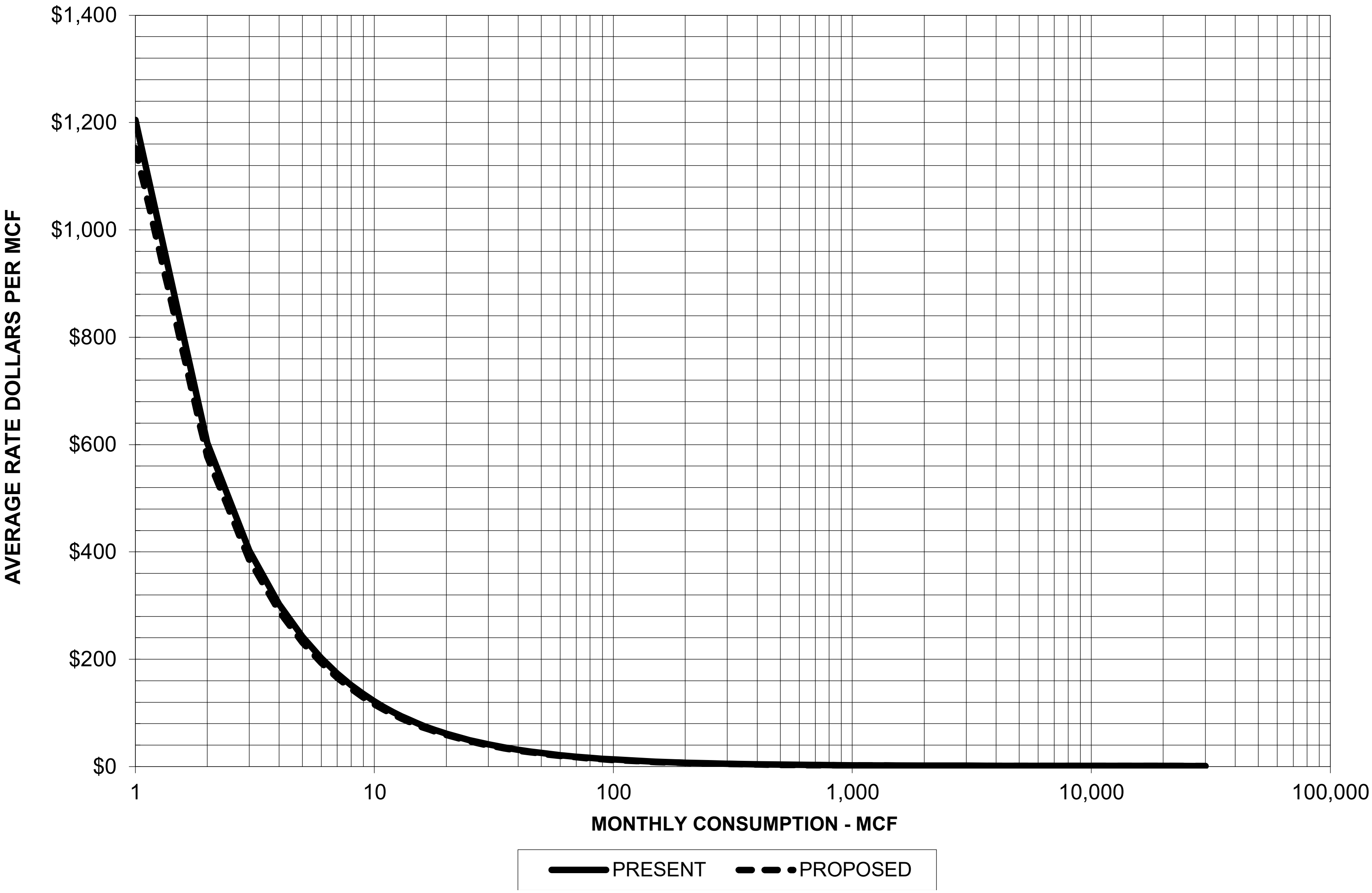
UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule XD



UGI Utilities, Inc. - Gas Division
Interruptible Service - Rate Schedule IS
Calculation of the Effect of Proposed Rates

MCF	Bills Under Present Rates	Bills Under Proposed Rates	Increase Amount	Increase Percent
-	$ 1,204.20	$ 1,151.59	$ (52.62)	-4.4%
1	$ 1,205.42	$ 1,152.75	$ (52.67)	-4.4%
2	$ 1,206.63	$ 1,153.91	$ (52.72)	-4.4%
3	$ 1,207.85	$ 1,155.07	$ (52.78)	-4.4%
4	$ 1,209.06	$ 1,156.23	$ (52.83)	-4.4%
5	$ 1,210.27	$ 1,157.39	$ (52.88)	-4.4%
6	$ 1,211.49	$ 1,158.55	$ (52.93)	-4.4%
7	$ 1,212.70	$ 1,159.72	$ (52.99)	-4.4%
8	$ 1,213.92	$ 1,160.88	$ (53.04)	-4.4%
9	$ 1,215.13	$ 1,162.04	$ (53.09)	-4.4%
10	$ 1,216.35	$ 1,163.20	$ (53.15)	-4.4%
11	$ 1,217.56	$ 1,164.36	$ (53.20)	-4.4%
12	$ 1,218.78	$ 1,165.52	$ (53.25)	-4.4%
13	$ 1,219.99	$ 1,166.68	$ (53.31)	-4.4%
14	$ 1,221.20	$ 1,167.85	$ (53.36)	-4.4%
15	$ 1,222.42	$ 1,169.01	$ (53.41)	-4.4%
16	$ 1,223.63	$ 1,170.17	$ (53.46)	-4.4%
17	$ 1,224.85	$ 1,171.33	$ (53.52)	-4.4%
18	$ 1,226.06	$ 1,172.49	$ (53.57)	-4.4%
19	$ 1,227.28	$ 1,173.65	$ (53.62)	-4.4%
20	$ 1,228.49	$ 1,174.81	$ (53.68)	-4.4%
25	$ 1,234.56	$ 1,180.62	$ (53.94)	-4.4%
30	$ 1,240.64	$ 1,186.43	$ (54.21)	-4.4%
35	$ 1,246.71	$ 1,192.24	$ (54.47)	-4.4%
40	$ 1,252.78	$ 1,198.04	$ (54.74)	-4.4%
45	$ 1,258.86	$ 1,203.85	$ (55.00)	-4.4%
50	$ 1,264.93	$ 1,209.66	$ (55.27)	-4.4%
60	$ 1,277.07	$ 1,221.27	$ (55.80)	-4.4%
70	$ 1,289.22	$ 1,232.89	$ (56.33)	-4.4%
80	$ 1,301.36	$ 1,244.50	$ (56.86)	-4.4%
90	$ 1,313.51	$ 1,256.12	$ (57.39)	-4.4%
100	$ 1,325.65	$ 1,267.73	$ (57.92)	-4.4%
125	$ 1,356.02	$ 1,296.77	$ (59.25)	-4.4%
150	$ 1,386.38	$ 1,325.80	$ (60.58)	-4.4%
200	$ 1,447.11	$ 1,383.88	$ (63.23)	-4.4%
250	$ 1,507.83	$ 1,441.95	$ (65.88)	-4.4%
300	$ 1,568.56	$ 1,500.02	$ (68.54)	-4.4%
400	$ 1,690.01	$ 1,616.17	$ (73.84)	-4.4%
500	$ 1,811.47	$ 1,732.32	$ (79.15)	-4.4%
1,000	$ 2,418.73	$ 2,313.05	$ (105.68)	-4.4%
2,000	$ 3,633.26	$ 3,474.51	$ (158.75)	-4.4%
3,000	$ 4,847.78	$ 4,635.97	$ (211.82)	-4.4%
4,000	$ 6,062.31	$ 5,797.43	$ (264.88)	-4.4%
5,000	$ 7,276.84	$ 6,958.89	$ (317.95)	-4.4%
6,000	$ 8,491.37	$ 8,120.35	$ (371.02)	-4.4%
7,000	$ 9,705.89	$ 9,281.81	$ (424.09)	-4.4%
8,000	$ 10,920.42	$ 10,443.27	$ (477.15)	-4.4%
9,000	$ 12,134.95	$ 11,604.73	$ (530.22)	-4.4%
10,000	$ 13,349.48	$ 12,766.19	$ (583.29)	-4.4%
20,000	$ 25,494.75	$ 24,380.79	$ (1,113.96)	-4.4%
30,000	$ 37,640.03	$ 35,995.40	$ (1,644.63)	-4.4%

UGI Utilities, Inc. - Gas Division
Comparison of Present and Proposed Rates
Rate Schedule IS



IV-B-8

Request:

Supply a map showing the Gas System Facilities and Gas Service Areas. The map should include transmission lines, distribution lines, other companies' lines interconnecting with the interconnecting points clearly designated, major compressor stations, gas storage areas and gas storage lines. The normal direction of gas flow within the transmission system should be indicated by arrows. Separate service areas within the system should be clearly designated.

Response:

Please see the response to I-C-2.

Prepared by or under the supervision of: Christopher R. Brown

IV-B-9

Request:

Supply a cost analysis supporting minimum charges for all rate schedules.

Response:

Please see UGI Gas Exhibit D, Schedule G.

Prepared by or under the supervision of: Constance E. Heppenstall

IV-B-10

Request:

Supply a cost analysis supporting demand charges for all tariffs which contain demand charges.

Response:

Please see UGI Gas Exhibit D, Schedule H.

Prepared by or under the supervision of: Constance E. Heppenstall

IV-B-11

Request:

Supply the net fuel clause adjustment by month for the test year.

Response:

The Company does not have a net fuel clause adjustment.

Prepared by or under the supervision of: Christopher R. Brown

IV-B-12

Request:

Supply a tabulation of base rate bills for each rate schedule comparing the existing rates to proposed rates. The tabulation should show the dollar difference and the per cent increase or decrease.

Response:

Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8, and the responses to IV-B-5 and IV-B-7.

Prepared by or under the supervision of: Sherry A. Epler

IV-B-13

Request:

Submit the projected demands for all customer classes for both purchased and produced gas for the three years following the test year filing.

Response:

Please reference Attachment 4-1 of UGI Gas Docket No. R-2021-3025652 in the most recent Annual 1307(f) Purchased Gas Cost ("PGC") filings which can be found at URL https://www.puc.pa.gov/pcdocs/1702100.pdf.

Prepared by or under the supervision of: Christopher R. Brown

IV-B-14

Request:

Supply an exhibit showing the gas deliveries to each customer class for the most recent 24 month period. The exhibit should identify the source of the gas, such as "purchased" (pipeline), "production" (includes purchases from local producers), "storage withdrawal," "propane/air," and "unaccounted for."

Response:

Please see Attachment IV-B-14.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Deliveries by Rate Class (MCF)

	Rate R Residential Non Heating	Rate GL Residential Gas Lights	Rate R Residential Heating	Rate RT Residential Transportation	Rate N Commercial Non Heating	Rate GL Commercial Gas Lights	Rate N Commercial Heating	Rate N Industrial Non Heating	Rate N Industrial Heating	Rate NT Non-Residential Transportation	Rate DS Delivery Service	Rate XD Extended Large Volume Delivery Service	Rate LFD Large Firm Delivery Service	Rate IS Interruptible Service Transportation	Co Use	Unaccounted for Gas
October 2019	26,701	122	1,726,999	255,817	54,679	508	604,415	7,648	18,615	637,340	591,000	14,841,308	1,713,349	1,226,183	11,287	209,608
November 2019	36,147	133	5,273,189	747,355	65,583	1,118	2,022,928	10,566	76,667	1,688,474	1,119,143	14,235,021	2,102,516	1,336,259	18,302	1,453,577
December 2019	58,422	117	7,688,605	1,246,404	94,542	753	2,178,347	16,388	97,959	1,569,409	1,537,219	15,799,590	2,329,663	1,397,937	25,319	562,956
January 2020	55,850	113	7,049,714	1,063,929	109,606	891	2,594,543	24,390	145,167	2,137,780	1,511,257	17,786,998	2,498,168	1,402,549	44,782	(207,196)
February 2020	41,320	110	5,863,516	858,353	114,947	912	2,432,882	31,590	119,565	1,826,064	1,563,260	17,474,113	2,263,967	1,297,829	44,006	(1,137,014)
March 2020	34,013	121	4,272,580	628,843	81,408	2,736	2,254,149	12,434	73,468	1,311,864	559,797	15,272,166	2,058,455	1,036,856	50,229	(1,107,415)
April 2020	38,033	120	3,939,351	634,022	44,386	1,449	597,724	8,684	50,899	1,033,303	762,340	13,660,578	1,745,735	963,614	32,882	939,797
May 2020	26,010	147	1,893,647	295,875	40,120	3,337	571,706	4,780	27,478	519,688	465,118	11,328,005	1,447,773	1,119,010	27,214	(630,322)
June 2020	24,354	308	882,879	174,934	41,185	(3,212)	268,773	(1,626)	6,895	377,096	103,243	15,343,604	1,422,894	688,518	21,721	942,153
July 2020	21,468	173	770,236	121,775	36,955	1,122	234,472	(1,116)	9,531	341,518	233,175	18,800,016	1,342,388	873,498	14,939	214,092
August 2020	13,813	154	497,340	85,659	37,099	952	215,831	356	7,321	314,248	232,407	19,037,472	1,401,852	1,165,178	13,441	(219,936)
September 2020	23,831	43	843,395	156,136	17,519	212	280,105	3,101	12,547	418,842	280,504	17,169,326	1,444,360	981,420	16,729	(266,124)
October 2020	30,120	130	1,893,203	281,495	48,097	668	539,461	4,329	24,100	642,623	667,417	15,933,792	1,684,588	1,252,959	47,751	469,280
November 2020	38,873	148	4,451,482	675,580	67,443	938	1,383,168	8,263	54,812	1,221,772	832,311	13,826,279	1,874,066	1,276,615	37,449	717,201
December 2020	46,647	122	6,564,125	1,005,334	70,928	903	2,311,740	18,261	111,414	1,775,026	1,355,267	17,276,341	2,340,569	1,418,559	42,644	(475,472)
January 2021	60,134	128	8,110,541	1,243,990	85,692	916	2,939,003	22,751	138,083	2,253,205	1,498,429	16,497,667	2,574,085	1,387,376	43,656	508,921
February 2021	48,001	119	7,648,486	1,178,717	78,895	1,502	2,728,085	16,320	119,871	2,125,253	1,365,526	15,360,567	2,410,610	1,232,337	45,938	(200,579)
March 2021	45,912	131	5,156,749	767,294	74,873	971	1,948,284	18,252	111,698	1,449,427	1,063,959	14,955,007	2,252,672	1,259,630	54,885	(82,547)
April 2021	28,238	117	2,943,254	428,099	52,667	649	1,046,132	8,083	44,171	915,781	645,876	12,958,666	1,863,697	1,156,622	33,591	(191,082)
May 2021	21,368	119	1,584,888	227,423	39,262	820	550,722	3,774	77,515	581,099	421,522	13,597,570	1,636,038	1,072,136	26,499	(70,735)
June 2021	13,913	94	759,236	115,799	28,741	269	302,895	1,802	(26,605)	353,628	278,965	15,864,268	1,469,480	990,706	18,415	(198,206)
July 2021	19,375	128	737,900	111,218	34,682	929	292,323	2,896	11,009	381,553	273,711	18,027,536	1,407,873	999,831	13,862	143,941
August 2021	19,041	116	712,643	109,260	40,457	987	288,097	17,250	10,930	405,846	265,611	18,141,314	1,483,329	958,785	15,695	98,416
September 2021	18,853	125	683,034	104,079	37,841	967	278,820	6,667	9,677	408,677	314,042	14,322,345	1,519,181	1,024,126	17,582	(34,543)

INDEX OF CONTENTS ON
USB FLASH DRIVE

UGI UTILITIES, INC. – GAS DIVISION
2022 BASE RATE CASE
DOCKET NO. R-2021-3030218

INDEX OF CONTENTS ON USB FLASH DRIVE

USB FLASH DRIVE

BOOK II

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

SUPPLEMENTAL DATA REQUESTS – COST OF SERVICE
SUPPLEMENTAL DATA REQUESTS – RATE OF RETURN
SUPPLEMENTAL DATA REQUESTS – REVENUE REQUIREMENTS

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 Effective: March 29, 2022

SUPPLEMENTAL DATA REQUESTS – COST OF SERVICE

SDR-COS-1

Request:

Please explain the Company's policy with regard to when customer advances and contributions in aid of construction must be made.

Response:

An advance or contribution in aid of construction is required from an Extension Applicant or Customer when insufficient revenues will be derived from the Extension Applicant or Customer to warrant the investment by the company. Please see UGI Gas Exhibit F, Rule 5, Extension Regulation, of the Company's current tariff.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-COS-2

Request:

Please provide a detailed explanation describing how contributions in aid of construction and customer advances are reflected in the Company's cost of service study.

Response:

Contributions in aid of construction are reflected as a deduction to rate base and included in Exhibit D. UGI Gas does not have any customer advances and no claim is made for customer advances.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-COS-3

Request:

Please provide a breakdown of contributions in aid of construction by customer class and plant account number for the most recent year available.

Response:

Please reference Attachment SDR-COS-3.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
CONTRIBUTIONS IN AID OF CONSTRUCTION BY CUSTOMER CLASSIFICATION AND PLANT ACCOUNT
FOR THE YEAR ENDED SEPTEMBER 30, 2021

Customer Class	Plant Account		Historic Test Year
Residential	107		$ 308,839
	376		1,079,509
	380		401,600
	381		9,714
	382		19,928
		Subtotal	$ 1,819,591
Commercial	107		$ 1,765,259
	376		1,716,026
	380		1,758,046
	382		2,328
		Subtotal	$ 5,241,658
Industrial	107		$ 8,723,804
	376		547,474
	380		13,595
	381		30,000
		Subtotal	$ 9,314,873
		Total	$ 16,376,123

SDR-COS-4

Request:

Please provide a breakdown of transmission and distribution mains investment by pipe diameter.

Response:

Please see Attachment SDR-COS-4.

Prepared by or under the supervision of: Constance E. Heppenstall

UGI UTILITES, INC. - GAS DIVISION
MAINS SIZE AND ORIGINAL COSTS
ACCOUNTS 367 AND 376
AS OF SEPTEMBER 30, 2021

Account 367 - Transmission

Type	Size (Inches)	Original Cost $	
Mains			
	16	$	18,179
	14		234,989
	12.75		569,063
	12		3,439,567
	11.625		2,740
	10.75		1,816,231
	10		545,723
	9.625		26,095
	8.625		1,958,550
	8		12,112,784
	7		29,545
	6.625		4,709,260
	6.25		20,665
	6		5,954,135
	5.625		15,088
	5.5625		25,555
	5.5		47,518
	5.375		19,325
	5.1875		298
	5		271,374
	4.5		499,795
	4.25		802
	4		6,008,956
	3		298,696
	2.5		6,322
	2		157,122
	1.5		42
	1.25		3,076
	1		638
	0.75		164
Total		$	38,792,292
Valves			
	14	$	19,153
	10		31,507
	8		154,607
	6		72,110
	2		487
	1		4,340
		$	282,204
Total Transmission Mains & Valves		$	39,074,497

UGI UTILITES, INC. - GAS DIVISION
MAINS SIZE AND ORIGINAL COSTS
ACCOUNTS 367 AND 376
AS OF SEPTEMBER 30, 2021

Account 376 - Distribution

Type	Size (Inches)	Original Cost $
Mains		
	30	$ 8,045
	24	53,844,450
	20	1,487,915
	16	40,045,046
	14	78,202
	12	167,397,594
	10.75	35
	10	11,012,298
	8	273,452,498
	7	274,232
	6.625	522,623
	6.25	4,198
	6	248,762,277
	5.625	864
	5	347,827
	4.875	831
	4.5	34,045
	4.25	1,716
	4	396,823,153
	3.5	38,374
	3	38,879,317
	2.5	36,106
	2	608,984,898
	1.5	28,481
	1.25	58,874,314
	1	4,945,624
	0.75	540,114
	0.625	1,798
	0.5	558,906
	0.25	6,377
		$ 1,906,992,159
Valves		
	24	$ 917
	16	1,559,818
	12	2,479,044
	10	480,169
	8	3,426,579
	6	2,823,157
	4	4,259,964
	3	775,127
	2.5	80
	2	5,023,030
	1.5	257
	1.25	250,669
	1	32,656
	0.75	1,901
	0.5	16,693
		$ 21,130,061
Total Distribution Mains & Valves		$ 1,928,122,220

SDR-COS-5

Request:

Please provide a breakdown of customer advances by customer class for the most recent year available.

Response:

The Company did not have any customer advances for the Fiscal Year ended September 30, 2021.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-COS-6

Request:

Please provide a breakdown of services investment by service line diameter, and a breakdown of services by size and customer class.

Response:

Please see Attachment SDR-COS-6.

Prepared by or under the supervision of: Constance E. Heppenstall

UGI UTILITIES, INC. - GAS DIVISION
Service Size and Original Cost
Account 380
As of September 30, 2021

Service Size	R/RT	N/NT	DS	LFD	Interruptible	XD Firm	Total
10"	$ 20,499	$ 13,666	$ -	$ -	$ -	$ -	$ 34,164
8"	96,199	432,895	-	96,199	288,597	192,398	1,106,288
6"	151,874	1,366,866	577,121	850,494	364,498	151,874	3,462,727
4"	543,080	6,652,728	1,535,245	1,242,817	605,743	31,332	10,610,944
3"	309,266	2,952,992	339,195	149,645	29,929	-	3,781,027
2.5"	2,950	4,916	-	-	-	-	7,866
2"	8,113,164	25,290,323	2,141,591	790,878	302,133	13,329	36,651,419
1.5"	58,136	13,656	-	390	-	-	72,182
1.25"	47,055,764	10,563,027	222,392	46,759	49,040	5,702	57,942,685
1"	601,538,067	89,384,926	350,691	58,448	24,067	6,876	691,363,076
0.75"	42,285,697	4,446,505	21,501	5,375	4,181	597	46,763,856
0.5"	441,287,719	16,041,976	26,347	4,940	1,647	-	457,362,629
0.25"	502,623	100,224	1,126	-	375	-	604,348
Total	$ 1,141,965,038	$ 157,264,701	$ 5,215,208	$ 3,245,947	$ 1,670,210	$ 402,109	$ 1,309,763,212

SDR-COS-7

Request:

If available, please provide a breakdown of meter investment by meter size, and a breakdown of meters by size and customer class.

Response:

Please see Attachment SDR-COS-7.

Prepared by or under the supervision of: Constance E. Heppenstall

UGI UTILITIES, INC. - GAS DIVISION
METER SIZE AND ORIGINAL COST
ACCOUNT 381 and 385
AS OF SEPTEMBER 30, 2021

Meter Size	R/RT	N/NT	DS	LFD	Interruptible	XD Firm	Total
Diaphragm 1000-Series	$ 319,307	$ 16,615,943	$ 540,180	$ 52,818	$ 96,032	$ -	$ 17,624,280
Diaphragm 1400-Series	50,261	9,015,614	980,095	150,784	144,501	6,283	10,347,538
Diaphragm 200-Series	67,120,374	3,587,453	671	-	-	112	70,708,611
Diaphragm 2300-Series	6,887	2,844,473	943,566	275,494	130,860	13,775	4,215,054
Diaphragm 300-Series	1,096,989	519,967	223	-	-	-	1,617,179
Diaphragm 400-Series	3,295,164	5,074,505	5,022	264	793	264	8,376,013
Diaphragm 5000-Series	9,254	2,470,793	1,526,895	795,836	166,570	-	4,969,349
Diaphragm 800-Series 10Ft	769,394	3,330,620	6,839	-	-	-	4,106,853
Diaphragm 800-Series 2Ft	807,302	3,784,805	9,209	-	-	-	4,601,316
Diaphragm 800-Series 5Ft	265,299	9,462,323	234,539	15,380	11,535	-	9,989,075
Rotary 1.5M	-	280,027	-	14,001	-	-	294,029
Rotary 11C	-	140,031	8,237	-	-	-	148,268
Rotary 11M	-	879,349	1,041,335	1,029,764	208,267	46,282	3,204,997
Rotary 15C	-	57,975	3,051	-	-	-	61,026
Rotary 16M	-	465,822	381,127	1,044,571	338,780	42,347	2,272,647
Rotary 23M	-	-	7,818	31,270	15,635	-	54,723
Rotary 38M	-	101,243	-	-	-	-	101,243
Rotary 3M	16,483	2,938,015	506,839	94,775	65,930	4,121	3,626,162
Rotary 4IN-IRM3	-	-	-	-	-	32,806	32,806
Rotary 5M	-	2,652,791	1,176,504	418,564	209,282	11,313	4,468,454
Rotary 7M	-	3,119,738	2,350,487	1,282,084	256,417	106,840	7,115,566
Rotary 8C125	-	7,095	-	-	-	-	7,095
Rotary 8C175	-	28,972	-	-	-	-	28,972
Rotary ROM2000	-	15,502	-	-	-	-	15,502
Turbine 3 Inch	-	38,019	38,019	50,693	25,346	-	152,078
Turbine 4 Inch	-	404,764	242,859	1,268,261	485,717	188,890	2,590,492
Turbine 6 Inch	-	308,777	154,389	926,331	988,086	370,532	2,748,115
Turbine 8 Inch	-	222,005	222,005	333,008	610,515	444,011	1,831,544
Ultrasonic 16" Flow Meter	-	-	-	-	-	136,962	136,962
Ultrasonic 800-Series	2,102,922	10,561,399	25,994	-	-	-	12,690,316
Total	$ 75,859,636	$ 78,928,022	$ 10,405,903	$ 7,783,898	$ 3,754,266	$ 1,404,538	$ 178,136,264

SDR-COS-8

Request:

Please provide the Company's rate design models and cost of service study on an IBM PC-compatible computer disk in Lotus 1-2-3 or Quattro format. If the models consist of more than one file, please include information on all files on the disk and what they contain. If not available in Lotus 1-2-3 or Quattro format, please provide in ASCII format.

Response:

Please see UGI Gas Exhibit D (Cost of Service Study - Fully Projected Future Test Year) provided in electronic format on USB flash drive.

Prepared by or under the supervision of: Constance E. Heppenstall

SDR-COS-9

Request:

Please provide a copy of the Company's current customer extension policy. Provide a representative sample of the analyses conducted by the Company when deciding whether service to a new customer qualifies under the Company's customer extension policy.

Response:

The current customer extension policy is contained in UGI Gas Exhibit F, Rule 5, Extension Regulation, of the Company’s current tariff. Rules 5.1-5.4 and 5.8 describe the methodology to evaluate whether service to a new customer qualifies under the current extension policy.

Prepared by or under the supervision of: Christopher R. Brown

SDR-COS-10

Request:

Please provide a detailed supply and requirement schedule for the Company's three most recent annual peak days and for design day. The schedules should include deliveries by source and requirements by rate schedule. Identify sources and requirements for transportation customers separately. Also include the Company's daily sendout sheet for each peak day and applicable weather data.

Response:

Please see Attachment SDR-COS-10.

Prepared by or under the supervision of: Christopher R. Brown

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY SENDOUT BY RATE CLASS
FOR THE YEARS ENDED SEPTEMBER 30, 2019, 2020 and 2021
(MDTH)

	2018-2019 Mar 6 (MDTH)	2019-2020 Feb 14 (MDTH)	2020-2021 JAN 28 (MDTH)
RG	3.1	2.8	2.8
RH	398.5	400.2	374.0
CG	6.4	7.8	4.0
CH	151.7	166.1	135.7
IG	1.6	2.2	1.0
IH	6.6	8.2	6.4
PGC FIRM	567.9	587.3	523.9
RT (CHOICE)	35.9	33.2	43.8
NT (CHOICE)	71.9	70.7	79.3
DS	93.3	57.4	65.8
LFD	105.7	77.2	105.4
XD-F/CDS-F	515.7	514.8	554.7
FIRM TRANSPORTATION	822.2	753.3	849.0
INTERRUPTIBLE	236.5	223.9	156.5
TOTAL	1,626.5	1,564.5	1,529.4

UGI UTILITIES, INC. - GAS DIVISION
TEMPERATURE BY AREA
FOR THE YEARS ENDED SEPTEMBER 30, 2019, 2020 and 2021
(°F)

	3/6/2019	2/14/2020	1/28/2021
Reading/Harrisburg/Lehigh/Lancaster/Altoona	19	22	26
Wilkes-Barre/Scranton	15	13	19
Bradford	10	2	16

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY DISPATCH DATA
FOR YEAR ENDED SEPTEMBER 30, 2019
(DTH)

Actual For	**6-Mar-19**
System Sendout	
Daily Sendout	1,626,493
Month to Date Current Sendout	7,969,140
Daily Average Temperature Data	
Reading/Harrisburg/Lehigh/Lancaster	19
Wilkes-Barre/Scranton	15
Bradford	10

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY DISPATCH DATA
FOR YEAR ENDED SEPTEMBER 30, 2020
(DTH)

Actual For	**14-Feb-20**
System Sendout	
Daily Sendout	1,564,496
Month to Date Current Sendout	16,785,709
Daily Average Temperature Data	
Reading/Harrisburg/Lehigh/Lancaster	22
Wilkes-Barre/Scranton	13
Bradford	2

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY DISPATCH DATA
FOR YEAR ENDED SEPTEMBER 30, 2021
(DTH)

Actual For	**28-Jan-21**
System Sendout	
Daily Sendout	1,529,446
Month to Date Current Sendout	33,885,093
Daily Average Temperature Data	
Reading/Harrisburg/Lehigh/Lancaster	26
Wilkes-Barre/Scranton	19
Bradford	16

UGI UTILITIES, INC. - GAS DIVISION
PEAK DAY CAPACITY REQUIREMENTS AND SUPPLY OPTIONS
FOR YEAR ENDING SEPTEMBER 30, 2022
(DTH)

			2021-2022
Supplier	**Upstream Pipeline**	**Rate Schedule**	**(Projected)**
Columbia		SST / FSS	126,473
Columbia		FTS	121,932
Columbia		NTS	19,520
Texas Eastern		FT/FT-1	165,207
Texas Eastern		CDS	84,068
Texas Eastern	Dominion	FTS-5/GSSII	6,667
Texas Eastern	Dominion	FT / GSS I	2,000
Texas Eastern	Dominion	FT / GSS II	2,000
Texas Eastern		SS-1	7,659
Texas Eastern / UGI Energy Services		Delivered Supply	25,000
Transco		FT	42,538
Transco		FTF/FT	22,770
Transco		SS-2	33,120
Transco		GSS	59,378
Transco		LGA	1,035
Transco		PS-FT	5,073
Transco		LSS	7,518
Transco		FT-Pocono	2,000
Transco Sentinel			(7,000)
Transco / UGI Energy Services		Delivered Supply	134,163
Tennessee		FT	40,068
Tennessee		Delivered Supply	16,766
UGI Energy Services		Peaking Services	439,187
Supply TBD			28,291
LNG Supply			500
North Penn	Shell	Direct Connection	1,500
Dominion		FT	2,000
UGI Storage Company		NNS	8,792
Subtotal			**1,398,225**
Third Party Capacity - Large Customers			**678,691**
Total Firm Capacity			**2,076,916**

PGC-1 Requirements	892,343
CHOICE Requirements	229,227
Subtotal	**1,121,570**
Firm Transportation Requirements	**899,268**
Total Requirements	**2,020,838**

SDR-COS-11

Request:

Please provide copies of the Company's daily sendout sheets for November through March of the most recent heating season.

Response:

Please see Attachment SDR-COS-11.

Prepared by or under the supervision of: Christopher R. Brown

UGI UTILITIES, INC. - GAS DIVISION
DAILY SENDOUT
NOVEMBER 2020 - MARCH 2021
(DTH)

Nov 2020 Sendout		Dec 2020 Sendout		Jan 2021 Sendout		Feb 2021 Sendout		Mar 2021 Sendout	
11/1/2020	985,325	12/1/2020	1,160,164	1/1/2021	1,113,726	2/1/2021	1,325,635	3/1/2021	1,289,256
11/2/2020	1,092,803	12/2/2020	1,202,476	1/2/2021	1,060,965	2/2/2021	1,271,395	3/2/2021	1,305,929
11/3/2020	1,009,046	12/3/2020	1,099,798	1/3/2021	1,147,500	2/3/2021	1,238,612	3/3/2021	1,057,238
11/4/2020	909,415	12/4/2020	1,037,752	1/4/2021	1,109,255	2/4/2021	1,229,689	3/4/2021	1,248,134
11/5/2020	842,220	12/5/2020	1,145,551	1/5/2021	1,134,424	2/5/2021	1,201,521	3/5/2021	1,206,003
11/6/2020	772,190	12/6/2020	1,303,204	1/6/2021	1,210,493	2/6/2021	1,213,169	3/6/2021	1,162,901
11/7/2020	663,577	12/7/2020	1,331,052	1/7/2021	1,226,544	2/7/2021	1,378,978	3/7/2021	1,173,928
11/8/2020	667,984	12/8/2020	1,299,388	1/8/2021	1,249,160	2/8/2021	1,415,124	3/8/2021	1,084,326
11/9/2020	675,023	12/9/2020	1,254,275	1/9/2021	1,144,197	2/9/2021	1,368,990	3/9/2021	966,061
11/10/2020	625,273	12/10/2020	1,186,833	1/10/2021	1,170,506	2/10/2021	1,342,000	3/10/2021	894,214
11/11/2020	641,395	12/11/2020	1,060,988	1/11/2021	1,263,088	2/11/2021	1,413,353	3/11/2021	768,841
11/12/2020	828,986	12/12/2020	996,208	1/12/2021	1,225,632	2/12/2021	1,378,858	3/12/2021	851,226
11/13/2020	829,026	12/13/2020	1,082,770	1/13/2021	1,141,020	2/13/2021	1,369,244	3/13/2021	880,611
11/14/2020	854,366	12/14/2020	1,333,567	1/14/2021	1,121,054	2/14/2021	1,286,206	3/14/2021	1,071,956
11/15/2020	805,942	12/15/2020	1,427,325	1/15/2021	1,032,636	2/15/2021	1,289,173	3/15/2021	1,169,735
11/16/2020	872,661	12/16/2020	1,468,339	1/16/2021	1,058,548	2/16/2021	1,350,236	3/16/2021	1,145,206
11/17/2020	1,024,709	12/17/2020	1,338,250	1/17/2021	1,086,473	2/17/2021	1,378,976	3/17/2021	990,747
11/18/2020	1,149,972	12/18/2020	1,307,643	1/18/2021	1,154,281	2/18/2021	1,334,060	3/18/2021	1,041,915
11/19/2020	971,860	12/19/2020	1,244,980	1/19/2021	1,162,000	2/19/2021	1,307,459	3/19/2021	1,125,478
11/20/2020	757,695	12/20/2020	1,152,566	1/20/2021	1,369,978	2/20/2021	1,309,147	3/20/2021	946,746
11/21/2020	821,846	12/21/2020	1,158,015	1/21/2021	1,196,494	2/21/2021	1,217,774	3/21/2021	893,653
11/22/2020	908,971	12/22/2020	1,173,240	1/22/2021	1,268,420	2/22/2021	1,238,085	3/22/2021	898,364
11/23/2020	1,070,396	12/23/2020	1,111,561	1/23/2021	1,388,781	2/23/2021	1,204,614	3/23/2021	788,681
11/24/2020	1,041,950	12/24/2020	806,744	1/24/2021	1,338,240	2/24/2021	1,055,253	3/24/2021	800,380
11/25/2020	862,889	12/25/2020	1,148,161	1/25/2021	1,307,904	2/25/2021	1,190,265	3/25/2021	683,797
11/26/2020	713,924	12/26/2020	1,295,641	1/26/2021	1,302,444	2/26/2021	1,144,942	3/26/2021	688,318
11/27/2020	766,233	12/27/2020	1,152,506	1/27/2021	1,371,886	2/27/2021	1,074,162	3/27/2021	661,930
11/28/2020	876,330	12/28/2020	1,047,313	1/28/2021	1,529,446	2/28/2021	1,099,607	3/28/2021	830,867
11/29/2020	891,208	12/29/2020	1,183,746	1/29/2021	1,455,598			3/29/2021	988,383
11/30/2020	871,957	12/30/2020	1,103,946	1/30/2021	1,251,152			3/30/2021	783,418
		12/31/2020	1,136,132	1/31/2021	1,322,788			3/31/2021	865,688

SDR-COS-12

Request:

Please provide a copy of the load duration curve used by the Company for capacity planning purposes. Please also identify the numerical data points shown for each day on the curve.

Response:

Please see Book I, Appendix F, Attachment 14-2, of the 2021 1307(f) Purchased Gas Cost filing for UGI Gas at Docket No. R-2021-3025652 which can be found at https://www.puc.pa.gov/pcdocs/1702100.pdf.

Prepared by or under the supervision of: Christopher R. Brown

SDR-COS-13

Request:

Please provide the following for the Company's ten largest transportation customers during peak month of the most recent heating season:

a. actual consumption

b. volume delivered to the Company on their behalf, if applicable

c. daily nomination

Response:

Please see Attachment SDR-COS-13.

Prepared by or under the supervision of: Christopher R. Brown

UGI UTILITIES, INC. - GAS DIVISION
TEN LARGEST TRANSPORTATION CUSTOMERS DURING PEAK MONTH OF THE MOST RECENT HEATING SEASON
JANUARY 2021

	(a.)	(b. and c.)		(a.)	(b. and c.)		(a.)	(b. and c.)		(a.)	(b. and c.)		(a.)	(b. and c.)
Rate XD -	Actual	Volume Delivered /	**Rate XD -**	Actual	Volume Delivered /	**Rate XD -**	Actual	Volume Delivered /	**Rate XD -**	Actual	Volume Delivered /	**Rate XD -**	Actual	Volume Delivered /
Customer 2	Consumption (Mcf)	Daily Nomination (Mcf)	**Customer 9**	Consumption (Mcf)	Daily Nomination (Mcf)	**Customer 12**	Consumption (Mcf)	Daily Nomination (Mcf)	**Customer 16**	Consumption (Mcf)	Daily Nomination (Mcf)	**Customer 17**	Consumption (Mcf)	Daily Nomination (Mcf)
1/1/2021	5,574.7	0.0	1/1/2021	12,756.5	14,534.9	1/1/2021	3,338.1	3,982.8	1/1/2021	13,037.0	13,667.0	1/1/2021	10,830.0	10,420.4
1/2/2021	5,863.9	0.0	1/2/2021	8,833.4	14,534.9	1/2/2021	3,947.8	3,982.8	1/2/2021	12,888.0	13,564.5	1/2/2021	10,810.0	10,397.4
1/3/2021	6,084.4	0.0	1/3/2021	14,062.8	14,534.9	1/3/2021	7,281.8	6,403.1	1/3/2021	12,582.0	11,286.9	1/3/2021	10,870.0	10,052.8
1/4/2021	6,363.0	0.0	1/4/2021	11,416.3	14,534.9	1/4/2021	8,163.7	6,733.4	1/4/2021	12,170.0	10,391.7	1/4/2021	10,570.0	9,720.5
1/5/2021	5,794.4	0.0	1/5/2021	17,333.3	14,534.9	1/5/2021	8,817.1	6,894.3	1/5/2021	12,020.0	11,179.6	1/5/2021	10,620.0	10,340.0
1/6/2021	6,425.8	0.0	1/6/2021	18,730.4	19,298.4	1/6/2021	9,189.6	6,946.9	1/6/2021	12,869.0	12,137.0	1/6/2021	10,890.0	10,416.6
1/7/2021	6,595.8	9,932.2	1/7/2021	14,250.1	14,534.9	1/7/2021	9,592.5	6,834.9	1/7/2021	12,774.0	12,268.2	1/7/2021	10,910.0	10,435.7
1/8/2021	5,536.1	15,972.9	1/8/2021	0.0	0.0	1/8/2021	9,238.4	5,682.2	1/8/2021	12,667.0	11,936.9	1/8/2021	11,300.0	10,052.8
1/9/2021	5,455.9	0.0	1/9/2021	0.0	0.0	1/9/2021	7,502.8	4,602.2	1/9/2021	12,799.0	13,223.7	1/9/2021	11,200.0	10,654.0
1/10/2021	6,355.4	0.0	1/10/2021	0.0	0.0	1/10/2021	8,259.3	5,890.9	1/10/2021	12,967.0	12,565.0	1/10/2021	11,410.0	10,677.0
1/11/2021	6,486.1	0.0	1/11/2021	978.0	0.0	1/11/2021	9,359.8	7,021.6	1/11/2021	12,912.0	12,123.6	1/11/2021	9,900.0	10,435.7
1/12/2021	6,165.5	0.0	1/12/2021	47,018.8	49,220.9	1/12/2021	9,245.8	6,909.6	1/12/2021	12,582.0	13,689.0	1/12/2021	9,840.0	11,010.2
1/13/2021	6,674.7	0.0	1/13/2021	0.0	0.0	1/13/2021	9,211.9	7,659.2	1/13/2021	12,560.0	13,756.0	1/13/2021	11,010.0	11,488.9
1/14/2021	6,363.9	0.0	1/14/2021	26,108.5	23,976.7	1/14/2021	9,549.9	8,616.7	1/14/2021	13,029.0	13,398.9	1/14/2021	11,020.0	11,967.6
1/15/2021	5,703.1	0.0	1/15/2021	0.0	0.0	1/15/2021	7,917.8	8,808.1	1/15/2021	10,804.0	13,266.8	1/15/2021	10,930.0	11,967.6
1/16/2021	5,474.1	0.0	1/16/2021	0.0	0.0	1/16/2021	6,983.0	8,616.7	1/16/2021	12,778.0	14,333.3	1/16/2021	10,860.0	12,738.3
1/17/2021	5,754.0	0.0	1/17/2021	0.0	0.0	1/17/2021	8,305.6	8,616.7	1/17/2021	12,591.0	13,921.6	1/17/2021	10,940.0	12,741.2
1/18/2021	6,134.7	5,517.9	1/18/2021	0.0	0.0	1/18/2021	9,214.7	8,616.7	1/18/2021	11,614.0	12,273.0	1/18/2021	9,420.0	12,003.0
1/19/2021	5,834.4	0.0	1/19/2021	338.6	0.0	1/19/2021	8,266.1	8,616.7	1/19/2021	11,614.0	12,273.0	1/19/2021	8,840.0	12,165.8
1/20/2021	6,515.9	12,584.7	1/20/2021	79,608.2	75,229.7	1/20/2021	8,945.4	7,946.5	1/20/2021	11,615.0	12,706.7	1/20/2021	10,930.0	11,488.9
1/21/2021	6,894.3	6,873.2	1/21/2021	59,477.9	54,079.5	1/21/2021	7,829.5	8,616.7	1/21/2021	11,341.0	12,496.1	1/21/2021	10,660.0	11,010.2
1/22/2021	6,324.8	7,260.4	1/22/2021	84,502.0	81,836.2	1/22/2021	7,380.9	8,042.2	1/22/2021	11,470.0	12,382.1	1/22/2021	10,630.0	11,010.2
1/23/2021	6,177.1	8,228.5	1/23/2021	85,535.5	80,617.2	1/23/2021	7,123.9	7,850.7	1/23/2021	4,697.0	9,458.2	1/23/2021	10,280.0	11,782.8
1/24/2021	6,186.0	8,228.5	1/24/2021	84,928.4	80,627.9	1/24/2021	8,129.2	7,850.7	1/24/2021	2,459.0	9,393.1	1/24/2021	11,150.0	11,465.9
1/25/2021	6,875.4	8,228.5	1/25/2021	84,875.6	86,735.5	1/25/2021	9,159.2	7,850.7	1/25/2021	9,376.0	9,031.2	1/25/2021	10,440.0	11,488.9
1/26/2021	6,115.3	0.0	1/26/2021	83,014.0	92,262.6	1/26/2021	9,035.6	6,969.9	1/26/2021	11,434.0	4,114.0	1/26/2021	9,900.0	10,435.7
1/27/2021	7,185.5	0.0	1/27/2021	85,665.7	88,125.0	1/27/2021	9,453.6	7,180.5	1/27/2021	12,217.0	10,363.0	1/27/2021	10,930.0	10,052.8
1/28/2021	6,690.6	0.0	1/28/2021	86,216.8	87,317.8	1/28/2021	9,232.0	8,137.9	1/28/2021	11,388.0	11,629.6	1/28/2021	10,680.0	10,052.8
1/29/2021	6,220.5	0.0	1/29/2021	43,822.3	45,452.5	1/29/2021	7,918.4	7,467.8	1/29/2021	10,887.0	11,860.3	1/29/2021	11,600.0	11,359.6
1/30/2021	6,568.1	0.0	1/30/2021	0.0	0.0	1/30/2021	6,203.5	7,467.8	1/30/2021	2,326.0	12,692.3	1/30/2021	11,540.0	11,010.2
1/31/2021	5,948.6	0.0	1/31/2021	950.5	0.0	1/31/2021	7,921.8	7,467.8	1/31/2021	0.0	12,820.6	1/31/2021	11,320.0	12,233.7
Total	192,342.0	82,826.8	Total	950,423.6	951,989.3	Total	251,718.7	224,284.7	Total	336,467.0	370,202.9	Total	332,230.0	343,077.2

	(a.)	(b. and c.)		(a.)	(b. and c.)		(a.)	(b. and c.)		(a.)	(b. and c.)		(a.)	(b. and c.)
Rate XD -	Actual	Volume Delivered /	**Rate XD -**	Actual	Volume Delivered /	**Rate XD -**	Actual	Volume Delivered /	**Rate XD -**	Actual	Volume Delivered /	**Rate XD -**	Actual	Volume Delivered /
Customer 28	Consumption (Mcf)	Daily Nomination (Mcf)	**Customer 39**	Consumption (Mcf)	Daily Nomination (Mcf)	**Customer 48**	Consumption (Mcf)	Daily Nomination (Mcf)	**Customer 50**	Consumption (Mcf)	Daily Nomination (Mcf)	**Customer 53**	Consumption (Mcf)	Daily Nomination (Mcf)
1/1/2021	217,497.7	203,291.4	1/1/2021	128,034.9	128,034.9	1/1/2021	39,180.0	39,180.0	1/1/2021	5,366.0	2,415.3	1/1/2021	8,268.0	8,500.5
1/2/2021	217,265.0	216,844.1	1/2/2021	127,247.1	127,247.1	1/2/2021	38,940.0	38,940.0	1/2/2021	99.8	0.0	1/2/2021	8,408.0	8,518.9
1/3/2021	216,258.6	216,844.1	1/3/2021	128,793.6	128,793.6	1/3/2021	39,231.0	39,231.0	1/3/2021	4,368.0	0.0	1/3/2021	8,583.0	8,518.9
1/4/2021	213,972.2	216,844.1	1/4/2021	125,663.8	125,663.8	1/4/2021	37,950.0	37,950.0	1/4/2021	2,324.6	3,831.6	1/4/2021	8,482.0	8,518.9
1/5/2021	214,456.1	212,971.9	1/5/2021	123,512.6	123,512.6	1/5/2021	36,815.0	36,815.0	1/5/2021	93.0	0.0	1/5/2021	8,446.0	8,491.8
1/6/2021	217,574.4	212,971.9	1/6/2021	124,714.1	124,714.1	1/6/2021	38,318.0	38,318.0	1/6/2021	99.0	0.0	1/6/2021	8,439.0	8,518.9
1/7/2021	218,666.2	212,971.9	1/7/2021	128,920.5	128,920.5	1/7/2021	39,794.0	39,794.0	1/7/2021	95.8	0.0	1/7/2021	8,515.0	8,296.2
1/8/2021	218,746.7	216,844.1	1/8/2021	127,118.2	127,118.2	1/8/2021	40,648.0	40,648.0	1/8/2021	99.0	0.0	1/8/2021	8,552.0	8,502.4
1/9/2021	215,826.8	216,844.1	1/9/2021	124,851.7	124,851.7	1/9/2021	39,899.0	39,899.0	1/9/2021	99.0	0.0	1/9/2021	8,602.0	8,518.9
1/10/2021	215,848.9	216,844.1	1/10/2021	122,258.7	122,258.7	1/10/2021	39,939.0	39,939.0	1/10/2021	5,196.2	3,864.5	1/10/2021	8,555.0	8,518.9
1/11/2021	217,643.0	216,844.1	1/11/2021	128,985.5	128,985.5	1/11/2021	38,392.0	38,392.0	1/11/2021	201.8	0.0	1/11/2021	8,768.0	8,518.9
1/12/2021	217,405.0	216,844.1	1/12/2021	127,470.0	127,470.0	1/12/2021	38,044.0	38,044.0	1/12/2021	5,777.2	3,864.5	1/12/2021	8,604.0	8,518.9
1/13/2021	212,730.8	216,844.1	1/13/2021	120,347.9	120,347.9	1/13/2021	37,122.0	37,122.0	1/13/2021	308.2	0.0	1/13/2021	7,918.0	8,390.1
1/14/2021	215,423.5	216,844.1	1/14/2021	124,891.5	124,891.5	1/14/2021	37,798.0	37,798.0	1/14/2021	29.6	0.0	1/14/2021	8,471.0	8,518.9
1/15/2021	213,958.0	212,003.9	1/15/2021	127,428.3	127,428.3	1/15/2021	37,779.0	37,779.0	1/15/2021	24.2	0.0	1/15/2021	8,822.0	7,801.5
1/16/2021	213,537.8	214,908.0	1/16/2021	128,568.8	128,568.8	1/16/2021	36,959.0	36,959.0	1/16/2021	29.4	0.0	1/16/2021	8,812.0	8,518.9
1/17/2021	215,356.7	212,971.9	1/17/2021	128,230.6	128,230.6	1/17/2021	37,752.0	37,752.0	1/17/2021	68.4	0.0	1/17/2021	8,615.0	8,518.9
1/18/2021	215,193.1	214,908.0	1/18/2021	126,097.9	126,097.9	1/18/2021	39,265.0	39,265.0	1/18/2021	102.8	0.0	1/18/2021	8,218.0	8,518.9
1/19/2021	216,343.5	214,908.0	1/19/2021	127,702.5	127,702.5	1/19/2021	38,373.0	38,373.0	1/19/2021	110.8	0.0	1/19/2021	7,966.0	8,518.9
1/20/2021	218,018.2	214,908.0	1/20/2021	128,526.2	128,526.2	1/20/2021	39,808.0	39,808.0	1/20/2021	126.6	0.0	1/20/2021	7,631.0	8,518.9
1/21/2021	212,847.0	214,908.0	1/21/2021	128,119.2	128,119.2	1/21/2021	36,362.0	36,362.0	1/21/2021	114.2	0.0	1/21/2021	8,186.0	8,518.9
1/22/2021	217,653.0	214,908.0	1/22/2021	126,329.5	126,329.5	1/22/2021	36,958.0	36,958.0	1/22/2021	106.0	0.0	1/22/2021	7,879.0	8,518.9
1/23/2021	217,545.8	214,908.0	1/23/2021	129,796.5	129,796.5	1/23/2021	40,282.0	40,282.0	1/23/2021	116.0	0.0	1/23/2021	7,939.0	8,518.9
1/24/2021	218,250.5	214,908.0	1/24/2021	129,937.0	129,937.0	1/24/2021	41,400.0	41,400.0	1/24/2021	114.0	0.0	1/24/2021	7,829.0	8,518.9
1/25/2021	217,456.5	214,908.0	1/25/2021	128,160.9	128,160.9	1/25/2021	38,953.0	38,953.0	1/25/2021	109.8	0.0	1/25/2021	7,808.0	8,518.9
1/26/2021	216,193.7	216,844.1	1/26/2021	129,690.9	129,690.9	1/26/2021	38,366.0	38,366.0	1/26/2021	3,454.4	3,864.5	1/26/2021	8,138.0	8,518.9
1/27/2021	220,051.0	216,844.1	1/27/2021	130,442.8	130,442.8	1/27/2021	40,078.0	40,078.0	1/27/2021	2,121.4	0.0	1/27/2021	8,086.0	8,518.9
1/28/2021	218,940.6	216,844.1	1/28/2021	127,400.2	127,400.2	1/28/2021	41,468.0	41,468.0	1/28/2021	25,331.4	23,656.4	1/28/2021	8,312.0	8,518.9
1/29/2021	218,070.9	214,908.0	1/29/2021	108,635.7	108,635.7	1/29/2021	42,172.0	42,172.0	1/29/2021	14,964.6	18,356.2	1/29/2021	7,977.0	8,505.3
1/30/2021	217,747.1	214,908.0	1/30/2021	115,628.9	115,628.9	1/30/2021	41,165.0	41,165.0	1/30/2021	5.6	0.0	1/30/2021	8,672.0	8,518.9
1/31/2021	217,931.3	214,908.0	1/31/2021	126,927.3	126,927.3	1/31/2021	40,167.0	40,167.0	1/31/2021	8,429.6	6,762.8	1/31/2021	8,050.0	8,330.1
Total	6,714,409.6	6,665,052.2	Total	3,910,433.3	3,910,433.3	Total	1,209,377.0	1,209,377.0	Total	79,486.4	66,615.8	Total	257,551.0	262,752.6

SDR-COS-14

Request:

Please provide a summary identifying the salient features of each of the following. Salient features include contract party, effective term and applicable contract quantities (daily, annual, seasonal, etc.).

a. All firm transportation agreements by type greater than one month in length. Indicate whether the capacity is available at the Company's citygate to meet design day requirements or is upstream capacity. Identify the downstream pipeline for each upstream arrangement.

b. All firm storage, gathering and exchange agreements. Indicate if each agreement provides design day capacity at the citygate or requires separate transportation (identify) service to effectuate delivery. Include on-system storage and peak shaving facilities used by the Company and identify all ratcheting provisions applicable to the Company's contractual and on-system storage arrangements.

Response:

Please see Attachments SDR-COS-14(a) and SDR-COS-14(b). The contracts are reflected as of 11/1/2021.

Prepared by or under the supervision of: Christopher R. Brown

Pipeline	Rate Schedule	Contract ID	Contract Type	Term Start	Term End	MDQ	SCQ	Capacity Flow	Downstream Pipe
Columbia	FSS	79028	Storage	11/1/2004	3/31/2025	126,473	7,050,541	Upstream	Columbia
Columbia	FTS	46284	Transport	11/1/1993	10/31/2023	50,412		City Gate	
Columbia	FTS	78653	Transport	5/15/2004	10/31/2029	42,000		City Gate	
Columbia	FTS	80021	Transport	11/1/2004	10/31/2025	21,500		City Gate	
Columbia	FTS	80095	Transport	11/1/2004	3/31/2024	18,020		City Gate	
Columbia	FTS	80835	Transport	11/1/2004	10/31/2023	3,738		City Gate	
Columbia	NTS	80837	Transport	11/1/2004	10/31/2024	15,000		City Gate	
Columbia	SST	79133	Transport	11/1/2004	3/31/2025	126,473		City Gate	
Columbia	FTS	229154	Transport	11/1/2004	3/31/2025	7,750		City Gate	
Columbia	FTS	230222	Transport	11/1/2012	10/31/2024	10,782		City Gate	
Columbia	NTS	230215	Transport	11/1/2012	3/31/2024	4,520		City Gate	
Columbia	FTS	230211	Transport	11/1/2004	10/31/2023	2,432		City Gate	
Columbia	FTS	230212	Transport	11/1/2019	10/31/2023	2,432		City Gate	
Columbia	FTS	230213	Transport	11/1/2019	10/31/2023	2,432		City Gate	
Columbia	FTS	230214	Transport	11/1/2019	10/31/2023	2,434		City Gate	
EGTS	FT	5H0743	Transport	1/1/2005	12/31/2022	2,000		City Gate	
EGTS	FT	5G1773	Transport	11/1/1998	3/31/2024	2,000		Upstream	TETCO
EGTS	GSS	5F5363	Storage	11/1/1998	3/31/2024	2,000	200,000	Upstream	Transco/TETCO
EGTS	GSS	5F5362	Storage	11/1/1998	3/31/2024	2,000	200,000	Upstream	TETCO
EGTS	GSS	300126	Storage	11/1/1998	3/31/2024	6,667	666,667	Upstream	TETCO
Tennessee	FT-G	62498	Transport	9/1/1993	10/31/2025	Variable - 400 dth/d to 1,200 dth/d		City Gate	
Tennessee	FT-G	62499	Transport	9/1/1993	10/31/2025	Variable - 0 dth/d to 2,054 dth/d		City Gate	
Tennessee	FT-A	301692	Transport	11/1/2014	10/31/2029	34,000		City Gate	
Tennessee	FT-A	362539	Transport	11/1/2020	10/31/2032	3,183		City Gate	
TETCO	CDS	800239	Transport	6/1/1993	10/31/2023	25,000		City Gate	
TETCO	CDS	800397	Transport	11/1/1993	10/31/2023	41,000		City Gate	
TETCO	CDS	820019	Transport	11/1/2000	10/31/2023	10,000		City Gate	
TETCO	Flex-X	800504	Transport	11/1/1995	10/31/2023	4,000		City Gate	
TETCO	FT-1	800240	Transport	6/1/1993	10/31/2023	25,000		City Gate	
TETCO	FT-1	800373	Transport	11/1/1994	10/31/2024	20,000		City Gate	
TETCO	FT-1	800394	Transport	11/1/1993	10/31/2023	32,475		City Gate	
TETCO	FT-1	800468	Transport	11/1/1995	10/31/2024	10,000		City Gate	
TETCO	FT-1	830067	Transport	12/1/1999	10/31/2024	10,000		City Gate	
TETCO	FT-1	910181	Transport	11/1/2004	10/31/2023	12,000		City Gate	
TETCO	FT-1	910417	Transport	11/1/2003	10/31/2023	11,713		City Gate	
TETCO	FTS-5	330910	Transport	6/1/1993	3/31/2023	6,667		City Gate	
TETCO	FT-1	911580	Transport	11/1/1994	4/15/2023	5,880		City Gate	
TETCO	CDS	800376	Transport	10/1/1993	10/31/2025	8,068		City Gate	
TETCO	FT-1	800404	Transport	11/1/1994	10/31/2025	1,136		City Gate	
TETCO	FT-1	830060	Transport	3/24/1999	11/30/2025	4,000		City Gate	
TETCO	FT-1	911777	Transport	11/1/2021	10/31/2036	18,000		City Gate	
TETCO	FT-1	911153	Transport	11/1/2014	10/31/2025	3,300		Upstream	Columbia
TETCO	SS-1	400190	Storage	5/1/1994	4/30/2026	7,659	541,911	City Gate	
Transco	FT	1005004	Transport	8/1/1991	3/31/2027	1,346		City Gate	
Transco	FT	1002594	Transport	2/1/1992	3/31/2024	5,072		City Gate	
Transco	FT	1002595	Transport	4/10/1990	3/31/2024	2,081		City Gate	
Transco	FT	1013596	Transport	10/1/1996	3/31/2027	22,770		City Gate	
Transco	FT	9089608	Transport	11/1/2009	10/31/2029	7,000		City Gate	
Transco	FT	9180223	Transport	12/1/2015	7/31/2024	12,279		City Gate	
Transco	FT-PS	1004999	Transport	8/1/1991	3/31/2025	3,416		City Gate	
Transco	FT-Pocono	1021106	Transport	11/1/1997	10/31/2027	500		City Gate	
Transco	FT	1003692	Transport	2/1/1992	3/31/2024	8,328		City Gate	
Transco	FT-PS	1005005	Transport	8/1/1991	7/31/2026	311		City Gate	
Transco	FT	1006503	Transport	10/1/1993	10/31/2024	4,566		City Gate	
Transco	FT	1012119	Transport	11/16/1995	3/31/2024	828		City Gate	
Transco	FT-Pocono	1021107	Transport	11/1/1997	3/31/2025	1,500		City Gate	
Transco	FT-LS	9250893	Transport	10/19/2021	10/18/2036	2,400		City Gate	
Transco	GSS	1000798	Storage	7/1/1996	3/31/2028	56,532	2,746,576	City Gate	
Transco	LSS	1000796	Storage	10/1/1993	3/31/2028	7,518	827,053	City Gate	
Transco	SS-2	1004032	Storage	4/1/1990	3/31/2028	25,875	2,846,250	City Gate	
Transco	ESS	9162496	Storage	11/1/1993	10/31/2024	10,000	83,847	Upstream	Transco
Transco	GSS	1000749	Storage	7/1/1996	3/31/2028	1,744	102,129	City Gate	
Transco	SS2	1003973	Storage	7/25/1990	3/31/2028	7,245	796,950	City Gate	
Transco	GSS	1000780	Storage	7/1/1996	3/31/2028	1,102	57,881	City Gate	
Transco	LG-A	1000783	Storage	11/1/1974	3/31/2025	1,035	4,140	City Gate	
UGI Storage Company	NNS	NNS-1	Transport	4/1/2011	3/31/2026	8,792		City Gate	
UGI Storage Company	FSS	FSS-1	Storage	4/1/2011	3/31/2026	8,792	879,200	City Gate	
Supplier A		N/A	Delivered Supply	12/1/2020	3/31/2026	600		City Gate	
Supplier A		N/A	Delivered Supply	12/1/2021	3/31/2024	10,000		City Gate	

Pipeline	Rate Schedule	Contract ID	Contract Type	Term Start	Term End	MDQ	SCQ	Capacity Flow	Downstream Pipe
Supplier B		N/A	Delivered Supply	11/1/2014	10/31/2020	1,500		City Gate	
Supplier C		N/A	Delivered Supply	11/1/2018	10/31/2023	16,766		City Gate	
UGI Energy Services		UGI-CO-1014	Delivered Supply	11/1/2021	10/31/2036	25,000		City Gate	
UGI Energy Services		UGIN-CO-1012	Delivered Supply	11/1/2018	10/31/2033	36,169		City Gate	
UGI Energy Services		UGI-CO-1013	Delivered Supply	11/1/2020	10/31/2038	97,994		City Gate	
UGI Energy Services		UGIU-P-1010	Peaking	11/1/2015	3/31/2020	106,465		City Gate	
UGI Energy Services		UGIU-P-1012	Peaking	11/1/2016	3/31/2021	23,632		City Gate	
UGI Energy Services		UGIU-P-1014	Peaking	11/1/2018	3/31/2033	40,573		City Gate	
UGI Energy Services		UGIU-P-1016	Peaking	11/1/2021	3/31/2036	162,177		City Gate	
UGI Energy Services		UGIU-P-1017	Peaking	11/1/2021	3/31/2036	72,299		City Gate	
UGI Energy Services		UGIU-P-1018	Peaking	12/1/2021	3/31/2024	15,891		City Gate	
UGI Energy Services		CPG-P-1006	Peaking	11/1/2015	3/31/2025	4,750		City Gate	
UGI Energy Services		CPG-P-1007	Peaking	11/1/2018	3/31/2033	5,000		City Gate	
UGI Energy Services		CPG-P-1008	Peaking	11/1/2018	3/31/2033	2,519		City Gate	
UGI Energy Services		PNG-P-1003	Peaking	11/1/2016	3/31/2026	21,772		City Gate	

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
COLUMBIA	**FSS**	7,050,541	126,473	MDIQ = 1/25 of monthly maximum and	YEAR	**126,473**	**39**	MDWQ =100% if % if gas in storage is >30%	56	YEAR	
	79028			Nov and Dec = 1/30 of monthly maximum	ROUND	**101,178**	**6**	80% MDWQ if gas in storage is <30% and >20%		ROUND	sec.4/ p.90-92
				MAXIMUM MONTHLY INJECTIONS -		**82,207**	**8**	65% MDWQ if gas in storage is <20% and >10%			
				Apr=15%; May thru July = 20%;		**63,236**	**11**	50% MDWQ if gas in storage is <10% and >0%			
				August= 18%: Sept = 13%; Oct=9%; Nov=5%;		**9,458**	**1**	last withdrawal to empty field			
				Dec thru Mar= 10%		**Total**	**65**	MAXIMUM MONTHLY WITHDRAWALS -			
								NOV DEC JAN - 40% OF SCQ			
								FEB - 30% OF SCQ			
	INJ RULES:	1) Subject to minimum and maximum daily and monthly injection limits.						MAR - 20% OF SCQ			sec.4/ p.90
		2) Excess must be requested 24hrs in advance						MINIMUM MONTHLY WITHDRAWALS -			sec.4/ p.90
	WDL RULES:	1) Subject to minimum and maximum daily and monthly withdrawals limits						FEB - 10% OF SCQ			sec.4/ p.92
		2) Excess must be requested 24hrs in advance						MAR - 10% OF SCQ			sec.4/ p.92
	Seasonal Rules	1) Subject to seasonal maximum inventory levels: no more than 60% of SCQ on 6/30 and no more than 85% of SCQ on 8/31									sec.4/ p.91
		2) Subject to seasonal maximum inventory levels: no more than 25% of SCQ on 4/1 and no more than 65% of SCQ on 2/1									sec.4/ p.93
	Overrun	1) DAILY PENALTY based on the higher of: (i) a price per Dth equal to three times the midpoint of the range of prices reported for "Columbia Gas, Appalachia" as published in Platts Gas Daily price survey or (ii) a price per Dth equal to 150 percent									sec.4/ p.95
		of the highest midpoint posting for either: Mich Con City-gate, Transco, Zone 6 Non-N.Y., or Texas Eastern, M-2 Receipts as published in Platts Gas Daily price survey for all quantities taken in excess of its Lowered Quantity									sec.4/ p.96
		2) DAILY OFO PENALTY based on the higher of: (i) a price per Dth equal to three times the midpoint of the range of prices reported for "Columbia Gas, Appalachia" as published in Platts Gas Daily price survey or (ii) a price per Dth equal to 150 percent									sec.4/ p.95
		of the highest midpoint posting for either: Mich Con City-gate, Transco, Zone 6 Non-N.Y., or Texas Eastern, M-2 Receipts as published in Platts GasDaily price survey shall be assessed to Shipper for all quantities in violation of that operational flow order									
		3) DAILY PENALTY = If injections exceed 110% of MDIQ, charge is $5 for all dth in excess of MDIQ									sec.4/ p.96
		4) MONTHLY PENALTY = If injections exceed 105% of MMIQ, charge is $5 for all dth in excess of 105%									sec.4/ p.96
		5) MONTHLY PENALTY = If withdrawls exceed monthly limits, charge is $5 for all dth in excess of limits									sec.4/ p.96
		6) DAILY PENALTY = If injections or withdrawals exceed SCQ or results in a negative balance, charge is $5 for all dth in excess ofSCQ									
		7) DAILY PENALTY = If unauthorized withdrawals > 103% of MDWQ, charge is $10 for all dth can be reduced if paying matching transportation penalties									sec.4/ p.97
		8) Gas is forfeited to Pipeline if :a) OFO violation; b) failure to withdrawal monthly minimum; c)Failure to comply with April 1 limit									sec.4/ p.97
		9) June 30 and August 31 FSS Inventory levels are not enforcable except if TCO issues an OFO for that period per Brian Adams 6/18/2006									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
DOMINION	**GSS**	666,667	3,704	SUMMER : if storage balance < or = 1/2	YEAR	**6,667**	**65**	100% MDWQ if % if gas in storage is >35%	100	YEAR	
	300126		3,115	of capacity then 1/180 of capacity;	ROUND	**6,134**	**21**	92% MDWQ if % if gas in storage is <35% and >16%		ROUND	
				if storage balance > or = 1/2 of capacity		**4,667**	**9**	70% MDWQ if % if gas in storage is <16% and >10%			
	(VIA FTS-5)			then 1/214 of capacity		**4,200**	**14**	63% MDWQ if % if gas in storage is <10% and >0%			
				WINTER : 1/214 of capacity		**3,695**	**1**	last withdrawal to empty field			
	INJ RULES:	1) Tariff injection tolerance = 115% of MDIQ Apr 1 thru Jul 31;				**Total**	**110**				
		= 107% in Aug; 102% in Sept and Oct									
		2) Excess injections may be requested, subject to exess charge									rate sheet 35
	WDL RULES:	1) Monthly limit : Dominion is required to deliver only 87.5% in any month									sec. 8.6/p.358
		2) Excess withdrawals may be requested, subject to excess charge									sht 35/sec. 9.1
	Seasonal Rules	1) Minimum turnover - By Apr 15, total withdrawals must be equal to or greater than the Nov 1 balance of preceeding year									sec. 8.7/p.358
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		2) Monthly minimum balances: Dec and Jan=35%; Feb=15%. Failure to maintain minimum levels will reduce withdrawal by 10%									sec. 8.5/p.358
	Overrun	1) Daily Injection Overruns - if uncorrected over tolerance then subject to Unauthorized Overrun Charge									rate sheet 39
		2) Storage Capacity Overruns - if not adjusted within 24hrs, then subject to Storage Gas Balance Unauthorized Overrun Charge									rate sheet 39
		3) Daily Withdrawal Overruns - if uncorrected over entitlement then subject to Unauthorized Withdrawal Overrun Charge									rate sheet 39
		4) Daily Withdrawal Overruns - if withdrawals exceed storage gas balance, then subject to $25/dth per day until gas is replaced									
		5) Failure to comply with Minimum Turnover, then subject to a charge of 2 times the effective fuel retention % by deducting the dth from the gas balance.									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**GSS**	102,129	567	0 -50% of Storage Cap Quantitiy =1/180	YEAR	**1744**	**38**	MDWQ =100% if % if gas in storage is >35%	59	YEAR	sec. 7.3a
	1000749		477	50-100% of Storage Cap Quantitiy =1/214	ROUND	**1,727**	**9**	99% of MDWQ if % if gas in storage is 20% to 35%		ROUND	
						1,291	**10**	74% of MDWQ if % if gas in storage is 7% to 20%			
						959	**7**	55% of MDWQ if % if gas in storage is 0% to7 %			
	INJ RULES:	1) Swing rate schedule				**374**	**1**	last withdrawal to empty field			
	WDL RULES:	1) Transco is required to deliver only 87.5% in any consecutive 30 day period				**Total**	**65**				sec 7.3b/p 115
		2) Transco is not obligated to deliver below 20% balance in Storage Capacity Quantity from Nov 1 thru Feb 14									sec 7.3c/p 115
		3) Transco is not obligated to deliver below 7% balance in Storage Capacity Quantity from Feb 15 thru Mar 1									sec 7.3c/p 115
	Seasonal Rules	1) Seasonal withdrawals must be Nov 1 balance by Apr 15									sec 7.3d/p 116
		2) Minimum inventory levels = Dec, Jan, 35%; Feb 15%; if not then obligation of storage demand will be reduced 5%									sec 7.3e/p 116
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		3) Minimum turnover - By Apr 1, total withdrawals must be equal to or greater than the Nov 1 balance of preceeding year									
		4) Subject to specific buyer OFO's to allow Transco manage GSS									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	**SS-2**	796,950	5,313	0 -10% of Storage Cap Quantitiy =1/150	4/1-10/31	**7,245**	**77**	>30 -100% of Annual Storage Volume in balance =1/110	110	11/1-3/31	
	1003973		4,981	>10-30% of Storage Cap Quantitiy =1/160		**6,641**	**18**	>15 -30% of Annual Storage Volume in balance =1/120			
			4,554	>30-50% of Storage Cap Quantitiy =1/175		**5,903**	**7**	>10 -15% of Annual Storage Volume in balance =1/135			
			4,308	>50-70% of Storage Cap Quantitiy =1/185		**5,313**	**14**	<10% of Annual Storage Volume in balance =1/150			
			3,985	>70-100% of Storage Cap Quantitiy =1/200		**3,844**	**1**	last withdrawal to empty field			
	INJ RULES:	1) Swing rate ability, subject to Sec. 18.1 of GT&C				**Total**	**117**				GT&C sec.18.1
	WDL RULES:	1) Swing rate ability, subject to Sec. 18.1 of GT&C									GT&C sec.18.1
	Seasonal Rules										

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	GSS	2,746,576	15,259	0 -50% of Storage Cap Quantity =1/180	YEAR	56,532	31	MDWQ =100% if % if gas in storage is >35%	49	1/1-12/31	sec. 7.3a
	1000798		12,834	50-100% of Storage Cap Quantity =1/214	ROUND	55,967	7	99% of MDWQ if % if gas in storage is 20% to 35%			
						41,834	9	74% of MDWQ if % if gas in storage is 7% to 20%			
						31,093	7	55% of MDWQ if % if gas in storage is 0% to7 %			
	INJ RULES:	1) Swing rate schedule				Total	54				
	WDL RULES:	1) Transco is required to deliver only 87.5% in any consecutive 30 day period									sec 7.3b/p 115
		2) Transco is not obligated to deliver below 20% balance in Storage Capacity Quantity from Nov 1 thru Feb 14									sec 7.3c/p 115
		3) Transco is not obligated to deliver below 7% balance in Storage Capacity Quantity from Feb 15 thru Mar 1									sec 7.3c/p 115
	Seasonal Rules	1) Minimum turnover is the difference between 35% of storage capacity and prior November 1 balance by Apr 15 (Does not include injection during winter period)									sec 7.3d/p 116
		2) Minimum inventory levels = Dec, Jan, 35%; Feb 15%; if not then obligation of storage demand will be reduced 5%									sec 7.3e/p 116
		3) Minimum turnover - By Apr 1, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									
		4) Subject to specific buyer OFO's to allow Transco manage GSS									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	SS-2	2,846,250	18,975	0 -10% of Storage Cap Quantity =1/150	4/1-10/31	25,875	77	>30 -100% of Annual Storage Volume in balance =1/110	110	11/1-3/31	
	1004032		17,789	>10-30% of Storage Cap Quantity =1/160		23,719	18	>15 -30% of Annual Storage Volume in balance =1/120			
			16,264	>30-50% of Storage Cap Quantity =1/175		21,083	7	>10 -15% of Annual Storage Volume in balance =1/135			
			15,385	>50-70% of Storage Cap Quantity =1/185		18,975	15	<10% of Annual Storage Volume in balance =1/150			
			14,231	>70-100% of Storage Cap Quantity =1/200		Total	117				
	INJ RULES:										GT&C sec.18.1
	WDL RULES:	1) Swing rate ability, subject to Sec. 18.1 of GT&C									GT&C sec.18.1
	Seasonal Rules	1) Swing rate ability, subject to Sec. 18.1 of GT&C									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON	Tariff Reference
TRANSCO	LSS	827,053	4,595	0 -50% of Storage Cap Quantity =1/180	4/1-10/31	7518	71	MDWQ =100% if % if gas in storage is >35%	110	11/1-3/31	sec 5.1/p 249C
	1000796		3,865	50-100% of Storage Cap Quantity =1/214		7,142	5	95% of MDWQ if % if gas in storage is >=30% and < 35%			
						5,639	21	75% of MDWQ if % if gas in storage is >=16% < 30%			
						5,037	10	67% of MDWQ if % if gas in storage is >=10% and < 16%			
						3,759	22	50% of MDWQ if % if gas in storage is >0% and < 10%			
						Total	129				
	INJ RULES:										sec 5.1/p 249C
	WDL RULES:	1) Transco is required to deliver only 92% in any consecutive 30 day period									sec 5.1/p 249C
	Seasonal Rules	1) Seasonal withdrawals must be Nov 1 balance by March 31									
		2) Minimum inventory levels = Dec, Jan, 35%; Feb 15%; if not then obligation of storage demand will be reduced 6.67%									
		1) Minimum turnover is the difference between 35% of storage capacity and prior November 1 balance by Apr 1									
		3) Minimum turnover - By Apr 1, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									
		4) Subject to specific buyer OFO's to allow Transco manage LSS									

PIPELINE	PIPELINE RATE	SEASONAL CAPACITY (net)	INJECTION Dth/ D	INJECTION MISC	INJECT SEASON	WITHDRAWAL Dth/D	WITHDRAWAL Operational # of Days	WITHDRAWAL RATCHETS	Contractual Number of Days	W/D SEASON
TRANSCO	ESS	83,847	838		YEAR	10,000	9		9	YEAR
	1006655				ROUND					ROUND
	INJ RULES:	Subject to Transco's operating conditions in the Eminence field and system conditions at the time								
	WDL RULES:	Subject to Transco's operating conditions in the Eminence field and system conditions at the time								
	Seasonal Rules									

	PIPELINE	SEASONAL	INJECTION		INJECT	WITHDRAWAL			Contractual	W/D	Tariff
	PIPELINE	SEASONAL	INJECTION		INJECT	WITHDRAWAL			Contractual	W/D	Tariff
PIPELINE	RATE	CAPACITY (net	Dth/ D	MISC	SEASON	Dth/D	Operational # of Days	RATCHETS	Number of Days	SEASON	Reference
DOMINION	**GSS**	200,000	1,111	SUMMER : if storage balance < or = 1/2	YEAR	**2,000**	**65**	100% MDWQ if % if gas in storage is >35%	100	YEAR	
	300109		935	of capacity then 1/180 of capacity;	ROUND	**1,840**	**21**	92% MDWQ if % if gas in storage is <35% and >16%		ROUND	
				if storage balance > or = 1/2 of capacity		**1,400**	**9**	70% MDWQ if % if gas in storage is <16% and >10%			
				then 1/214 of capacity		**1,260**	**16**	63% MDWQ if % if gas in storage is <10% and >0%			
				WINTER : 1/214 of capacity							
	INJ RULES:	1) Tariff injection tolerance = 115% of MDIQ Apr 1 thru Jul 31;									
		= 107% in Aug; 102% in Sept and Oct									
		2) Excess injections may be requested, subject to excess charge									rate sheet 35
	WDL RULES:	1) Monthly limit : Dominion is required to deliver only 87.5% in any month									sec. 8.6/p.358
		2) Excess withdrawals may be requested, subject to excess charge									sht 35/sec. 9.1
	Seasonal Rules	1) Minimum turnover - By Apr 15, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									sec. 8.7/p.358
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		2) Monthly minimum balances: Dec and Jan=35%; Feb=15%. Failure to maintain minimum levels will reduce withdrawal by 10%									sec. 8.5/p.358
	Overrun	1) Daily Injection Overruns - if uncorrected over tolerance then subject to Unauthorized Overrun Charge									rate sheet 39
		2) Storage Capacity Overruns - if not adjusted within 24hrs, then subject to Storage Gas Balance Unauthorized Overrun Charge									rate sheet 39
		3) Daily Withdrawal Overruns - if uncorrected over entitlement then subject to Unauthorized Withdrawal Overrun Charge									rate sheet 39
		4) Daily Withdrawal Overruns - if withdrawals exceed storage gas balance, then subject to $25/dth per day until gas is replaced									
		5) Failure to comply with Minimum Turnover, then subject to a charge of 2 times the effective fuel retention % by deducting the dth from the gas balance.									

	PIPELINE	SEASONAL	INJECTION		INJECT	WITHDRAWAL			Contractual	W/D	Tariff
PIPELINE	RATE	CAPACITY (net	Dth/ D	MISC	SEASON	Dth/D	Operational # of Days	RATCHETS	Number of Days	SEASON	Reference
DOMINION	**GSS**	200,000	1,111	SUMMER : if storage balance < or = 1/2	YEAR	**2,000**	**65**	100% MDWQ if % if gas in storage is >35%	100	YEAR	
	300110		935	of capacity then 1/180 of capacity;	ROUND	**1,840**	**21**	92% MDWQ if % if gas in storage is <35% and >16%		ROUND	
				if storage balance > or = 1/2 of capacity		**1,400**	**9**	70% MDWQ if % if gas in storage is <16% and >10%			
				then 1/214 of capacity		**1,260**	**16**	63% MDWQ if % if gas in storage is <10% and >0%			
				WINTER : 1/214 of capacity							
	INJ RULES:	1) Tariff injection tolerance = 115% of MDIQ Apr 1 thru Jul 31;									
		= 107% in Aug; 102% in Sept and Oct									
		2) Excess injections may be requested, subject to excess charge									rate sheet 35
	WDL RULES:	1) Monthly limit : Dominion is required to deliver only 87.5% in any month									sec. 8.6/p.358
		2) Excess withdrawals may be requested, subject to excess charge									sht 35/sec. 9.1
	Seasonal Rules	1) Minimum turnover - By Apr 15, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									sec. 8.7/p.358
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		2) Monthly minimum balances: Dec and Jan=35%; Feb=15%. Failure to maintain minimum levels will reduce withdrawal by 10%									sec. 8.5/p.358
	Overrun	1) Daily Injection Overruns - if uncorrected over tolerance then subject to Unauthorized Overrun Charge									rate sheet 39
		2) Storage Capacity Overruns - if not adjusted within 24hrs, then subject to Storage Gas Balance Unauthorized Overrun Charge									rate sheet 39
		3) Daily Withdrawal Overruns - if uncorrected over entitlement then subject to Unauthorized Withdrawal Overrun Charge									rate sheet 39
		4) Daily Withdrawal Overruns - if withdrawals exceed storage gas balance, then subject to $25/dth per day until gas is replaced									
		5) Failure to comply with Minimum Turnover, then subject to a charge of 2 times the effective fuel retention % by deducting the dth from the gas balance.									

	PIPELINE	SEASONAL	INJECTION		INJECT	WITHDRAWAL			Contractual	W/D	Tariff
PIPELINE	RATE	CAPACITY (net)	Dth/ D	MISC	SEASON	Dth/D	Operational # of Days	RATCHETS	Number of Days	SEASON	Reference
TETCO	**SS-1**	541,911	2,785		YEAR	**7,659**	**48**	> 174,300 but <= 541,911	71	YEAR	
	400190				ROUND	**6,762**	**7**	> 125,601 but <= 174300		ROUND	
						5,707	**9**	> 73,101 but <=125,600			
						1,516	**27**	>32,601 but <= 73,100			
						929	**35**	<= 32,600			
	INJ RULES:	1) Excess injections may be requested, subject to charge									
	WDL RULES:	1) Excess withdraws may be requested, subject to charge									
	Seasonal Rules	1) No-notice service that cannot exceed MSQ; No carryover provisions									
		2) If, at any time the MSQ is <10% of aggregate customers MSQ, then for remaining year any injs or transfers will not be included in determining the ratchet									
	Overrun	1) MONTHLY PENALTIES :Charge for excess injections/withdrawals is maximum (p.52 of tariff) times dth in excess									sec. 6.3
		2) Subject to cashout									

	PIPELINE	SEASONAL	INJECTION		INJECT	WITHDRAWAL			Contractual	W/D	Tariff
PIPELINE	RATE	CAPACITY (net)	Dth/ D	MISC	SEASON	Dth/D	Operational # of Days	RATCHETS	Number of Days	SEASON	Reference
TRANSCO	**GSS**	57,881	322	0 -50% of Storage Cap Quantity =1/180	YEAR	**1,102**	**34**	MDWQ =100% if % if gas in storage is >35%	59	YEAR	sec. 7.3a
	1000780		270	50-100% of Storage Cap Quantity =1/214	ROUND	**1,091**	**8**	99% of MDWQ if % if gas in storage is 20% to 35%		ROUND	
						815	**9**	74% of MDWQ if % if gas in storage is 7% to 20%			
						606	**7**	55% of MDWQ if % if gas in storage is 0% to7 %			
	INJ RULES:	1) Swing rate schedule									
	WDL RULES:	1) Transco is required to deliver only 87.5% in any consecutive 30 day period									sec 7.3b/p 115
		2) Transco is not obligated to deliver below 20% balance in Storage Capacity Quantity from Nov 1 thru Feb 14									sec 7.3c/p 115
		3) Transco is not obligated to deliver below 7% balance in Storage Capacity Quantity from Feb 15 thru Mar 1									sec 7.3c/p 115
	Seasonal Rules	1) Seasonal withdrawals must be Nov 1 balance by Apr 15									sec 7.3d/p 116
		2) Minimum inventory levels = Dec, Jan, 35%; Feb 15%; if not then obligation of storage demand will be reduced 5%									sec 7.3e/p 116
		Season Withdrawal Obligation = (Starting Nov 1 Storage Balance) - (0.35 x Seasonal Capacity Quantity)									
		3) Minimum turnover - By Apr 1, total withdrawals must be equal to or greater than the Nov 1 balance of preceding year									
		4) Subject to specific buyer OFO's to allow Transco manage GSS									

	PIPELINE	SEASONAL	INJECTION		INJECT	WITHDRAWAL			Contractual	W/D	Tariff
PIPELINE	RATE	CAPACITY (net)	Dth/ D	MISC	SEASON	Dth/D	Operational # of Days	RATCHETS	Number of Days	SEASON	Reference
TRANSCO	**LGA**	4,140	21	Returns = 1/200 of Liquefaction	4/1-10/31	**1,035**	**4**	NOT RATCHETED	4	11/1-3/31	sec. 7.3a
	1000783			Capacity Quantity]							
	INJ RULES:	1) Injections during withdrawal period may be requested									
	WDL RULES:	1) Swing rate ability, subject to Sec. 18.1 of GT&C									sec 7.3b/p 115
		2) Excess withdrawals may be requested, subject to excess delivery charge (rate sheet 27)									sec 7.3c/p 115
		3) Withdrawals during Nov and Apr may be requested									sec 7.3c/p 115
	Seasonal Rules	1) Cumulative delivery nominations during withdrawal period will not exceed beginning Gas Balance									sec 7.3d/p 116
											sec 7.3e/p 116

	PIPELINE	SEASONAL	INJECTION		INJECT	WITHDRAWAL			Contractual	W/D	Tariff
PIPELINE	RATE	CAPACITY (net	Dth/ D	MISC	SEASON	Dth/D	Operational # of Days	RATCHETS (Based on Top Inventory)	Number of Days	SEASON	Reference
UGI STORAGE Co.	**FSS**	879,200	4,885	0 -50% of Storage Cap Quantity	YEAR	**8,792**	**75**	100% MDWQ if % if gas in storage is >25%	100	YEAR	sec 6.0.2.1
			4,103	50-100% of Storage Cap Quantity - 84% of MDIQ	ROUND	**4,396**	**50**	50% MDWQ if % if Inventory is < 25%		ROUND	sec 9.2

SDR-COS-15

Request:

For the most recent annual period available, please identify the applicable monthly volumes and revenues under each rate schedule which were:

a. Sold under a negotiated or market-based rate

b. Transported under a negotiated or market based rate

c. Transported at full margin transportation rates

Response:

Please see Attachment SDR-COS-15.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Sales and Revenues for Selected Rate Schedules

a.	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21
Sales (Mcf)												
None	-	-	-	-	-	-	-	-	-	-	-	-
Revenue ($)												
None	-	-	-	-	-	-	-	-	-	-	-	-
b.												
Sales (Mcf)												
Rate IS	1,252,959	1,276,615	1,418,559	1,387,376	1,232,337	1,259,630	1,156,622	1,072,136	990,706	999,831	958,785	1,024,126
Rate XD	15,933,792	13,826,279	17,276,341	16,497,667	15,360,567	14,955,007	12,958,666	13,597,570	15,864,268	18,027,536	18,141,314	14,322,345
Revenue ($)												
Rate IS	$ 2,146,511	$ 2,063,269	$ 2,449,219	$ 2,395,487	$ 2,279,203	$ 2,126,287	$ 1,771,160	$ 1,519,711	$ 1,443,843	$ 1,535,340	$ 1,647,415	$ 1,461,138
Rate XD	$ 2,739,106	$ 2,723,767	$ 3,112,792	$ 2,883,624	$ 2,978,879	$ 2,738,746	$ 2,734,835	$ 2,777,692	$ 2,760,145	$ 3,124,404	$ 2,535,362	$ 2,861,127
c.												
Sales (Mcf)												
Rate RT	281,495	675,580	1,005,334	1,243,990	1,178,717	767,294	428,099	227,423	115,799	111,218	109,260	104,079
Rate NT	642,623	1,221,772	1,775,026	2,253,205	2,125,253	1,449,427	915,781	581,099	353,628	381,553	405,846	408,677
Rate DS	667,417	832,311	1,355,267	1,498,429	1,365,526	1,063,959	645,876	421,522	278,965	273,711	265,611	314,042
Rate LFD	1,684,588	1,874,066	2,340,569	2,574,085	2,410,610	2,252,672	1,863,697	1,636,038	1,469,480	1,407,873	1,483,329	1,519,181
Revenue ($)												
Rate RT	$ 2,375,752	$ 4,071,574	$ 5,437,286	$ 6,698,616	$ 6,383,281	$ 4,719,373	$ 3,075,632	$ 2,271,429	$ 1,662,901	$ 1,681,698	$ 1,752,760	$ 1,618,290
Rate NT	$ 2,736,694	$ 4,643,249	$ 6,632,418	$ 8,335,751	$ 7,914,184	$ 5,625,170	$ 3,695,517	$ 2,539,060	$ 1,690,623	$ 1,839,782	$ 1,969,472	$ 1,919,418
Rate DS	$ 3,998,861	$ 4,022,313	$ 5,543,434	$ 5,987,939	$ 5,669,748	$ 4,731,745	$ 3,606,900	$ 2,894,515	$ 2,525,490	$ 2,609,316	$ 2,498,154	$ 2,661,930
Rate LFD	$ 3,371,119	$ 3,530,078	$ 4,327,078	$ 4,630,207	$ 4,480,178	$ 4,287,075	$ 3,828,793	$ 3,126,187	$ 2,925,600	$ 2,748,169	$ 3,645,800	$ 3,032,990

SDR-COS-16

Request:

Please provide the following for each curtailment during the last three years:

a. Dates of curtailment

b. Type of curtailment (firm service, interruptible service, both)

c. Whether curtailment was related to amount of capacity on the Company's system, other capacity or supply related

d. Rate schedule that curtailed volumes would have been billed under

e. Curtailed volumes by rate schedule

f. Actual volumes moved by rate schedule

Response:

The Company has had no curtailments of firm service during the last three years.

Prepared by or under the supervision of: Christopher R. Brown

SDR-COS-17

Request:

Please identify the Company's design day planning criteria and the probability of design day occurrence. Include any available documentation supporting the Company's claimed probability of occurrence.

Response:

Please see Book I, Section 11 of the 2021 1307(f) Purchased Gas Cost filing for UGI Gas at Docket No. R-2021-3025652 which can be found at https://www.puc.pa.gov/pcdocs/1702100.pdf.

Prepared by or under the supervision of: Christopher R. Brown

SDR-COS-18

Request:

For each customer class contained in the cost of service study, please provide monthly throughput by class.

Response:

Please see Attachment SDR-COS-18.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Sales by Cost of Service Study Classsification (Mcf's)

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL 2023
Service Classification:													
Rate R/RT	3,010,682	5,967,341	8,237,853	10,433,342	8,451,162	6,991,839	3,637,535	1,626,797	912,453	726,294	783,662	1,228,023	52,006,983
Rate N/NT	1,834,920	3,484,738	4,775,749	6,038,952	4,889,686	4,053,271	2,172,444	1,076,968	695,628	597,060	627,373	862,831	31,109,619
Rate DS	512,490	856,032	1,329,724	1,697,064	1,550,482	1,272,062	737,613	442,067	320,999	276,888	280,900	336,083	9,612,403
Rate LFD	1,825,652	2,157,211	2,472,502	2,745,207	2,453,300	2,262,269	1,900,119	1,689,885	1,536,918	1,485,599	1,526,832	1,583,829	23,639,324
Rate XD Firm	17,614,317	17,185,933	17,304,698	17,524,898	17,299,284	17,430,655	16,822,557	17,571,144	16,611,629	17,806,326	17,727,594	17,677,229	208,576,268
Rate Interruptible	1,222,541	1,340,461	1,460,678	1,572,531	1,479,968	1,453,605	1,338,735	1,186,047	1,102,552	1,101,082	1,086,738	1,107,042	15,451,980
Total	26,020,603	30,991,717	35,581,204	40,011,994	36,123,881	33,463,701	26,609,003	23,592,907	21,180,180	21,993,250	22,033,100	22,795,036	340,396,577

SDR-COS-19

Request:

Please provide workpapers showing the development of each allocation factor reflected in the Company's cost of service study. Include a description of each allocation factor, all calculations performed to develop the allocators and all supporting documentation, studies or other information relied upon to determine the allocators.

Response:

Please refer to UGI Gas Exhibit D.

Prepared by or under the supervision of: Constance E. Heppenstall

SDR-COS-20

Request:

Please provide all workpapers, calculations and supporting documentation for the functionalization and classification performed for the Company's cost of service study.

Response:

Please refer to UGI Gas Exhibit D.

Prepared by or under the supervision of: Constance E. Heppenstall

SDR-COS-21

Request:

If not provided elsewhere, please provide a detailed proof of revenues at both present and proposed rates.

Response:

Please see UGI Gas Exhibit E - Proof of Revenue.

Prepared by or under the supervision of: Sherry A. Epler

SUPPLEMENTAL DATA REQUESTS – RATE OF RETURN

SDR-ROR-1

Request:

Please supply copies of the following documents for the Company and, if applicable, its parent:

a. Most recent Annual Report to shareholders (including any statistical supplements);

b. Most recent SEC Form l0K,

c. All SEC Form l0Q reports issued within last year.

Response:

a. Please refer to the UGI Corporation website for the most recent UGI Corporation Annual Report to shareholders at the following link: https://www.ugicorp.com/investors/financial-reports/annual-reports.

b. Please refer to the response to request II-A-3 for the UGI Corporation SEC Form 10-K.

c. Please refer to the SEC website for copies of all SEC Form 10Q reports for UGI Corporation issued within the last year. These can be found at:

- Quarter ended December 31, 2020:
https://www.sec.gov/ix?doc=/Archives/edgar/data/0000884614/000088461421000011/ugi-20201231.htm

- Quarter ended March 31, 2021:
https://www.sec.gov/ix?doc=/Archives/edgar/data/0000884614/000088461421000026/ugi-20210331.htm

- Quarter ended June 30, 2021:
https://www.sec.gov/ix?doc=/Archives/edgar/data/0000884614/000088461421000048/ugi-20210630.htm

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-2

Request:

Please supply copies of the Company's balance sheets for each month/quarter for the last two years.

Response:

Please see Attachment SDR-ROR-2.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Quarterly Balance Sheets
($ In Thousands)

Quarter End Date	Dec 31, 2019	Mar 31, 2020	Jun 30, 2020	Sep 30, 2020	Dec 31, 2020	Mar 31, 2021	Jun 30, 2021	Sep 30, 2021
Utility Plant	$ 2,917,930	$ 2,968,393	$ 3,004,513	$ 3,064,429	$ 3,113,814	$ 3,145,453	$ 3,229,737	$ 3,320,845
Other Investments	1,393	1,393	1,393	1,393	1,393	1,393	1,393	1,393
Cash and Cash Equivalents	7,531	754	4,097	4,634	9,025	5,873	1,419	1,033
Accounts Receivable	216,507	245,812	193,692	172,900	221,784	255,289	203,314	176,968
Other Receivables	75,986	36,132	10,926	11,781	57,224	29,625	4,077	5,501
Other Assets	710,481	684,346	694,249	701,944	704,765	685,809	689,980	673,593
Total Assets	$ 3,929,827	$ 3,936,829	$ 3,908,869	$ 3,957,080	$ 4,108,004	$ 4,123,442	$ 4,129,919	$ 4,179,333
Current and Accrued Liabilities	$ 547,600	$ 495,750	$ 316,362	$ 442,388	$ 572,414	$ 502,755	$ 407,972	$ 429,789
Other Non-current Liabilities	195,360	194,190	199,591	213,004	207,176	201,288	192,824	130,793
Long-term Debt	918,317	916,840	1,057,187	1,055,710	1,054,233	1,052,755	1,145,828	1,215,263
Other Deferred Liabilities	1,059,331	1,067,251	1,084,229	1,066,449	1,068,664	1,068,436	1,084,346	1,124,405
Total Liabilities	2,720,607	2,674,030	2,657,369	2,777,551	2,902,487	2,825,234	2,830,970	2,900,251
Equity	1,209,220	1,262,799	1,251,500	1,179,529	1,205,516	1,298,208	1,298,949	1,279,083
Total Liabilities and Equity	$ 3,929,827	$ 3,936,829	$ 3,908,869	$ 3,957,080	$ 4,108,004	$ 4,123,442	$ 4,129,919	$ 4,179,333

SDR-ROR-3

Request:

Please provide the bond rating history for the Company and, if applicable, its parent from the major credit rating agencies for the last five years.

Response:

Please see Attachment SDR-ROR-3.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Bond Rating History

	Fiscal Period End				
UGI Corporation	2017	2018	2019	2020	2021
Egan Jones					
Local Currency (LC) Senior Unsecured	BBB+	BBB+	BBB+	BB+	BBB-
Foreign Currency (FC) Senior Unsecured	BBB+	BBB+	BBB+	BB+	BBB-
Local Currency Commercial Paper	A1	A1	A1	A2	A1
Foreign Currency Commercial Paper	A1	A1	A1	A2	A1

	Fiscal Period End				
UGI Utilities, Inc.	2017	2018	2019	2020	2021
Fitch					
LT Issuer Default Rating	A-	A-	A-	A-	A-
Senior Unsecured Debt	A	A	A	A	A
*S&P					
LT Local Issuer Credit					
LT Foreign Issuer Credit					
Moody's					
Senior Unsecured Debt	A2	A2	A2	A2	A2
Long Term Rating	A2	A2	A2	A2	A2

***S&P Does not publish a rating on UGI Utilities, Inc Debt**

SDR-ROR-4

Request:

Please provide copies of all bond rating reports relating to the Company and, if applicable, its parent for the past two years.

Response:

Please see the following attachments for the bond rating reports for UGI Utilities, Inc. located on the USB flash drive:

Attachment SDR-ROR-4.1 for Fitch Credit Opinion dated March 8, 2021

Attachment SDR-ROR-4.2 for Fitch Credit Opinion dated March 9, 2020

Attachment SDR-ROR-4.3 for Moody's announcement of periodic review dated September 20, 2021

Attachment SDR-ROR-4.4 for Moody's rating action dated November 16, 2021

Attachment SDR-ROR-4.5 for Moody's announcement of periodic review dated October 7, 2020

The Moody's Credit Opinions dated November 29, 2021 and November 24, 2020 are confidential and will be provided to those parties who execute the appropriate Protective Order.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-5

Request:

Please provide a work paper showing the derivation of the Company's current AFUDC rate.

Response:

Please see the response to II-A-11.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-6

Request:

Please supply copies of all presentations by the Company's and, if applicable, its parent's management to securities analysts during the past 2 years. This would include presentations of financial projections.

Response:

Copies of securities analysts presentations for 2020 and 2021 can be found at https://www.ugicorp.com/investors/financial-reports/events-and-presentations.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-7

Request:

Please provide a listing of all securities issuances for the Company and, if applicable, its parent projected for the next two years. The response should identify for each projected issuance the date, dollar amount, type of security, and effective cost rate.

Response:

UGI Utilities does not have publicly traded stock. UGI Corp ("the Company"), the parent company of UGI Utilities, does have publicly traded stock.

On May 25, 2021, the Company issued 2.2 million Equity Units with a total notional value of $220 million. Each Equity Unit has a stated amount of $100 and consists of (i) a 10% undivided beneficial ownership interest in one share of Convertible Preferred Stock with a liquidation preference of $1,000 per share and (ii) a 2024 Purchase Contract. The Company received approximately $213 million of proceeds from the issuance of the Equity Units, net of offering expenses and underwriting costs and commissions, and issued 220,000 shares of Convertible Preferred Stock, recording $213 million in "Preferred stock" on UGI Corporation's Consolidated Balance Sheet. The proceeds were used to pay a portion of the purchase price for the Mountaineer Acquisition and related fees and expenses, and for general corporate purposes.

Please see the Direct Testimony of Paul R. Moul, UGI Gas Statement No. 6, for discussion of expected debt issuances for UGI Utilities.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-ROR-8

Request:

Please identify all of the Company's and, if applicable, its parent's publicly underwritten common stock issuances written in the last five years. Identify which such issuances were related to mergers or acquisitions, and which were undertaken to fund facility investments in utility plant and equipment.

Response:

The Company has not issued stock in the last five years.

The Parent has not issued any stock to fund facility investments in utility plant and equipment in the last five years. The Parent has issued stock related to the below transaction which was considered a merger. The below is an excerpt from the UGI Corporation ("UGI") 10-K filed 11/26/2019. The Common Units discussed in this excerpt represent AmeriGas partnership units.

"On August 21, 2019, the AmeriGas Merger was completed in accordance with the terms of the Merger Agreement entered into on April 1, 2019. Under the terms of the Merger Agreement, the Partnership was merged with and into Merger Sub, with the Partnership surviving as an indirect wholly owned subsidiary of UGI. Each outstanding Common Unit other than the Common Units owned by UGI was automatically converted at the effective time of the AmeriGas Merger into the right to receive, at the election of each holder of such Common Units, one of the following forms of merger consideration (subject to proration designed to ensure the number of shares of UGI Common Stock issued would equal approximately 34.6 million):

(i) 0.6378 shares of UGI Common Stock (the "Share Multiplier");

(ii) $7.63 in cash, without interest, and 0.500 shares of UGI Common Stock; or

(iii) $35.325 in cash, without interest.

Pursuant to the terms of the Merger Agreement, effective on August 21, 2019, we issued 34,612,847 shares of UGI Common Stock and paid $528.9 million in cash to the holders of Common Units other than UGI, for a total implied consideration of $2,227.7 million. In addition, the incentive distribution rights in the Partnership previously owned by the

SDR-ROR-8 (Continued)

General Partner were canceled. After-tax transaction costs directly attributable to the transaction that were incurred by UGI totaling $7.7 million were recorded as a reduction to UGI stockholders' equity. Transaction costs incurred by the Partnership totaling $6.3 million are reflected in "Operating and administrative expenses" on the 2019 Consolidated Statement of Income. The tax effects of the AmeriGas Merger resulting from the step-up in tax bases of the underlying assets resulted in the recording of a deferred tax asset in the amount of $512.3 million. This deferred tax asset is included in "Deferred income taxes" on the September 30, 2019 Consolidated Balance Sheet.

Effective upon completion of the AmeriGas Merger, Common Units are no longer publicly traded."

On May 25, 2021, the Company's parent issued 2.2 million Equity Units with a total notional value of $220 million. The Equity Units are equity-linked securities and not common stock. Therefore, the Company has determined not to include the Equity Units in the answer to this request.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-9

Request:

Please identify any plan by the Company to refinance high cost long-term debt or preferred stock.

Response:

Please see the Direct Testimony of Paul R. Moul, UGI Gas Statement No. 6, for discussion of expected long-term debt issuances from UGI Utilities.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-ROR-10

Request:

Please provide copies of all securities analysts' reports relating to the Company and/or its parent issued within the past 2 years.

Response:

Please see the following Janney analyst reports on UGI Corporation issued in 2020 and 2021. The attachments are located on the USB flash drive:

Attachment SDR-ROR-10.1 – Janney report dated December 8, 2020
Attachment SDR-ROR-10.2 – Janney report dated June 30, 2020
Attachment SDR-ROR-10.3 – Janney report dated January 25, 2021
Attachment SDR-ROR-10.4 – Janney report dated February 4, 2021
Attachment SDR-ROR-10.5 – Janney report dated May 7, 2020
Attachment SDR-ROR-10.6 – Janney report dated November 19, 2020
Attachment SDR-ROR-10.7 – Janney report dated January 5, 2021
Attachment SDR-ROR-10.8 – Janney report dated June 22, 2021
Attachment SDR-ROR-10.9 – Janney report dated May 7, 2021
Attachment SDR-ROR-10.10 – Janney report dated October 13, 2021
Attachment SDR-ROR-10.11 – Janney report dated November 19, 2021
Attachment SDR-ROR-10.12 – Janney report dated December 3, 2021

All other securities analysts' reports relating to the Company and/or its parent issued in the last two years are confidential and will be provided to those parties who execute the appropriate Protective Order.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-11

Request:

If applicable, please supply a listing of all common equity infusions from the parent to the Company over the past five years. In each case, identify date and dollar amount.

Response:

There have been no common equity infusions from UGI Corporation to UGI Utilities, Inc. over the past five years.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-12

Request:

If applicable, please identify the Company's common dividend payments to its parent for each of the last five years.

Response:

The following schedule represents common dividend payments from UGI Utilities, Inc. to UGI Corporation for each of the last five fiscal years:

	(000's)
2017	$57,700
2018	$50,000
2019	$20,000
2020	$50,000
2021	$35,000

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-13

Request:

Please provide the latest year-by-year financial projections for the Company for the next five years. Also, please indicate the date these projections were prepared; whether approved by management; and whether the projections have been submitted to bond rating agencies.

(Information should be treated in a confidential manner.)

Response:

UGI Gas prepares an annual Budget and three-year Plan. The Budget and Plan were approved in September 2021. These projections will be included in consolidated UGI Utilities, Inc. financial projections to be presented to bond rating agencies.

Please refer to the response to II-A-13 for a schedule of financial projections for Fiscal Years 2022 and 2023.

The projections for Fiscal Years 2024 and 2025 are confidential and will be made available to parties upon request and the entry of an acceptable Protective Order.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-ROR-14

Request:

Please provide the Company's five-year construction budget.

Response:

The Company prepares a budget for the upcoming fiscal year and a plan for the three future years. The actual capital spending for the Fiscal Years ended September 30, 2020 and September 30, 2021 as well as the projected capital spending for the Fiscal Years ending September 30, 2022 and September 30, 2023 are provided on Attachment SDR-ROR-14.

The projection for Fiscal Year 2024 is confidential and will be made available to parties upon request and upon the entry of an acceptable Protective Order.

Prepared by or under the supervision of: Vicky A. Schappell

UGI Utilities, Inc. - Gas Division
Capital Spending by Budget Group
For the Years Ending September 30, 2020 through September 30, 2023

Group	FY2020	FY2021	FY2022	FY2023
01O - Misc-Plant Equipment	$ 2,187,210	$ 233,928	$ 178,275	$ -
01R - Remediation	(135,741)	810	-	-
02O - Building/Building Improvements/Land acquisition	19,288,312	23,623,600	16,356,064	18,263,553
03O - Furniture and Office Equipment	809,286	312,905	350,000	350,000
04O - Fleet Capital and Related Equipment	8,561,236	8,752,110	9,267,709	9,394,275
07O - Operations Tool Blanket	3,274,132	5,580,080	3,409,968	3,366,726
09O - Regulator Station Enhancements/Replacements	17,869,235	21,147,677	33,449,438	34,221,057
11O - Corrosion Related Projects	4,451,602	3,656,295	5,236,953	4,786,833
12O - Distribution System Reliability Projects	15,207,706	15,054,009	28,116,842	17,380,133
13O - Gas Supply Projects	684,950	5,898,695	-	-
14S - IS Information Services	24,518,630	19,206,574	66,915,286	66,066,578
40G - New Business-Mains	16,057,369	29,994,292	17,789,673	15,450,179
40G1 - New Business-Mains GET Gas	11,728,053	8,882,793	10,261,897	7,822,140
41M - Main Replacement- Leaks	(3,354,969)	5,674,458	3,058,834	1,565,154
43M - Main Replacement- Relocation	13,821,223	14,465,292	17,544,777	15,767,476
44M - Main Replacement- Bare Steel	25,700,251	30,919,593	58,153,354	81,073,441
45M - Main Replacement- Cast Iron	69,148,648	83,552,901	88,741,947	101,373,365
49R - Cost of Removal-Mains	212,973	1,068,845	641,345	178,275
50G - New Business-Services	30,741,673	32,902,428	34,552,473	35,004,145
51G - New Business-Meters	3,376,277	3,180,600	3,812,157	3,658,779
51M - Replacement Meters/ERTs	8,566,837	4,528,064	5,643,684	5,114,803
51R - Cost of Removal-Meters	(68,699)	(54,540)	-	-
52G - New Business-Meter Installation	3,820,384	4,947,678	1,912,020	1,969,380
52M - Blanket Meter Installations	3,111,351	3,783,537	5,121,474	4,517,456
52R - Cost of Removal-Regulators	21,877	18,903	-	-
53M - Regulator Equipment	-	28,577	66,000	66,000
53M1 - Mercury Regulator Removal	295,709	64,126	300,000	300,000
54G - New Business-House Reg Install	(101,074)	-	-	-
54M - Maintenance-House Reg Install	343,785	25,699	250,000	250,000
55M - Meter Set Rebuild- Customer Specific	63,341	-	-	-
56R - Cost of Removal-Other	(322,386)	(247,318)	51,385	51,385
57G - New Business-Services GET Gas	680,920	614,137	1,646,527	1,695,918
58M - Replacement services not associated with main	42,712,524	41,321,596	35,816,092	36,300,723
59R - Cost of Removal-Services	4,919,930	4,339,576	3,851,862	3,851,862
60M - GA Transmission Replacement	(480,681)	11,675	-	-
93U - GA Undistributed Overhead-Growth	1,858,364	-	-	-
94U - GA Undistributed Overhead-Information Services	122,833	-	-	-
95U - GA Undistributed Overhead-Other	76,993	-	-	-
96U - GA Undistributed Overhead-Removal	67,631	-	-	-
97U - GA Undistributed Overhead-Replacement and Betterment	5,193,344	-	-	-
99U - GA Undistributed Overhead-Maintenance	1,009,259	(1,022,060)	-	-
94G - New Business-M & R Station Equipment	272,036	1,598,327	-	-
Total	$ 336,312,334	$ 374,065,859	$ 452,496,038	$ 469,839,637

SDR-ROR-15

Request:

Please identify the Company's and, if applicable, its parent's capital structure targets (percentages of capital types). Provide the complete basis for the capital structure targets.

Response:

Please see the Direct Testimony of Paul R. Moul, UGI Gas Statement No. 6, and UGI Gas Exhibit B for capital structure targets.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-ROR-16

Request:

For each month, of the most recent 24 months, please supply the Company's

a. short-term debt balance;

b. short-term debt interest rate;

c. balance of construction work in progress; and

d. balance of construction work in progress which is eligible for AFUDC accrual.

Response:

Please refer to Attachment SDR-ROR-16 for the requested information.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
SHORT TERM DEBT BALANCE AND CWIP BALANCE
FOR THE PERIOD OF OCTOBER 2019 THROUGH SEPTEMBER 2021

Year	Month	Short Term Debt Balance (000's)	Short Term Debt Interest Rate	Construction Work in Progress Balance (000's)	CWIP Eligible for AFUDC Balance (000's)
2019	October	$ 187,209	2.8637%	$ 79,720	$ 54,800
2019	November	$ 224,556	2.6368%	$ 86,452	$ 59,427
2019	December	$ 263,795	2.6237%	$ 86,166	$ 59,231
2020	January	$ 249,139	2.5929%	$ 84,839	$ 58,318
2020	February	$ 222,193	2.5268%	$ 85,326	$ 58,653
2020	March	$ 211,792	2.0136%	$ 103,111	$ 70,879
2020	April	$ 179,645	1.8132%	$ 93,665	$ 64,385
2020	May	$ 127,643	1.1922%	$ 102,144	$ 70,214
2020	June	$ 37,820	1.0606%	$ 126,053	$ 86,649
2020	July	$ 53,894	1.1505%	$ 124,075	$ 85,289
2020	August	$ 84,150	1.0993%	$ 105,240	$ 72,342
2020	September	$ 133,316	1.0360%	$ 90,514	$ 62,219
2020	October	$ 160,735	1.0880%	$ 76,272	$ 52,429
2020	November	$ 241,103	1.0850%	$ 76,530	$ 52,607
2020	December	$ 251,503	1.0379%	$ 75,541	$ 51,927
2021	January	$ 254,340	1.0132%	$ 82,351	$ 56,608
2021	February	$ 222,193	0.9978%	$ 87,280	$ 59,996
2021	March	$ 182,482	0.9871%	$ 95,485	$ 65,636
2021	April	$ 164,517	0.9895%	$ 96,702	$ 66,473
2021	May	$ 167,354	0.9880%	$ 94,220	$ 64,767
2021	June	$ 94,550	0.9907%	$ 108,679	$ 74,706
2021	July	$ 120,079	0.9755%	$ 83,707	$ 57,540
2021	August	$ 147,498	0.9667%	$ 101,937	$ 70,071
2021	September	$ 122,915	0.9860%	$ 70,851	$ 48,703

SDR-ROR-17

Request:

If applicable, please provide the currently authorized returns on equity for each of the parent's utility subsidiaries of the same industry type as the Company. In each case identify the approximate date when the current return on equity was approved by the state commission.

Response:

UGI Utilities, Inc. – Gas Division's most recent base rate case filing was approved by the Pennsylvania Public Utility Commission on October 8, 2020, with no definitive return on equity. Mountaineer Gas Company's most recent base rate case was approved by the West Virginia Public Service Commission on December 26, 2019, with a 9.75% return on equity.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-18

Request:

Has the Utility reacquired or repurchased any debt within the last five years? If so, provide a summary of each gain or loss on reacquired debt, the date on which the utility commenced amortization of such a gain or loss, the regulatory commission decision addressing the treatment of such gain or loss on reacquired debt, if any, on interest expense.

Response:

UGI Gas has not reacquired or repurchased any debt within the last five years.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-19

Request:

Fully identify all debt (other than instruments traded in public markets) owed to all shareholders, corporate officers, or members of the board of directors, its affiliates, parent company, or subsidiaries.

Response:

UGI Gas does not owe any debt to shareholders, corporate officers, or members of the board of directors, its affiliates, parent company, or subsidiaries.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-20

Request:

Provide a summary statement of all stock dividends, splits, or par value changes during the two (2) year calendar period preceding the rate case filing.

Response:

UGI Utilities, Inc. does not have publicly traded common stock and has not issued stock as a dividend to UGI Corporation, its 100% common equity owner. There were no stock splits or par value changes in the previous two calendar years.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-ROR-21

Request:

If a claim of the filing utility is based on utilization of the capital structure or capital costs of the parent company and system--consolidated, the reasons for this claim must be fully stated and supported.

Response:

UGI Utilities, Inc. - Gas Division is not basing its filing on the parent company or system - consolidated capital structures or capital costs.

Prepared by or under the supervision of: Paul R. Moul

SDR-ROR-22

Request:

To the extent not provided in SDR III-A.13, supply projected capital requirements and sources of the filing utility, its parent and system-¬consolidated--for the test year and each of three (3) comparable future years.

Response:

Please refer to Attachment II-A-5 which discloses projected capital expenditures for Fiscal Years ending September 30, 2022, and September 30, 2023.

The projection for Fiscal Year 2024 is confidential and will be made available to parties upon request and the entry of an acceptable Protective Order.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-ROR-23

Request:

To the extent not provided elsewhere, supply financial data of Company and/or parent for the last five (5) years.

a. Times interest earned ratio — pre and post tax basis.

b. Preferred stock dividend coverage ratio — post tax basis.

c. Times fixed charges earned ratio — pre tax basis.

d. Dividend payout ratio.

e. AFUDC as a percent of earnings available for common equity.

f. Construction work in progress as a percent of net utility plant.

g. Effective income tax rate.

h. Internal cash generations as a percent of total capital requirements.

Response:

Please refer to Attachment SDR-ROR-23 for the requested information.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Select Financial Data for UGI Utilities, Inc. - Consolidated
For the Year Ended September 30,

	2017	2018	2019	2020	2021
a. Times Interest Earned Ratio - pre tax	5.68	5.54	4.55	4.20	4.42
Times Interest Earned Ratio - post tax	3.89	4.47	3.68	3.50	3.64
b. Preferred Stock Dividend Coverage ratio	N/A	N/A	N/A	N/A	N/A
c. Times Fixed Charges Earned Ratio	5.22	5.08	4.17	4.06	4.32
d. Dividend Payout Ratio	50%	34%	15%	37%	24%
e. AFUDC as a % of Net Utility Plant	0.083%	0.118%	0.144%	0.038%	0.013%
f. CWIP as a % of Net Utility Plant	4.95%	5.15%	2.73%	3.25%	2.46%
g. Effective Income Tax rate	38.31%	23.49%	24.38%	22.12%	22.83%
h. Internal Cash Generation as a % of Total Capital Requirements	76.6%	80.7%	69.6%	69.5%	76.5%

SUPPLEMENTAL DATA REQUESTS – REVENUE REQUIREMENTS

SDR-RR-1

Request:

Please provide a copy of the Company's detailed quarterly balance sheet and monthly income statements for the historic test year through the most recent month available.

Response:

Please see Attachment SDR-RR-1 for monthly income statements from October 2020 through November 2021. Please see Attachment SDR-ROR-2 for quarterly balance sheets.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Monthly Income Statements
(in thousands)

	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21
Revenues					
Gas Utility Revenues	$ 48,952	$ 80,964	$ 113,437	$ 136,800	$ 129,894
Other Operating Revenues	5,072	9,972	12,361	23,600	19,044
Total Operating Revenue	54,025	90,936	125,798	160,400	148,938
Expenses					
Operating Expense	3,211	3,074	3,127	2,778	3,164
Maintenance Expense	2,818	1,499	2,179	1,178	1,951
Customer Accounts Operations Expense	2,195	2,460	2,915	4,253	4,638
Customer Service and Information Operations Expense	(99)	93	83	75	104
Operation Sales Expense	71	213	122	73	225
Admin and General Operation Expense	7,740	8,247	11,015	13,864	7,483
Depreciation and Amortization Expense	8,800	8,789	8,953	9,090	9,028
Other taxes	429	693	923	1,163	1,017
Storage, Transportation and Other	18,700	39,982	54,763	76,943	68,412
Interest Income	93	64	44	55	44
Miscellaneous Income/Expense	86	421	1,035	(222)	(119)
Long Term Debt Interest	4,135	4,146	4,155	4,127	4,120
Other Interest Expense	196	245	299	254	204
Total Expenses before Taxes	48,373	69,925	89,614	113,631	100,272
Income Before Taxes	5,651	21,011	36,184	46,769	48,666
Tax Expense	1,283	4,669	8,249	10,940	11,410
Net Income	$ 4,369	$ 16,342	$ 27,935	$ 35,828	$ 37,256

UGI Utilities, Inc. - Gas Division
Monthly Income Statements
(in thousands)

	Mar-21	Apr-21	May-21	Jun-21	Jul-21
Revenues					
Gas Utility Revenues	$ 97,421	$ 63,227	$ 44,388	$ 31,358	$ 32,461
Other Operating Revenues	13,364	7,145	6,634	6,496	7,868
Total Operating Revenue	110,786	70,372	51,022	37,854	40,329
Expenses					
Operating Expense	4,243	3,139	3,447	3,727	3,082
Maintenance Expense	650	3,116	2,411	1,475	2,068
Customer Accounts Operations Expense	2,314	2,889	2,567	2,415	2,197
Customer Service and Information Operations Expense	148	90	92	86	75
Operation Sales Expense	(2)	148	148	167	146
Admin and General Operation Expense	9,899	9,334	8,561	7,961	8,903
Depreciation and Amortization Expense	9,052	9,080	9,248	9,175	9,218
Other taxes	1,028	883	746	(1,360)	1,016
Storage, Transportation and Other	47,774	26,681	17,657	12,181	14,319
Interest Income	68	97	105	45	40
Miscellaneous Income/Expense	(77)	(107)	(1)	(64)	133
Long Term Debt Interest	4,172	4,134	4,112	4,238	4,263
Other Interest Expense	208	221	(1,037)	200	301
Total Expenses before Taxes	79,479	59,707	48,057	40,245	45,759
Income Before Taxes	31,307	10,665	2,965	(2,391)	(5,430)
Tax Expense	6,482	2,390	646	(1,019)	(1,396)
Net Income	$ 24,825	$ 8,276	$ 2,318	$ (1,373)	$ (4,034)

UGI Utilities, Inc. - Gas Division
Monthly Income Statements
(in thousands)

	Aug-21	Sep-21	Oct-21	Nov-21
Revenues				
Gas Utility Revenues	$ 33,566	$ 32,027	$ 44,784	$ 105,636
Other Operating Revenues	7,028	8,508	9,684	16,940
Total Operating Revenue	40,594	40,535	54,468	122,576
Expenses				
Operating Expense	3,777	4,505	3,589	3,247
Maintenance Expense	2,758	341	2,278	2,506
Customer Accounts Operations Expense	3,011	2,810	2,172	2,880
Customer Service and Information Operations Expense	85	133	92	88
Operation Sales Expense	153	599	157	159
Admin and General Operation Expense	8,311	6,541	7,446	7,933
Depreciation and Amortization Expense	9,312	9,410	9,494	9,532
Other taxes	1,102	1,069	431	885
Storage, Transportation and Other	12,852	14,631	20,995	58,926
Interest Income	780	30	27	(88)
Miscellaneous Income/Expense	(90)	(154)	414	920
Long Term Debt Interest	4,284	4,319	4,351	4,383
Other Interest Expense	131	219	120	153
Total Expenses before Taxes	46,466	44,454	51,567	91,523
Income Before Taxes	(5,871)	(3,919)	2,901	31,053
Tax Expense	(1,077)	113	717	7,279
Net Income	$ (4,795)	$ (4,032)	$ 2,184	$ 23,774

SDR-RR-2

Request:

Please provide the actual number of customers by rate schedule as of December 31 for the last five years.

Response:

Please see Attachment SDR-RR-2.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Number of Customers Year End at December 31

Customer Class	2016	2017	2018	2019	2020
Rate R-Residential Non-Heating	31,228	29,318	27,368	26,124	25,676
Rate GL-Residential Gas Lights	57	53	47	44	38
Rate R-Residential Heat	485,678	478,103	477,539	485,948	495,951
Rate N-Commercial Non-Heating	3,465	3,373	3,338	3,355	3,309
Rate GL-Commercial Gas Lights	13	13	13	13	13
Rate N-Commercial Heat	44,985	44,861	44,671	45,633	46,452
Rate N-Industrial Non-Heating	119	117	112	111	107
Rate N-Industrial Heat	609	580	562	562	571
Rate RS-Retail and Standby	1	1	1	1	1
Sub-Total Retail	566,155	556,419	553,651	561,791	572,118
Rate RT- Residential Transportation	54,214	70,542	80,651	81,593	81,866
Rate NT-Non-Residential Transportation	16,105	17,305	18,559	18,604	18,744
Rate DS-Delivery Service	1,524	1,539	1,505	1,478	1,378
Rate XD-Extended Large Volume Delivery Service	103	109	109	109	109
Rate LFD-Large Firm Delivery Service	456	466	491	517	579
Rate IS-Interruptible Service - Transportation	330	321	312	306	300
Sub-Total Transportation	72,732	90,282	101,627	102,607	102,976
Grand Total	638,887	646,701	655,278	664,398	675,094

SDR-RR-3

Request:

Please provide the average number of customers by rate schedule for the last five years.

Response:

Please see Attachment SDR-RR-3.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Yearly Average Number of Customers for Period Ending September 30

Customer Class	2017	2018	2019	2020	2021
Rate R-Residential Non-Heating	30,406	28,087	26,576	25,645	24,929
Rate GL-Residential Gas Lights	56	51	45	43	38
Rate R-Residential Heat	483,578	475,189	478,486	486,630	497,429
Rate CIAC-Commercial and Industrial Air Conditioning	1	0	0	0	0
Rate N-Commercial Non-Heating	3,464	3,350	3,338	3,343	3,307
Rate GL-Commercial Gas Lights	13	13	13	13	13
Rate N-Commercial Heat	44,947	44,508	44,801	45,643	46,313
Rate N-Industrial Non-Heating	118	115	110	108	106
Rate N-Industrial Heat	604	575	561	563	588
Rate RS-Retail and Standby	1	1	1	1	1
Sub-Total Retail	563,188	551,889	553,931	561,989	572,724
Rate RT- Residential Transportation	55,499	73,142	79,605	82,538	80,074
Rate NT-Non-Residential Transportation	16,200	17,623	18,442	18,751	18,690
Rate DS-Delivery Service	1,524	1,505	1,497	1,425	1,374
Rate XD-Extended Large Volume Delivery Service	104	107	109	109	110
Rate LFD-Large Firm Delivery Service	457	472	495	546	581
Rate IS-Interruptible Service - Transportation	330	323	310	304	295
Sub-Total Transportation	74,114	93,172	100,458	103,673	101,124
Grand Total	637,302	645,061	654,389	665,662	673,848

SDR-RR-4

Request:

Please provide the actual number of customers by rate schedule at the end of each month from the commencement of the historic test year through the most recent month available and update as additional data become available.

Response:

Please see Attachment SDR-RR-4.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Number of Customers - Monthly

Customer Class	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21
Rate R-Residential Non-Heating	25,497	25,599	25,676	25,333	24,977	24,617	24,657	24,632	24,573	24,541	24,529	24,512
Rate GL-Residential Gas Lights	41	40	38	38	38	38	38	38	38	37	38	37
Rate R-Residential Heat	493,062	494,814	495,951	496,647	498,164	499,601	500,047	498,835	497,576	497,578	497,926	498,946
Rate N-Commercial Non-Heating	3,317	3,312	3,309	3,307	3,308	3,305	3,309	3,310	3,305	3,295	3,306	3,303
Rate GL-Commercial Gas Lights	13	13	13	13	13	13	13	13	13	13	13	13
Rate N-Commercial Heat	46,107	46,287	46,452	46,480	46,519	46,527	46,489	46,459	46,324	46,149	46,013	45,954
Rate N-Industrial Non-Heating	107	108	107	107	105	105	104	103	104	105	107	106
Rate N-Industrial Heat	572	570	571	587	588	599	596	595	588	591	593	601
Rate RS-Retail and Standby	1	1	1	1	1	1	1	1	1	1	1	1
Sub-Total Retail	568,717	570,744	572,118	572,513	573,713	574,806	575,254	573,986	572,522	572,310	572,526	573,473
Rate RT- Residential Transportation	81,214	81,557	81,866	82,509	81,929	81,220	80,279	79,465	78,471	77,889	77,344	77,145
Rate NT-Non-Residential Transportation	18,755	18,766	18,744	18,751	18,744	18,656	18,617	18,586	18,629	18,667	18,669	18,690
Rate DS-Delivery Service	1,385	1,371	1,378	1,375	1,379	1,371	1,372	1,372	1,371	1,371	1,374	1,367
Rate XD-Extended Large Volume Delivery Service	109	109	109	107	109	111	109	109	111	111	109	111
Rate LFD-Large Firm Delivery Service	572	576	579	581	578	577	581	583	584	585	587	589
Rate IS-Interruptible Service - Transportation	302	301	300	298	295	297	293	293	292	289	288	287
Sub-Total Transportation	102,337	102,680	102,976	103,621	103,034	102,232	101,251	100,408	99,458	98,912	98,371	98,189
Grand Total	671,054	673,424	675,094	676,134	676,747	677,038	676,505	674,394	671,980	671,222	670,897	671,662

SDR-RR-5

Request:

If past weather normalized sales or sales trends are used in models or otherwise relied on in reaching sales projections, please provide actual and normalized throughput by rate schedule as of December 31 for the last three years. Where applicable, separately identify sales and transportation throughput.

Response:

Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8, as well as the responses to SDR-RR-9, SDR-RR-10, and SDR-RR-11 for a description of the UGI Gas model used for forecasting sales for the Residential Heating ("RH") and Commercial Heating ("CH") rate groups, including supporting data.

Use per customer values for rate classes and class subgroups were established pursuant to the following:

The projected RH use per customer was established on a combined Rate R/RT - Heating total basis per the UGI Gas model detailed in Attachment SDR-RR-11(a). Weather normalized sales for Rate RT - Heating customers were then utilized to derive the separate Rate RT - Heating and Rate R - Heating use per customer values from the combined Rate R/RT - Heating value. Please see Attachment SDR-RR-5(a) for the actual and normalized sales utilized for Rate RT - Heating. Please see UGI Gas Exhibit SAE-7(a) for the derivation of the Rate R - Heating use per customer value.

Actual sales were normalized for combined Residential Non-Heating – Rate R and Rate RT in order to project combined use per customer in total. Please see Attachment SDR-RR-5(b) for the actual and normalized sales utilized for the combined Rate R/RT-Non-Heating value. Weather normalized sales for Non-Heating Rate RT were then utilized to derive the separate Rate RT and Rate R – Non-Heating customer values from the combined Rate R/RT – Non-Heating value. Please see Attachment SDR-RR-5(c) for the actual and normalized sales utilized for Rate RT- Non-Heating. Please see UGI Gas Exhibit SAE-7(a) for the derivation of the Rate R – Non-Heating use per customer value.

Please see UGI Gas Exhibit SAE-7(a) for the derivation of the total Rate RT (Heating and Non-Heating) use per customer value.

SDR-RR-5 (Continued)

The projected CH use per customer was established on a combined Rate N/NT/DS - Heating total basis per the UGI Gas model detailed in Attachment SDR-RR-11(b). Weather normalized sales for Rate NT – Commercial Heating customers and budgeted sales for Rate DS – Commercial Heating were then utilized to derive the separate Rate NT – Commercial Heating, Rate N – Commercial Heating and Rate DS – Commercial Heating use per customer values from the combined Rate N/NT/DS – Commercial Heating value. Please see Attachment SDR-RR-5(d) for the actual and normalized sales utilized for Rate NT – Commercial Heating and Attachment SDR-RR-5(e) for the budget sales for Rate DS – Commercial Heating. Please see UGI Gas Exhibit SAE-7(a) for the derivation of the Rate N – Commercial Heating use per customer value.

Actual sales were normalized for combined Rate N – Commercial Non-Heating, Rate NT - Commercial Non-Heating and Rate DS – Commercial Non-Heating in order to project combined Rate N/NT/DS – Commercial Non-Heating use per customer in total. Please see Attachment SDR-RR-5(f) for the actual and normalized sales utilized for the combined Rate Commercial N/NT/DS-Non-Heating value. Weather normalized sales for Rate NT – Commercial Non-Heating and budgeted sales for Rate DS – Commercial Non-Heating were then utilized to derive the separate Rate NT – Commercial Non-Heating, Rate N – Commercial Non-Heating and Rate DS – Commercial Non-Heating use per customer values from the combined Rate N/NT/DS – Commercial Non-Heating value. Please see Attachment SDR-RR-5(g) for the actual and normalized sales utilized for Rate NT – Commercial Non-Heating and Attachment SDR-RR-5(h) for the budget sales for Rate DS - Commercial Non-Heating. Please see UGI Gas Exhibit SAE-7(a) for the derivation of the Rate N – Commercial Non-Heating use per customer value.

Please see UGI Gas Exhibit SAE-7(a) for the derivation of the total Rate NT (Heating and Non-Heating) use per customer value.

Actual sales were normalized for combined Rate N – Industrial, Rate NT - Industrial and Rate DS – Industrial in order to project combined Rate N/NT/DS – Industrial use per customer in total. Please see Attachment SDR-RR-5(i) for the actual and normalized sales utilized for the combined Rate N/NT/DS - Industrial value. Weather normalized sales for Rate NT – Industrial and budgeted sales for Rate DS – Industrial were then utilized to derive the separate Rate NT – Industrial, Rate N – Industrial and Rate DS – Industrial use per customer values from the combined Rate N/NT/DS – Industrial value. Please see Attachment SDR-RR-5(j) for the actual and normalized sales utilized for Rate NT – Industrial and Attachment SDR-RR-5(k) for the budget sales for Rate DS - Industrial. Please see UGI Gas Exhibit SAE-7(a) For the derivation of the Rate N – Industrial use per customer value.

SDR-RR-5 (Continued)

Please see UGI Gas Exhibit SAE-7(a) for the derivation of the total Rate DS (Heating and Non-Heating) use per customer value.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc. - Gas Division
Residential Heating - Rate RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-03	3,242	21,886	4,584	17,302	455	37.9910	350	(4,005)	17,880	6.75	5.52	
Nov-03	3,208	25,262	4,584	20,678	574	36.0283	672	3,533	28,794	7.87	8.98	
Dec-03	2,854	42,668	4,584	38,084	999	38.1109	952	(1,803)	40,865	14.95	14.32	
Jan-04	2,795	56,316	4,584	51,732	1,357	38.1223	1,120	(9,035)	47,280	20.15	16.92	
Feb-04	2,818	44,506	4,584	39,922	983	40.5972	962	(868)	43,638	15.79	15.49	
Mar-04	2,711	33,249	4,584	28,665	736	38.9677	805	2,704	35,953	12.26	13.26	
Apr-04	2,680	19,041	4,584	14,457	438	33.0030	414	(794)	18,247	7.10	6.81	
May-04	2,666	6,880	4,584	2,297	97	23.6091	164	1,575	8,455	2.58	3.17	
Jun-04	2,651	4,835	4,584	251	52	4.8398	30	(106)	4,729	1.82	1.78	
Jul-04	2,640	4,529	4,529	0	1	0.0000	0	0	4,529	1.72	1.72	
Aug-04	2,624	4,638	4,638	0	21	0.0000	16	0	4,638	1.77	1.77	
Sep-04	2,615	5,662	4,584	1,078	59	18.2817	83	439	6,101	2.17	2.33	92.05
Oct-04	2,719	16,694	4,584	12,111	416	29.1026	350	(1,925)	14,769	6.14	5.43	91.97
Nov-04	2,749	22,851	4,584	18,267	627	29.1419	672	1,316	24,167	8.31	8.79	91.78
Dec-04	2,686	36,205	4,584	31,621	1,005	31.4613	952	(1,670)	34,535	13.48	12.86	90.32
Jan-05	2,661	44,972	4,584	40,388	1,217	33.1845	1,120	(3,221)	41,750	16.90	15.69	89.10
Feb-05	2,641	36,646	4,584	32,062	939	34.1515	962	791	37,437	13.88	14.18	87.79
Mar-05	2,632	35,943	4,584	31,359	942	33.2864	805	(4,564)	31,379	13.66	11.92	86.45
Apr-05	2,620	17,062	4,584	12,478	377	33.1088	414	1,229	18,291	6.51	6.98	86.62
May-05	2,603	11,244	4,584	6,660	268	24.8482	164	(2,585)	8,659	4.32	3.33	86.77
Jun-05	2,613	3,503	3,503	0	16	0.0000	30	0	3,503	1.34	1.34	86.33
Jul-05	2,596	3,713	3,713	0	0	0.0000	0	0	3,713	1.43	1.43	86.05
Aug-05	2,581	4,116	4,116	0	1	0.0000	16	0	4,116	1.59	1.59	85.87
Sep-05	2,559	4,512	3,914	597	35	17.1506	83	826	5,338	1.76	2.09	85.63
Oct-05	2,544	12,749	3,914	8,834	351	25.1601	350	(28)	12,720	5.01	5.00	85.19
Nov-05	2,523	19,963	3,914	16,048	600	26.7670	672	1,939	21,902	7.91	8.68	85.08
Dec-05	2,457	36,407	3,914	32,493	1,121	28.9853	952	(4,899)	31,508	14.82	12.82	85.05
Jan-06	2,363	29,334	3,914	25,420	890	28.5477	1,120	6,553	35,888	12.41	15.19	84.55
Feb-06	2,267	30,811	3,914	26,896	945	28.4599	962	482	31,293	13.59	13.80	84.18
Mar-06	2,244	24,292	3,914	20,378	775	26.2996	805	793	25,086	10.83	11.18	83.43
Apr-06	2,502	13,782	3,914	9,868	390	25.3028	414	608	14,390	5.51	5.75	82.20
May-06	2,587	6,923	3,914	3,009	184	16.3248	164	(332)	6,592	2.68	2.55	81.43
Jun-06	2,608	3,124	3,124	0	44	0.0000	30	0	3,124	1.20	1.20	81.28
Jul-06	2,602	3,932	3,932	0	1	0.0000	0	0	3,932	1.51	1.51	81.36
Aug-06	2,585	4,072	4,072	0	5	0.0000	16	0	4,072	1.58	1.58	81.34
Sep-06	2,579	5,981	4,002	1,979	123	16.1168	83	(641)	5,340	2.32	2.07	81.33
Oct-06	2,548	14,277	4,002	10,275	428	24.0320	350	(1,864)	12,413	5.60	4.87	81.20
Nov-06	2,507	17,192	4,002	13,189	552	23.8801	672	2,858	20,050	6.86	8.00	80.52
Dec-06	2,464	26,384	4,002	22,382	813	27.5219	952	3,819	30,203	10.71	12.26	79.95
Jan-07	2,438	31,729	4,002	27,726	997	27.8099	1,120	3,421	35,149	13.01	14.42	79.18
Feb-07	2,392	38,708	4,002	34,706	1,178	29.4705	962	(6,355)	32,353	16.18	13.53	78.90
Mar-07	2,351	29,239	4,002	25,237	824	30.6176	805	(590)	28,649	12.44	12.19	79.91
Apr-07	2,401	19,949	4,002	15,947	552	28.9066	414	(3,979)	15,969	8.31	6.65	80.81
May-07	2,386	6,783	4,002	2,780	142	19.5170	164	420	7,203	2.84	3.02	81.28
Jun-07	2,361	3,298	3,298	0	23	0.0000	30	0	3,298	1.40	1.40	81.48
Jul-07	2,344	3,551	3,551	0	13	0.0000	0	0	3,551	1.51	1.51	81.48
Aug-07	2,316	3,749	3,749	0	22	0.0000	16	0	3,749	1.62	1.62	81.53
Sep-07	2,278	4,459	3,650	809	72	11.2112	83	122	4,580	1.96	2.01	81.47
Oct-07	2,254	7,713	3,650	4,063	222	18.2851	350	2,337	10,049	3.42	4.46	81.05
Nov-07	2,227	20,397	3,650	16,748	739	22.6475	672	(1,528)	18,869	9.16	8.47	81.53
Dec-07	2,204	28,148	3,650	24,498	1,006	24.3486	952	(1,318)	26,830	12.77	12.17	81.44
Jan-08	2,151	31,126	3,650	27,476	1,051	26.1522	1,120	1,814	32,940	14.47	15.31	82.34
Feb-08	2,111	30,289	3,650	26,640	975	27.3266	962	(352)	29,938	14.35	14.18	83.00
Mar-08	2,070	23,719	3,650	20,069	819	24.5179	805	(332)	23,387	11.46	11.30	82.11
Apr-08	2,019	10,791	3,650	7,141	371	19.2520	414	829	11,620	5.34	5.76	81.21
May-08	1,980	6,720	3,650	3,071	275	11.1644	164	(1,240)	5,481	3.39	2.77	80.96

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Jun-08	1,960	2,733	2,733	0	18	0.0000	30	0	2,733	1.39	1.39	80.96
Jul-08	1,947	2,967	2,967	0	0	0.0000	0	0	2,967	1.52	1.52	80.97
Aug-08	1,935	2,920	2,920	0	14	0.0000	16	0	2,920	1.51	1.51	80.86
Sep-08	1,916	3,942	2,943	998	80	12.4046	83	32	3,973	2.06	2.07	80.92
Oct-08	2,154	11,472	2,943	8,528	468	18.2281	350	(2,149)	9,323	5.33	4.33	80.79
Nov-08	2,802	22,206	2,943	19,262	721	26.6978	672	(1,321)	20,884	7.92	7.45	79.77
Dec-08	2,994	38,967	2,943	36,024	1,016	35.4415	952	(2,283)	36,684	13.02	12.25	79.85
Jan-09	3,137	54,249	2,943	51,305	1,292	39.6950	1,120	(6,847)	47,402	17.29	15.11	79.65
Feb-09	3,124	42,883	2,943	39,940	927	43.0875	962	1,510	44,394	13.73	14.21	79.68
Mar-09	3,096	33,892	2,943	30,948	774	39.9963	805	1,249	35,140	10.95	11.35	79.73
Apr-09	3,079	17,220	2,943	14,277	419	34.0585	414	(177)	17,044	5.59	5.54	79.51
May-09	3,488	8,458	2,943	5,515	179	30.7858	164	(466)	7,992	2.42	2.29	79.03
Jun-09	3,657	5,706	2,943	2,763	41	32.4221	30	(349)	5,358	1.56	1.47	79.10
Jul-09	3,819	6,251	6,251	0	15	0.0000	0	0	6,251	1.64	1.64	79.22
Aug-09	3,782	5,978	5,978	0	16	0.0000	16	0	5,978	1.58	1.58	79.29
Sep-09	3,767	8,105	6,114	1,991	118	16.8874	83	(590)	7,516	2.15	2.00	79.21
Oct-09	3,757	18,655	6,114	12,541	440	28.4957	350	(2,568)	16,088	4.97	4.28	79.16
Nov-09	5,372	31,143	6,114	25,029	571	43.8471	672	4,437	35,579	5.80	6.62	78.33
Dec-09	5,655	77,540	6,114	71,426	1,055	67.6854	952	(6,989)	70,551	13.71	12.48	78.56
Jan-10	5,953	101,671	6,114	95,557	1,157	82.5878	1,120	(3,058)	98,612	17.08	16.57	80.01
Feb-10	7,521	104,397	6,114	98,283	1,014	96.9108	962	(5,055)	99,342	13.88	13.21	79.01
Mar-10	7,708	77,705	6,114	71,591	627	114.1634	805	20,311	98,016	10.08	12.72	80.37
Apr-10	7,765	36,959	6,114	30,845	325	94.9544	414	8,466	45,425	4.76	5.85	80.69
May-10	7,775	19,222	6,114	13,108	153	85.5190	164	917	20,139	2.47	2.59	80.99
Jun-10	7,912	13,184	6,114	7,070	25	90.2367	30	419	13,603	1.67	1.72	81.24
Jul-10	7,995	12,436	12,436	0	4	0.0000	0	0	12,436	1.56	1.56	81.16
Aug-10	7,994	11,765	11,765	0	7	0.0000	16	0	11,765	1.47	1.47	81.05
Sep-10	8,067	13,806	12,100	1,706	67	25.6351	83	422	14,228	1.71	1.76	80.82
Oct-10	8,631	41,097	12,100	28,997	383	75.7411	350	(2,488)	38,609	4.76	4.47	81.01
Nov-10	9,341	80,086	12,100	67,986	669	101.6140	672	298	80,385	8.57	8.61	82.99
Dec-10	10,972	180,306	12,100	168,205	1,162	144.7262	952	(30,426)	149,879	16.43	13.66	84.18
Jan-11	11,639	226,598	12,100	214,498	1,251	171.4996	1,120	(22,418)	204,180	19.47	17.54	85.16
Feb-11	12,074	179,500	12,100	167,400	955	175.2085	962	1,150	180,651	14.87	14.96	86.91
Mar-11	12,279	152,805	12,100	140,705	836	168.2477	805	(5,265)	147,540	12.44	12.02	86.21
Apr-11	12,315	80,577	12,100	68,477	414	165.3461	414	(23)	80,553	6.54	6.54	86.90
May-11	12,304	30,237	12,100	18,137	125	144.6740	164	5,590	35,827	2.46	2.91	87.22
Jun-11	12,459	20,122	12,100	8,021	21	155.0101	30	1,329	21,450	1.62	1.72	87.22
Jul-11	12,497	19,962	19,962	0	1	0.0000	0	0	19,962	1.60	1.60	87.27
Aug-11	12,469	18,453	18,453	0	10	0.0000	16	0	18,453	1.48	1.48	87.27
Sep-11	13,059	25,492	19,207	6,285	74	85.0923	83	778	26,270	1.95	2.01	87.52
Oct-11	14,323	76,755	19,207	57,548	400	144.0076	350	(7,146)	69,610	5.36	4.86	87.91
Nov-11	17,565	124,148	19,207	104,941	559	187.8033	672	21,263	145,411	7.07	8.28	87.58
Dec-11	21,740	243,560	19,207	224,353	843	266.1311	952	29,003	272,564	11.20	12.54	86.46
Jan-12	24,423	348,998	19,207	329,790	1,002	329.2297	1,120	38,947	387,944	14.29	15.88	84.80
Feb-12	25,558	323,666	19,207	304,459	814	374.0066	962	55,335	379,001	12.66	14.83	84.67
Mar-12	26,473	202,487	19,207	183,280	487	376.4569	805	119,768	322,255	7.65	12.17	84.83
Apr-12	26,901	150,838	19,207	131,631	437	301.3969	414	(6,853)	143,985	5.61	5.35	83.64
May-12	27,726	51,048	19,207	31,841	73	437.6367	164	39,931	90,980	1.84	3.28	84.01
Jun-12	28,074	47,719	19,207	28,512	39	369.5168	30	(3,197)	44,522	1.70	1.59	83.87
Jul-12	28,140	43,057	43,057	0	1	0.0000	0	0	43,057	1.53	1.53	83.80
Aug-12	29,133	41,579	41,579	0	7	0.0000	16	0	41,579	1.43	1.43	83.75
Sep-12	29,597	63,792	42,318	21,474	110	195.0598	83	(5,284)	58,508	2.16	1.98	83.72
Oct-12	29,987	124,711	42,318	82,393	335	245.5936	350	3,565	128,276	4.16	4.28	83.13
Nov-12	30,377	309,952	42,318	267,634	785	341.1240	672	(38,398)	271,553	10.20	8.94	83.79
Dec-12	30,927	370,508	42,318	328,190	853	384.5490	952	37,901	408,409	11.98	13.21	84.46
Jan-13	32,253	489,684	42,318	447,366	1,047	427.3128	1,120	31,224	520,908	15.18	16.15	84.73

UGI Utilities, Inc. - Gas Division
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Feb-13	32,392	495,314	42,318	452,996	974	464.9974	962	(5,668)	489,645	15.29	15.12	85.02
Mar-13	32,467	436,598	42,318	394,280	884	446.2572	805	(35,043)	401,555	13.45	12.37	85.21
Apr-13	32,377	217,377	42,318	175,059	427	410.2093	414	(5,232)	212,145	6.71	6.55	86.41
May-13	32,271	81,338	42,318	39,020	178	218.7492	164	(3,145)	78,193	2.52	2.42	85.55
Jun-13	32,398	44,643	42,318	2,325	21	110.8142	30	1,000	45,642	1.38	1.41	85.38
Jul-13	32,542	49,405	49,405	0	4	0.0000	0	0	49,405	1.52	1.52	85.36
Aug-13	32,620	48,748	48,748	0	12	0.0000	16	0	48,748	1.49	1.49	85.43
Sep-13	33,115	79,156	49,077	30,079	143	210.8278	83	(12,580)	66,575	2.39	2.01	85.46
Oct-13	33,746	138,652	49,077	89,575	327	273.6270	350	6,194	144,846	4.11	4.29	85.48
Nov-13	36,732	343,595	49,077	294,518	773	381.0695	672	(38,439)	305,155	9.35	8.31	84.85
Dec-13	39,635	542,534	49,077	493,458	1,012	487.6685	952	(29,197)	513,337	13.69	12.95	84.59
Jan-14	40,825	775,157	49,077	726,081	1,310	554.1929	1,120	(105,385)	669,773	18.99	16.41	84.85
Feb-14	41,145	700,114	49,077	651,037	1,114	584.4399	962	(88,806)	611,308	17.02	14.86	84.59
Mar-14	41,156	591,900	49,077	542,824	976	555.9691	805	(95,269)	496,632	14.38	12.07	84.29
Apr-14	39,996	290,388	49,077	241,312	467	517.1654	414	(27,205)	263,183	7.26	6.58	84.32
May-14	39,257	102,499	49,077	53,423	152	350.4194	164	4,046	106,545	2.61	2.71	84.61
Jun-14	38,710	55,661	49,077	6,585	14	485.8249	30	7,990	63,651	1.44	1.64	84.84
Jul-14	38,359	57,939	57,939	0	10	0.0000	0	0	57,939	1.51	1.51	84.84
Aug-14	39,022	57,536	57,536	0	13	0.0000	16	0	57,536	1.47	1.47	84.82
Sep-14	39,554	77,654	57,737	19,916	98	202.3980	83	(3,117)	74,536	1.96	1.88	84.69
Oct-14	40,571	153,659	57,737	95,922	303	316.8540	350	14,977	168,636	3.79	4.16	84.55
Nov-14	42,137	406,715	57,737	348,977	759	459.8146	672	(39,982)	366,733	9.65	8.70	84.95
Dec-14	43,327	559,097	57,737	501,359	909	551.4105	952	23,583	582,680	12.90	13.45	85.45
Jan-15	44,529	783,215	57,737	725,477	1,231	589.3861	1,120	(65,365)	717,850	17.59	16.12	85.16
Feb-15	45,059	855,825	57,737	798,088	1,275	625.9176	962	(195,955)	659,870	18.99	14.64	84.95
Mar-15	45,335	655,824	57,737	598,087	960	623.0237	805	(96,553)	559,271	14.47	12.34	85.22
Apr-15	45,044	276,725	57,737	218,988	403	543.2216	414	5,906	282,631	6.14	6.27	84.91
May-15	46,245	90,809	57,737	33,072	83	399.4403	164	32,436	123,245	1.96	2.67	84.86
Jun-15	47,373	65,898	57,737	8,160	32	251.7466	30	(608)	65,290	1.39	1.38	84.60
Jul-15	47,085	70,772	70,772	0	4	0.0000	0	0	70,772	1.50	1.50	84.59
Aug-15	46,832	67,608	67,608	0	6	0.0000	16	0	67,608	1.44	1.44	84.56
Sep-15	46,845	74,435	69,190	5,245	42	123.5546	83	5,010	79,445	1.59	1.70	84.37
Oct-15	47,740	232,342	69,190	163,152	378	431.7648	350	(12,035)	220,307	4.87	4.61	84.83
Nov-15	48,232	316,760	69,190	247,570	508	487.0598	672	79,734	396,494	6.57	8.22	84.35
Dec-15	49,454	411,448	69,190	342,258	625	547.8129	952	179,260	590,708	8.32	11.94	82.84
Jan-16	49,653	798,392	69,190	729,202	1,130	645.4790	1,120	(6,266)	792,126	16.08	15.95	82.67
Feb-16	49,526	703,638	69,190	634,448	936	678.0323	962	17,819	721,457	14.21	14.57	82.60
Mar-16	49,288	452,398	69,190	383,208	582	658.7573	805	147,091	599,489	9.18	12.16	82.42
Apr-16	48,927	312,465	69,190	243,276	468	519.7581	414	(28,096)	284,370	6.39	5.81	81.96
May-16	49,234	158,152	69,190	88,962	221	402.7513	164	(22,911)	135,241	3.21	2.75	82.04
Jun-16	49,333	72,533	69,190	3,343	25	134.8360	30	702	73,235	1.47	1.48	82.15
Jul-16	49,251	71,857	71,857	0	2	0.0000	0	0	71,857	1.46	1.46	82.11
Aug-16	48,935	66,698	66,698	0	3	0.0000	16	0	66,698	1.36	1.36	82.02
Sep-16	48,674	82,081	69,278	12,803	53	243.6988	83	7,424	89,505	1.69	1.84	82.17
Oct-16	48,654	195,780	69,278	126,502	324	390.7269	350	10,253	206,032	4.02	4.23	81.79
Nov-16	49,037	365,343	69,278	296,065	589	502.8390	672	41,843	407,186	7.45	8.30	81.87
Dec-16	50,219	675,065	69,278	605,787	973	622.8528	952	(12,831)	662,234	13.44	13.19	83.11
Jan-17	50,603	750,354	69,278	681,077	961	708.7627	1,120	112,738	863,092	14.83	17.06	84.22
Feb-17	50,556	573,885	69,278	504,608	719	702.2587	962	170,965	744,851	11.35	14.73	84.38
Mar-17	50,832	650,253	69,278	580,975	879	660.5964	805	(49,195)	601,058	12.79	11.82	84.04
Apr-17	50,931	240,310	69,278	171,032	264	647.5644	414	97,060	337,369	4.72	6.62	84.86
May-17	52,020	160,137	69,278	90,859	205	442.7107	164	(18,255)	141,882	3.08	2.73	84.84
Jun-17	51,976	74,808	69,278	5,531	33	166.2140	30	(544)	74,264	1.44	1.43	84.78
Jul-17	53,106	76,976	76,976	0	2	0.0000	0	0	76,976	1.45	1.45	84.77
Aug-17	54,163	75,610	75,610	0	19	0.0000	16	0	75,610	1.40	1.40	84.80
Sep-17	56,647	43,611	43,611	0	89	0.0000	83	0	43,611	0.77	0.77	83.73

UGI Utilities, Inc. - Gas Division
Residential Heating - Rate RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-17	59,641	117,487	76,293	41,194	227	181.1755	350	22,217	139,704	1.97	2.34	81.84
Nov-17	60,807	688,760	76,293	612,467	684	895.5539	672	(10,655)	678,105	11.33	11.15	84.69
Dec-17	66,212	1,078,481	76,293	1,002,188	1,087	921.6229	952	(124,803)	953,678	16.29	14.40	85.91
Jan-18	68,364	1,218,492	76,293	1,142,199	1,156	988.3791	1,120	(35,214)	1,183,277	17.82	17.31	86.16
Feb-18	68,522	794,715	76,293	718,423	775	927.4334	962	173,768	968,484	11.60	14.13	85.56
Mar-18	69,874	891,791	76,293	815,498	905	901.4745	805	(89,811)	801,980	12.76	11.48	85.21
Apr-18	71,254	564,679	76,293	488,386	573	852.6619	414	(135,384)	429,295	7.92	6.02	84.61
May-18	72,195	137,678	76,293	61,385	69	894.5091	164	85,315	222,992	1.91	3.09	84.98
Jun-18	71,932	127,047	76,293	50,754	29	873.5855	30	1,059	128,106	1.77	1.78	85.33
Jul-18	71,926	88,450	88,450	0	2	0.0000	0	0	88,450	1.23	1.23	85.11
Aug-18	72,549	86,905	86,905	0	2	0.0000	16	0	86,905	1.20	1.20	84.91
Sep-18	73,463	125,166	87,678	37,488	61	212.4372	83	4,622	129,788	1.70	1.77	85.91
Oct-18	73,696	354,681	87,678	267,004	370	721.6889	350	(14,412)	340,269	4.81	4.62	88.18
Nov-18	74,137	860,507	87,678	772,830	773	1,000.3046	672	(100,625)	759,882	11.61	10.25	87.28
Dec-18	76,256	988,132	87,678	900,454	886	1,016.3333	952	67,095	1,055,227	12.96	13.84	86.71
Jan-19	76,628	1,341,126	87,678	1,253,448	1,146	1,093.5441	1,120	(28,678)	1,312,447	17.50	17.13	86.53
Feb-19	76,446	1,091,967	87,678	1,004,289	904	1,110.8709	962	64,368	1,156,336	14.28	15.13	87.52
Mar-19	75,990	883,540	87,678	795,862	826	963.9796	805	(19,859)	863,681	11.63	11.37	87.41
Apr-19	75,260	331,836	87,678	244,158	319	764.4659	414	72,331	404,167	4.41	5.37	86.76
May-19	75,077	199,942	87,678	112,265	121	929.3933	164	40,156	240,098	2.66	3.20	86.87
Jun-19	75,146	116,475	87,678	28,797	25	846.9296	30	4,320	120,794	1.55	1.61	86.69
Jul-19	74,995	101,828	101,828	0	1	0.0000	0	0	101,828	1.36	1.36	86.82
Aug-19	74,851	89,446	89,446	0	2	0.0000	16	0	89,446	1.19	1.19	86.82
Sep-19	75,895	111,708	95,637	16,071	29	555.0710	83	30,000	141,708	1.47	1.87	86.92
Oct-19	76,033	250,892	95,637	155,255	266	583.6143	350	49,010	299,902	3.30	3.94	86.25
Nov-19	76,418	741,020	95,637	645,383	764	845.1167	672	(77,464)	663,556	9.70	8.68	84.68
Dec-19	77,332	1,236,628	95,637	1,140,991	923	1,236.1090	952	35,785	1,272,413	15.99	16.45	87.30
Jan-20	77,883	1,054,731	95,637	959,094	916	1,047.4705	1,120	214,073	1,268,804	13.54	16.29	86.46
Feb-20	78,311	851,415	95,637	755,778	822	919.4794	962	128,761	980,177	10.87	12.52	83.85
Mar-20	79,541	623,265	95,637	527,628	595	887.4032	805	186,731	809,997	7.84	10.18	82.67
Apr-20	80,169	627,083	95,637	531,445	488	1,089.0801	414	(80,566)	546,516	7.82	6.82	84.12
May-20	79,954	291,418	95,637	195,781	217	902.1175	164	(47,833)	243,585	3.64	3.05	83.96
Jun-20	79,563	170,322	95,637	74,685	13	995.5988	30	16,769	187,091	2.14	2.35	84.71
Jul-20	78,858	118,004	118,004	0	0	0.0000	0	0	118,004	1.50	1.50	84.85
Aug-20	78,276	82,867	82,867	0	0	0.0000	16	0	82,867	1.06	1.06	84.71
Sep-20	77,632	151,435	100,435	51,000	88	580.9002	83	(2,785)	148,650	1.95	1.91	84.76
Oct-20	77,136	275,971	100,435	175,536	309	568.0778	350	23,291	299,263	3.58	3.88	84.69
Nov-20	77,491	668,895	100,435	568,460	507	1,121.2223	672	185,002	853,897	8.63	11.02	87.03
Dec-20	77,815	998,469	100,435	898,034	940	955.3552	952	11,464	1,009,933	12.83	12.98	83.55
Jan-21	78,522	1,235,048	100,435	1,134,613	1,025	1,106.9395	1,120	105,159	1,340,208	15.73	17.07	84.33
Feb-21	78,025	1,171,466	100,435	1,071,031	969	1,105.2953	962	(7,737)	1,163,729	15.01	14.91	86.73
Mar-21	77,392	760,266	100,435	659,831	649	1,016.6881	805	158,603	918,869	9.82	11.87	88.42
Apr-21	76,480	423,331	100,435	322,896	388	832.2052	414	21,637	444,968	5.54	5.82	87.42
May-21	75,683	223,835	100,435	123,400	204	604.9000	164	(24,196)	199,639	2.96	2.64	87.01
Jun-21	74,733	113,406	100,435	12,971	12	718.5526	30	12,934	126,340	1.52	1.69	86.35
Jul-21	74,169	107,937	107,937	0	0	0.0000	0	0	107,937	1.46	1.46	86.31
Aug-21	73,677	105,994	105,994	0	0	0.0000	16	0	105,994	1.44	1.44	86.69
Sep-21	73,505	100,869	100,869	0	53	0.0000	83	0	100,869	1.37	1.37	86.15

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Combined Rate R and RT

	[1]	[2]	[3] *	[4] = [2] -[3]	[5]	[6] = [4] / [5]	[7]	[8]=([7] -[5])*[6]	[9] = [8] + [2]			
Month	Number of Customers	Actual Sales	Base Load	Temp Sensitive Load	Actual DD's	Temp Sensitive Load/DD	Normal DD's	Normalized Sales Adj	Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-03	60,479	75,992	58,377	17,614	455	38.6764	350	(4,078)	71,914	1.26	1.19	
Nov-03	60,524	94,163	58,377	35,786	574	62.3519	672	6,114	100,278	1.56	1.66	
Dec-03	60,528	116,210	58,377	57,833	999	57.8730	952	(2,738)	113,472	1.92	1.87	
Jan-04	60,363	131,202	58,377	72,825	1,357	53.6656	1,120	(12,719)	118,483	2.17	1.96	
Feb-04	60,182	126,651	58,377	68,274	983	69.4276	962	(1,484)	125,167	2.10	2.08	
Mar-04	59,985	107,861	58,377	49,484	736	67.2686	805	4,667	112,528	1.80	1.88	
Apr-04	60,024	89,994	58,377	31,617	438	72.1753	414	(1,737)	88,258	1.50	1.47	
May-04	59,867	80,201	58,377	21,824	97	69.7219	164	4,652	84,853	1.34	1.42	
Jun-04	59,542	60,330	58,377	1,953	52	37.5770	30	(825)	59,504	1.01	1.00	
Jul-04	59,332	58,742	58,742	0	1	0.0000	0	0	58,742	0.99	0.99	
Aug-04	59,200	58,012	58,012	0	21	0.0000	16	0	58,012	0.98	0.98	
Sep-04	59,312	62,495	58,377	4,118	59	69.8401	83	1,679	64,174	1.05	1.08	17.58
Oct-04	59,373	73,457	58,377	15,080	416	36.2382	350	(2,397)	71,061	1.24	1.20	17.59
Nov-04	59,321	90,718	58,377	32,341	627	51.5949	672	2,331	93,049	1.53	1.57	17.50
Dec-04	59,331	109,260	58,377	50,883	1,005	50.6255	952	(2,687)	106,573	1.84	1.80	17.42
Jan-05	59,194	128,020	58,377	69,643	1,217	57.2217	1,120	(5,555)	122,465	2.16	2.07	17.53
Feb-05	59,055	116,874	58,377	58,497	939	62.3086	962	1,444	118,318	1.98	2.00	17.45
Mar-05	58,896	116,862	58,377	58,485	942	62.0796	805	(8,511)	108,351	1.98	1.84	17.41
Apr-05	58,666	95,615	58,377	37,238	377	98.8046	414	3,667	99,282	1.63	1.69	17.63
May-05	58,463	74,733	58,377	16,356	268	61.0222	164	(6,348)	68,385	1.28	1.17	17.39
Jun-05	58,180	61,479	61,479	0	16	0.0000	30	0	61,479	1.06	1.06	17.44
Jul-05	57,849	58,179	58,179	0	0	0.0000	0	0	58,179	1.01	1.01	17.46
Aug-05	57,626	50,028	50,028	0	1	0.0000	16	0	50,028	0.87	0.87	17.35
Sep-05	57,440	52,428	52,428	0	35	0.0000	83	0	52,428	0.91	0.91	17.18
Oct-05	57,407	64,843	54,103	10,739	351	30.5862	350	(34)	64,808	1.13	1.13	17.11
Nov-05	57,529	84,302	54,103	30,199	600	50.3695	672	3,649	87,952	1.47	1.53	17.07
Dec-05	57,601	113,229	54,103	59,126	1,121	52.7432	952	(8,914)	104,315	1.97	1.81	17.09
Jan-06	57,451	126,594	54,103	72,491	890	81.4105	1,120	18,689	145,283	2.20	2.53	17.55
Feb-06	57,455	109,323	54,103	55,219	945	58.4294	962	990	110,312	1.90	1.92	17.46
Mar-06	57,477	107,146	54,103	53,043	775	68.4567	805	2,065	109,211	1.86	1.90	17.52
Apr-06	57,269	86,360	54,103	32,257	390	82.7125	414	1,986	88,346	1.51	1.54	17.37
May-06	56,982	72,253	54,103	18,150	184	98.4706	164	(2,001)	70,252	1.27	1.23	17.44
Jun-06	56,629	58,588	54,103	4,484	44	90.5916	30	(1,246)	57,342	1.03	1.01	17.39
Jul-06	56,349	54,535	54,535	0	1	0.0000	0	0	54,535	0.97	0.97	17.35
Aug-06	56,159	48,857	48,857	0	5	0.0000	16	0	48,857	0.87	0.87	17.36
Sep-06	56,089	54,106	51,696	2,410	123	19.6326	83	(781)	53,326	0.96	0.95	17.39
Oct-06	56,028	69,704	51,696	18,008	428	42.1178	350	(3,267)	66,437	1.24	1.19	17.45
Nov-06	56,036	86,335	51,696	34,639	552	62.7159	672	7,506	93,841	1.54	1.67	17.60
Dec-06	56,222	104,421	51,696	52,725	813	64.8337	952	8,997	113,418	1.86	2.02	17.80
Jan-07	56,071	109,790	51,696	58,094	997	58.2685	1,120	7,167	116,957	1.96	2.09	17.36
Feb-07	56,120	112,984	51,696	61,288	1,178	52.0428	962	(11,223)	101,761	2.01	1.81	17.25
Mar-07	56,165	125,501	51,696	73,805	824	89.5398	805	(1,725)	123,776	2.23	2.20	17.56
Apr-07	56,003	94,529	51,696	42,833	552	77.6426	414	(10,689)	83,840	1.69	1.50	17.51
May-07	55,767	72,575	51,696	20,879	142	83.5912	164	1,800	74,375	1.30	1.33	17.61
Jun-07	55,631	53,321	51,696	1,625	23	70.9442	30	504	53,824	0.96	0.97	17.57
Jul-07	55,279	50,624	50,624	0	13	0.0000	0	0	50,624	0.92	0.92	17.52
Aug-07	54,825	48,575	48,575	0	22	0.0000	16	0	48,575	0.89	0.89	17.53
Sep-07	54,608	54,287	49,599	4,688	72	64.9721	83	705	54,992	0.99	1.01	17.59
Oct-07	54,605	60,897	49,599	11,297	222	50.8413	350	6,497	67,394	1.12	1.23	17.64
Nov-07	54,779	77,824	49,599	28,225	739	38.1679	672	(2,576)	75,248	1.42	1.37	17.34
Dec-07	54,878	119,283	49,599	69,684	1,006	69.2578	952	(3,750)	115,533	2.17	2.11	17.42
Jan-08	54,618	131,264	49,599	81,665	1,051	77.7298	1,120	5,393	136,657	2.40	2.50	17.84
Feb-08	54,640	117,414	49,599	67,815	975	69.5634	962	(895)	116,519	2.15	2.13	18.16
Mar-08	54,663	113,204	49,599	63,604	819	77.7029	805	(1,053)	112,150	2.07	2.05	18.01
Apr-08	54,427	83,287	49,599	33,687	371	90.8179	414	3,911	87,198	1.53	1.60	18.11
May-08	54,197	65,804	49,599	16,204	275	58.9157	164	(6,542)	59,262	1.21	1.09	17.87

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Combined Rate R and RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Jun-08	53,805	57,473	49,599	7,874	18	74.8668	30	903	58,376	1.07	1.08	17.99
Jul-08	53,302	48,435	48,435	0	0	0.0000	0	0	48,435	0.91	0.91	17.98
Aug-08	53,103	49,632	49,632	0	14	0.0000	16	0	49,632	0.93	0.93	18.03
Sep-08	52,929	53,622	49,033	4,589	80	57.0372	83	145	53,767	1.01	1.02	18.04
Oct-08	52,802	64,735	49,033	15,702	468	33.5608	350	(3,956)	60,780	1.23	1.15	17.96
Nov-08	52,751	93,794	49,033	44,760	721	62.0384	672	(3,071)	90,723	1.78	1.72	18.30
Dec-08	52,467	125,999	49,033	76,966	1,016	75.7218	952	(4,878)	121,120	2.40	2.31	18.51
Jan-09	52,048	131,018	49,033	81,984	1,292	63.4315	1,120	(10,941)	120,077	2.52	2.31	18.31
Feb-09	51,981	120,433	49,033	71,399	927	77.0263	962	2,700	123,133	2.32	2.37	18.55
Mar-09	52,010	104,573	49,033	55,539	774	71.7774	805	2,241	106,814	2.01	2.05	18.55
Apr-09	51,795	77,119	49,033	28,086	419	67.0013	414	(348)	76,772	1.49	1.48	18.43
May-09	51,566	65,828	49,033	16,795	179	93.7599	164	(1,419)	64,410	1.28	1.25	18.58
Jun-09	51,258	53,742	49,033	4,709	41	80.3806	30	(864)	52,878	1.05	1.03	18.53
Jul-09	51,119	52,435	52,435	0	15	0.0000	0	0	52,435	1.03	1.03	18.65
Aug-09	50,920	50,389	50,389	0	16	0.0000	16	0	50,389	0.99	0.99	18.70
Sep-09	50,625	51,048	51,048	0	118	0.0000	83	0	51,048	1.01	1.01	18.70
Oct-09	50,560	69,057	51,412	17,645	440	40.0918	350	(3,613)	65,444	1.37	1.29	18.84
Nov-09	50,533	86,170	51,412	34,758	571	60.8916	672	6,161	92,331	1.71	1.83	18.95
Dec-09	50,455	100,525	51,412	49,113	1,055	46.5410	952	(4,806)	95,719	1.99	1.90	18.53
Jan-10	49,942	124,178	51,412	72,766	1,157	62.8906	1,120	(2,329)	121,850	2.49	2.44	18.67
Feb-10	49,836	99,605	51,412	48,193	1,014	47.5204	962	(2,479)	97,127	2.00	1.95	18.25
Mar-10	49,780	94,320	51,412	42,907	627	68.4229	805	12,173	106,493	1.89	2.14	18.33
Apr-10	49,546	66,731	51,412	15,319	325	47.1597	414	4,205	70,936	1.35	1.43	18.28
May-10	49,174	61,319	51,412	9,907	153	64.6365	164	693	62,012	1.25	1.26	18.29
Jun-10	48,858	48,822	48,822	0	25	0.0000	30	0	48,822	1.00	1.00	18.26
Jul-10	48,667	43,594	43,594	0	4	0.0000	0	0	43,594	0.90	0.90	18.13
Aug-10	48,517	41,998	41,998	0	7	0.0000	16	0	41,998	0.87	0.87	18.01
Sep-10	48,462	47,279	42,796	4,483	67	67.3699	83	1,109	48,388	0.98	1.00	18.00
Oct-10	48,545	59,577	42,796	16,781	383	43.8310	350	(1,440)	58,137	1.23	1.20	17.90
Nov-10	48,569	76,929	42,796	34,133	669	51.0163	672	150	77,079	1.58	1.59	17.66
Dec-10	48,443	108,623	42,796	65,826	1,162	56.6379	952	(11,907)	96,716	2.24	2.00	17.76
Jan-11	47,991	116,030	42,796	73,234	1,251	58.5533	1,120	(7,654)	108,376	2.42	2.26	17.58
Feb-11	47,973	102,921	42,796	60,125	955	62.9293	962	413	103,334	2.15	2.15	17.78
Mar-11	48,012	90,052	42,796	47,256	836	56.5067	805	(1,768)	88,284	1.88	1.84	17.48
Apr-11	47,795	80,760	42,796	37,963	414	91.6680	414	(13)	80,747	1.69	1.69	17.74
May-11	47,451	59,439	42,796	16,643	125	74.0874	164	2,862	62,301	1.25	1.31	17.79
Jun-11	47,211	45,266	42,796	2,470	21	74.0874	30	635	45,901	0.96	0.97	17.77
Jul-11	47,000	42,827	42,827	0	1	0.0000	0	0	42,827	0.91	0.91	17.78
Aug-11	46,825	41,496	41,496	0	10	0.0000	16	0	41,496	0.89	0.89	17.80
Sep-11	46,821	46,490	42,162	4,328	74	58.5944	83	535	47,025	0.99	1.00	17.81
Oct-11	46,863	63,940	42,162	21,778	400	54.4971	350	(2,704)	61,236	1.36	1.31	17.92
Nov-11	46,739	78,579	42,162	36,417	559	65.1714	672	7,379	85,957	1.68	1.84	18.17
Dec-11	46,660	99,524	42,162	57,362	843	68.0440	952	7,416	106,940	2.13	2.29	18.47
Jan-12	46,313	111,029	42,162	68,867	1,002	68.7500	1,120	8,133	119,162	2.40	2.57	18.78
Feb-12	46,099	92,179	42,162	50,017	814	61.4421	962	9,091	101,269	2.00	2.20	18.82
Mar-12	46,063	84,177	42,162	42,015	487	86.2987	805	27,456	111,632	1.83	2.42	19.41
Apr-12	45,778	59,422	42,162	17,260	437	39.5195	414	(899)	58,523	1.30	1.28	19.00
May-12	45,498	52,682	42,162	10,520	73	62.9091	164	5,740	58,422	1.16	1.28	18.97
Jun-12	45,250	43,552	42,162	1,390	39	35.9558	30	(311)	43,241	0.96	0.96	18.95
Jul-12	45,146	38,946	38,946	0	1	0.0000	0	0	38,946	0.86	0.86	18.90
Aug-12	45,016	41,664	41,664	0	7	0.0000	16	0	41,664	0.93	0.93	18.94
Sep-12	45,078	41,582	40,305	1,278	110	11.6046	83	(314)	41,268	0.92	0.92	18.85
Oct-12	45,119	61,472	40,305	21,167	335	63.0949	350	916	62,388	1.36	1.38	18.93
Nov-12	44,978	81,363	40,305	41,058	785	52.3323	672	(5,891)	75,472	1.81	1.68	18.77
Dec-12	44,632	108,354	40,305	68,049	853	79.7350	952	7,859	116,213	2.43	2.60	19.08
Jan-13	44,267	117,188	40,305	76,883	1,047	73.4371	1,120	5,366	122,554	2.65	2.77	19.28

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Combined Rate R and RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Feb-13	44,136	112,723	40,305	72,418	974	74.3366	962	(906)	111,817	2.55	2.53	19.61
Mar-13	44,066	102,359	40,305	62,054	884	70.2348	805	(5,515)	96,844	2.32	2.20	19.39
Apr-13	43,816	83,489	40,305	43,184	427	72.2857	414	(922)	82,567	1.91	1.88	19.99
May-13	43,652	53,264	40,305	12,959	178	72.6502	164	(1,044)	52,220	1.22	1.20	19.90
Jun-13	43,406	43,584	40,305	3,279	21	72.4680	30	654	44,238	1.00	1.02	19.97
Jul-13	43,256	38,466	38,466	0	4	0.0000	0	0	38,466	0.89	0.89	19.99
Aug-13	43,180	40,046	40,046	0	12	0.0000	16	0	40,046	0.93	0.93	20.00
Sep-13	43,158	43,708	39,256	4,452	143	31.2063	83	(1,862)	41,846	1.01	0.97	20.05
Oct-13	43,210	59,593	39,256	20,338	327	62.1257	350	1,406	61,000	1.38	1.41	20.08
Nov-13	43,087	82,899	39,256	43,643	773	56.4685	672	(5,696)	77,203	1.92	1.79	20.19
Dec-13	42,228	116,199	39,256	76,943	1,012	76.0402	952	(4,553)	111,646	2.75	2.64	20.23
Jan-14	41,379	127,169	39,256	87,913	1,310	67.1014	1,120	(12,760)	114,409	3.07	2.76	20.23
Feb-14	41,184	115,083	39,256	75,827	1,114	68.0702	962	(10,343)	104,739	2.79	2.54	20.24
Mar-14	41,038	107,381	39,256	68,125	976	69.7752	805	(11,956)	95,425	2.62	2.33	20.37
Apr-14	40,741	71,256	39,256	32,000	467	68.5813	414	(3,608)	67,648	1.75	1.66	20.14
May-14	40,538	53,579	39,256	14,323	152	69.1783	164	799	54,378	1.32	1.34	20.29
Jun-14	40,262	39,805	39,805	0	14	0.0000	30	0	39,805	0.99	0.99	20.26
Jul-14	40,102	37,650	37,650	0	10	0.0000	0	0	37,650	0.94	0.94	20.31
Aug-14	39,939	39,476	39,476	0	13	0.0000	16	0	39,476	0.99	0.99	20.37
Sep-14	39,971	38,299	38,299	0	98	0.0000	83	0	38,299	0.96	0.96	20.36
Oct-14	40,073	53,257	38,563	14,694	303	48.5386	350	2,294	55,552	1.33	1.39	20.33
Nov-14	40,076	81,006	38,563	42,443	759	55.9237	672	(4,863)	76,144	2.02	1.90	20.44
Dec-14	39,411	105,661	38,563	67,098	909	73.7968	952	3,156	108,818	2.68	2.76	20.56
Jan-15	38,956	117,426	38,563	78,863	1,231	64.0689	1,120	(7,105)	110,320	3.01	2.83	20.62
Feb-15	38,863	114,470	38,563	75,907	1,275	59.5317	962	(18,638)	95,832	2.95	2.47	20.55
Mar-15	38,765	111,531	38,563	72,968	960	76.0105	805	(11,780)	99,751	2.88	2.57	20.79
Apr-15	38,540	66,078	38,563	27,515	403	68.2533	414	742	66,820	1.71	1.73	20.87
May-15	38,196	43,730	38,563	5,167	83	62.4103	164	5,068	48,798	1.14	1.28	20.80
Jun-15	37,920	35,566	35,566	0	32	0.0000	30	0	35,566	0.94	0.94	20.75
Jul-15	37,826	35,079	35,079	0	4	0.0000	0	0	35,079	0.93	0.93	20.74
Aug-15	37,760	34,143	34,143	0	6	0.0000	16	0	34,143	0.90	0.90	20.66
Sep-15	37,723	35,986	34,611	1,375	42	32.3938	83	1,314	37,300	0.95	0.99	20.69
Oct-15	37,865	52,398	34,611	17,787	378	47.0721	350	(1,312)	51,086	1.38	1.35	20.65
Nov-15	37,830	65,539	34,611	30,928	508	60.8471	672	9,961	75,500	1.73	2.00	20.75
Dec-15	37,587	75,741	34,611	41,130	625	65.8319	952	21,542	97,283	2.02	2.59	20.57
Jan-16	37,437	98,164	34,611	63,553	1,130	56.2563	1,120	(546)	97,618	2.62	2.61	20.35
Feb-16	37,255	97,246	34,611	62,635	936	66.9376	962	1,759	99,005	2.61	2.66	20.54
Mar-16	37,228	70,413	34,611	35,802	582	61.5463	805	13,742	84,156	1.89	2.26	20.23
Apr-16	36,977	54,662	34,611	20,051	468	42.8389	414	(2,316)	52,346	1.48	1.42	19.91
May-16	36,905	46,509	34,611	11,898	221	53.8657	164	(3,064)	43,445	1.26	1.18	19.81
Jun-16	36,494	35,614	34,611	1,002	25	40.4314	30	210	35,824	0.98	0.98	19.85
Jul-16	35,770	31,735	31,735	0	2	0.0000	0	0	31,735	0.89	0.89	19.81
Aug-16	35,684	29,315	29,315	0	3	0.0000	16	0	29,315	0.82	0.82	19.73
Sep-16	35,244	31,669	30,525	1,143	53	21.7637	83	663	32,332	0.90	0.92	19.66
Oct-16	35,331	42,070	30,525	11,545	324	35.6587	350	936	43,006	1.19	1.22	19.53
Nov-16	35,379	48,302	30,525	17,776	589	30.1917	672	2,512	50,814	1.37	1.44	18.97
Dec-16	35,223	69,057	30,525	38,532	973	39.6171	952	(816)	68,241	1.96	1.94	18.32
Jan-17	34,895	78,760	30,525	48,235	961	50.1955	1,120	7,984	86,744	2.26	2.49	18.20
Feb-17	34,832	61,723	30,525	31,198	719	43.4182	962	10,570	72,294	1.77	2.08	17.61
Mar-17	34,889	63,653	30,525	33,128	879	37.6680	805	(2,805)	60,848	1.82	1.74	17.10
Apr-17	34,152	46,482	30,525	15,956	264	60.4147	414	9,055	55,537	1.36	1.63	17.31
May-17	33,676	36,467	30,525	5,942	205	28.9528	164	(1,194)	35,274	1.08	1.05	17.18
Jun-17	33,548	30,810	30,525	285	33	8.5535	30	(28)	30,782	0.92	0.92	17.11
Jul-17	33,451	31,371	31,371	0	2	0.0000	0	0	31,371	0.94	0.94	17.16
Aug-17	33,445	29,228	29,228	0	19	0.0000	16	0	29,228	0.87	0.87	17.22
Sep-17	33,305	22,249	22,249	0	89	0.0000	83	0	22,249	0.67	0.67	16.97

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Combined Rate R and RT

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Oct-17	33,385	47,968	30,299	17,668	227	28.2328	350	3,462	51,430	1.44	1.54	17.29
Nov-17	33,512	42,171	30,299	11,872	684	17.3592	672	(207)	41,965	1.26	1.25	17.11
Dec-17	33,648	72,825	30,299	42,525	1,087	39.1065	952	(5,296)	67,529	2.16	2.01	17.18
Jan-18	33,094	83,330	30,299	53,031	1,156	45.8893	1,120	(1,635)	81,695	2.52	2.47	17.16
Feb-18	32,119	53,749	30,299	23,449	775	30.2713	962	5,672	59,420	1.67	1.85	16.93
Mar-18	31,999	50,194	30,299	19,894	905	21.9919	805	(2,191)	48,003	1.57	1.50	16.69
Apr-18	31,887	44,861	30,299	14,561	573	25.4223	414	(4,037)	40,824	1.41	1.28	16.34
May-18	31,808	29,831	29,831	0	69	0.0000	164	0	29,831	0.94	0.94	16.23
Jun-18	31,770	30,283	30,283	0	29	0.0000	30	0	30,283	0.95	0.95	16.27
Jul-18	31,674	23,704	23,704	0	2	0.0000	0	0	23,704	0.75	0.75	16.08
Aug-18	31,572	21,088	21,088	0	2	0.0000	16	0	21,088	0.67	0.67	15.87
Sep-18	31,538	28,742	22,396	6,345	61	24.9983	83	544	29,286	0.91	0.93	16.13
Oct-18	31,508	39,854	22,396	17,457	370	47.1862	350	(942)	38,911	1.26	1.23	15.83
Nov-18	31,685	50,068	22,396	27,671	773	35.8161	672	(3,603)	46,465	1.58	1.47	16.04
Dec-18	31,763	64,627	22,396	42,231	886	47.6655	952	3,147	67,774	2.03	2.13	16.17
Jan-19	31,728	72,933	22,396	50,537	1,146	44.0899	1,120	(1,156)	71,777	2.30	2.26	15.96
Feb-19	30,638	64,452	22,396	42,056	904	46.5192	962	2,696	67,148	2.10	2.19	16.31
Mar-19	30,501	51,834	22,396	29,438	826	35.6562	805	(735)	51,100	1.70	1.68	16.48
Apr-19	30,501	34,080	22,396	11,683	319	36.5808	414	3,461	37,541	1.12	1.23	16.43
May-19	30,374	32,421	22,396	10,025	121	36.1185	164	1,561	33,982	1.07	1.12	16.61
Jun-19	30,335	27,056	22,396	4,659	25	36.1185	30	184	27,240	0.89	0.90	16.56
Jul-19	30,289	22,809	22,809	0	1	0.0000	0	0	22,809	0.75	0.75	16.56
Aug-19	30,225	22,813	22,813	0	2	0.0000	16	0	22,813	0.75	0.75	16.65
Sep-19	30,246	21,744	21,744	0	29	0.0000	83	0	21,744	0.72	0.72	16.44
Oct-19	30,239	31,625	22,811	8,814	266	33.1336	350	2,782	34,408	1.05	1.14	16.34
Nov-19	30,375	42,482	22,811	19,671	764	25.7588	672	(2,361)	40,121	1.40	1.32	16.20
Dec-19	30,385	68,199	22,811	45,388	923	49.1716	952	1,424	69,622	2.24	2.29	16.35
Jan-20	30,116	65,048	22,811	42,237	916	46.1294	1,120	9,428	74,476	2.16	2.47	16.56
Feb-20	29,884	48,258	22,811	25,447	822	30.9588	962	4,335	52,593	1.61	1.76	16.13
Mar-20	29,677	39,590	22,811	16,780	595	28.2213	805	5,938	45,529	1.33	1.53	15.99
Apr-20	29,660	44,972	22,811	22,162	488	45.4154	414	(3,360)	41,613	1.52	1.40	16.16
May-20	29,634	30,467	22,811	7,656	217	35.2787	164	(1,871)	28,597	1.03	0.96	16.01
Jun-20	29,649	28,965	22,811	6,154	13	40.3471	30	680	29,645	0.98	1.00	16.11
Jul-20	29,567	25,240	25,240	0	0	0.0000	0	0	25,240	0.85	0.85	16.21
Aug-20	29,526	16,604	16,604	0	0	0.0000	16	0	16,604	0.56	0.56	16.02
Sep-20	29,515	28,532	20,922	7,610	88	43.1991	83	(207)	28,325	0.97	0.96	16.26
Oct-20	29,575	35,644	22,811	12,833	309	41.5321	350	1,703	37,347	1.21	1.26	16.39
Nov-20	29,665	45,558	22,811	22,747	507	44.8662	672	7,403	52,961	1.54	1.79	16.85
Dec-20	29,727	53,512	22,811	30,701	940	32.6606	952	392	53,904	1.80	1.81	16.37
Jan-21	29,320	69,076	22,811	46,265	1,025	45.1366	1,120	4,288	73,364	2.36	2.50	16.40
Feb-21	28,881	55,251	22,811	32,441	969	33.4785	962	(234)	55,017	1.91	1.90	16.55
Mar-21	28,445	52,939	22,811	30,129	649	46.4231	805	7,242	60,181	1.86	2.12	17.13
Apr-21	28,456	33,006	22,811	10,195	388	26.2762	414	683	33,689	1.16	1.18	16.91
May-21	28,414	24,956	22,811	2,146	204	10.5176	164	(421)	24,536	0.88	0.86	16.81
Jun-21	28,311	16,306	16,306	0	12	0.0000	30	0	16,306	0.58	0.58	16.38
Jul-21	28,261	22,655	22,655	0	0	0.0000	0	0	22,655	0.80	0.80	16.33
Aug-21	28,196	22,307	22,307	0	0	0.0000	16	0	22,307	0.79	0.79	16.56
Sep-21	28,152	22,063	22,063	0	53	0.0000	83	0	22,063	0.78	0.78	16.38

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Residential Non-Heating - Rate RT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-03	402	574	362	212	455	0.4647	350	(49)	525	1.43	1.31	
Nov-03	396	739	362	377	574	0.6564	672	64	803	1.87	2.03	
Dec-03	377	847	362	485	999	0.4852	952	(23)	824	2.25	2.19	
Jan-04	370	955	362	593	1,357	0.4368	1,120	(104)	851	2.58	2.30	
Feb-04	368	919	362	556	983	0.5659	962	(12)	907	2.50	2.46	
Mar-04	358	671	362	309	736	0.4194	805	29	700	1.87	1.95	
Apr-04	350	619	362	256	438	0.5854	414	(14)	605	1.77	1.73	
May-04	347	512	362	149	97	0.5024	164	34	545	1.47	1.57	
Jun-04	344	375	362	12	52	0.2377	30	(5)	369	1.09	1.07	
Jul-04	344	342	342	0	1	0.0000	0	0	342	0.99	0.99	
Aug-04	340	383	383	0	21	0.0000	16	0	383	1.13	1.13	
Sep-04	336	314	314	0	59	0.0000	83	0	314	0.93	0.93	19.66
Oct-04	334	484	362	122	416	0.2935	350	(19)	465	1.45	1.39	19.75
Nov-04	332	501	362	139	627	0.2215	672	10	511	1.51	1.54	19.26
Dec-04	324	714	362	351	1,005	0.3496	952	(19)	695	2.20	2.14	19.22
Jan-05	320	732	362	370	1,217	0.3041	1,120	(30)	703	2.29	2.20	19.11
Feb-05	317	678	362	315	939	0.3360	962	8	685	2.14	2.16	18.81
Mar-05	316	668	362	306	942	0.3243	805	(44)	623	2.11	1.97	18.83
Apr-05	314	541	362	179	377	0.4740	414	18	558	1.72	1.78	18.88
May-05	312	465	362	103	268	0.3826	164	(40)	425	1.49	1.36	18.67
Jun-05	312	288	288	0	16	0.0000	30	0	288	0.92	0.92	18.52
Jul-05	305	326	326	0	0	0.0000	0	0	326	1.07	1.07	18.60
Aug-05	300	255	255	0	1	0.0000	16	0	255	0.85	0.85	18.32
Sep-05	299	295	290	5	35	0.1378	83	7	301	0.99	1.01	18.39
Oct-05	298	335	290	45	351	0.1276	350	(0)	335	1.12	1.12	18.12
Nov-05	297	436	290	146	600	0.2440	672	18	454	1.47	1.53	18.11
Dec-05	294	569	290	279	1,121	0.2488	952	(42)	527	1.94	1.79	17.76
Jan-06	293	690	290	400	890	0.4494	1,120	103	793	2.36	2.71	18.27
Feb-06	287	545	290	255	945	0.2700	962	5	550	1.90	1.92	18.02
Mar-06	284	486	290	196	775	0.2532	805	8	494	1.71	1.74	17.79
Apr-06	345	486	290	196	390	0.5026	414	12	498	1.41	1.44	17.46
May-06	381	483	290	193	184	0.3779	164	(8)	476	1.27	1.25	17.34
Jun-06	391	380	290	90	44	0.3779	30	(5)	374	0.97	0.96	17.38
Jul-06	403	481	481	0	1	0.0000	0	0	481	1.19	1.19	17.50
Aug-06	395	290	290	0	5	0.0000	16	0	290	0.73	0.73	17.39
Sep-06	387	367	367	0	123	0.0000	83	0	367	0.95	0.95	17.33
Oct-06	383	476	385	91	428	0.2125	350	(16)	460	1.24	1.20	17.41
Nov-06	377	636	385	250	552	0.4535	672	54	690	1.69	1.83	17.71
Dec-06	374	711	385	325	813	0.4002	952	56	766	1.90	2.05	17.96
Jan-07	369	705	385	320	997	0.3209	1,120	39	745	1.91	2.02	17.27
Feb-07	366	727	385	341	1,178	0.2899	962	(63)	664	1.99	1.81	17.17
Mar-07	358	769	385	383	824	0.4650	805	(9)	760	2.15	2.12	17.56
Apr-07	375	670	385	284	552	0.5153	414	(71)	599	1.79	1.60	17.71
May-07	375	527	385	141	142	0.4901	164	11	537	1.40	1.43	17.89
Jun-07	371	328	328	0	23	0.0000	30	0	328	0.89	0.89	17.82
Jul-07	366	328	328	0	13	0.0000	0	0	328	0.90	0.90	17.52
Aug-07	360	278	278	0	22	0.0000	16	0	278	0.77	0.77	17.56
Sep-07	351	349	303	46	72	0.3659	83	4	353	1.00	1.01	17.62
Oct-07	347	415	303	112	222	0.5038	350	64	479	1.20	1.38	17.80
Nov-07	345	472	303	169	739	0.2279	672	(15)	456	1.37	1.32	17.30
Dec-07	336	719	303	416	1,006	0.4132	952	(22)	697	2.14	2.07	17.32
Jan-08	327	746	303	442	1,051	0.4210	1,120	29	775	2.28	2.37	17.67
Feb-08	318	642	303	338	975	0.3472	962	(4)	637	2.02	2.00	17.86
Mar-08	313	588	303	285	819	0.3480	805	(5)	583	1.88	1.86	17.60
Apr-08	305	455	303	152	371	0.4096	414	18	473	1.49	1.55	17.56
May-08	299	361	303	58	275	0.2114	164	(23)	338	1.21	1.13	17.25

UGI Utilities, Inc. - Gas Division
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Jun-08	292	296	296	0	18	0.0000	30	0	296	1.01	1.01	17.38
Jul-08	290	252	252	0	0	0.0000	0	0	252	0.87	0.87	17.35
Aug-08	289	267	267	0	14	0.0000	16	0	267	0.92	0.92	17.50
Sep-08	287	317	259	57	80	0.7140	83	2	319	1.10	1.11	17.61
Oct-08	362	450	259	191	468	0.4079	350	(48)	402	1.24	1.11	17.34
Nov-08	550	867	259	608	721	0.8425	672	(42)	825	1.58	1.50	17.51
Dec-08	607	1,535	259	1,276	1,016	1.2555	952	(81)	1,455	2.53	2.40	17.84
Jan-09	601	1,528	259	1,268	1,292	0.9813	1,120	(169)	1,358	2.54	2.26	17.73
Feb-09	590	1,426	259	1,167	927	1.2587	962	44	1,470	2.42	2.49	18.22
Mar-09	571	1,175	259	916	774	1.1839	805	37	1,212	2.06	2.12	18.48
Apr-09	561	955	259	696	419	1.6605	414	(9)	947	1.70	1.69	18.61
May-09	549	750	259	491	179	1.4222	164	(22)	728	1.37	1.33	18.81
Jun-09	529	598	259	339	41	1.4222	30	(15)	583	1.13	1.10	18.90
Jul-09	521	549	549	0	15	0.0000	0	0	549	1.05	1.05	19.08
Aug-09	490	529	529	0	16	0.0000	16	0	529	1.08	1.08	19.24
Sep-09	474	501	501	0	118	0.0000	83	0	501	1.06	1.06	19.19
Oct-09	453	698	539	160	440	0.3629	350	(33)	666	1.54	1.47	19.54
Nov-09	464	912	539	373	571	0.6541	672	66	978	1.97	2.11	20.15
Dec-09	453	1,064	539	525	1,055	0.4975	952	(51)	1,012	2.35	2.23	19.99
Jan-10	455	1,353	539	815	1,157	0.7040	1,120	(26)	1,327	2.97	2.92	20.65
Feb-10	460	1,142	539	603	1,014	0.5950	962	(31)	1,111	2.48	2.42	20.57
Mar-10	458	1,092	539	553	627	0.8818	805	157	1,248	2.38	2.73	21.17
Apr-10	459	702	539	163	325	0.5015	414	45	746	1.53	1.63	21.11
May-10	454	641	539	102	153	0.6661	164	7	648	1.41	1.43	21.21
Jun-10	443	519	519	0	25	0.0000	30	0	519	1.17	1.17	21.28
Jul-10	457	452	452	0	4	0.0000	0	0	452	0.99	0.99	21.22
Aug-10	448	435	435	0	7	0.0000	16	0	435	0.97	0.97	21.11
Sep-10	441	484	444	40	67	0.6057	83	10	494	1.10	1.12	21.18
Oct-10	477	674	444	230	383	0.6008	350	(20)	654	1.41	1.37	21.08
Nov-10	490	938	444	494	669	0.7388	672	2	940	1.91	1.92	20.89
Dec-10	510	1,596	444	1,152	1,162	0.9913	952	(208)	1,387	3.13	2.72	21.37
Jan-11	532	1,871	444	1,427	1,251	1.1409	1,120	(149)	1,721	3.52	3.24	21.69
Feb-11	530	1,617	444	1,173	955	1.2280	962	8	1,625	3.05	3.07	22.34
Mar-11	529	1,348	444	905	836	1.0816	805	(34)	1,314	2.55	2.48	22.10
Apr-11	523	1,157	444	713	414	1.7224	414	(0)	1,157	2.21	2.21	22.69
May-11	517	767	444	324	125	1.4020	164	54	822	1.48	1.59	22.85
Jun-11	515	578	444	134	21	1.4020	30	12	590	1.12	1.15	22.82
Jul-11	509	524	524	0	1	0.0000	0	0	524	1.03	1.03	22.86
Aug-11	507	532	532	0	10	0.0000	16	0	532	1.05	1.05	22.94
Sep-11	553	665	528	137	74	1.8589	83	17	682	1.20	1.23	23.05
Oct-11	652	1,115	528	588	400	1.4704	350	(73)	1,042	1.71	1.60	23.28
Nov-11	825	2,011	528	1,483	559	2.6542	672	300	2,311	2.44	2.80	24.16
Dec-11	1,079	3,387	528	2,860	843	3.3921	952	370	3,757	3.14	3.48	24.93
Jan-12	1,290	4,618	528	4,090	1,002	4.0829	1,120	483	5,101	3.58	3.95	25.64
Feb-12	1,358	4,092	528	3,564	814	4.3781	962	648	4,739	3.01	3.49	26.07
Mar-12	1,419	3,732	528	3,205	487	6.5823	805	2,094	5,826	2.63	4.11	27.69
Apr-12	1,512	2,683	528	2,155	437	4.9352	414	(112)	2,571	1.77	1.70	27.18
May-12	1,742	2,664	528	2,137	73	5.7587	164	525	3,190	1.53	1.83	27.42
Jun-12	1,916	2,288	528	1,761	39	5.7587	30	(50)	2,238	1.19	1.17	27.44
Jul-12	1,975	2,074	2,074	0	1	0.0000	0	0	2,074	1.05	1.05	27.46
Aug-12	2,288	2,433	2,433	0	7	0.0000	16	0	2,433	1.06	1.06	27.48
Sep-12	2,420	2,869	2,253	616	110	5.5941	83	(152)	2,718	1.19	1.12	27.37
Oct-12	2,545	4,324	2,253	2,071	335	6.1721	350	90	4,414	1.70	1.73	27.50
Nov-12	2,651	5,989	2,253	3,736	785	4.7618	672	(536)	5,453	2.26	2.06	26.76
Dec-12	2,805	8,730	2,253	6,477	853	7.5889	952	748	9,478	3.11	3.38	26.66
Jan-13	3,018	9,900	2,253	7,646	1,047	7.3034	1,120	534	10,433	3.28	3.46	26.16

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Feb-13	3,046	9,769	2,253	7,515	974	7.7146	962	(94)	9,675	3.21	3.18	25.85
Mar-13	3,093	8,921	2,253	6,667	884	7.5464	805	(593)	8,328	2.88	2.69	24.43
Apr-13	3,124	7,941	2,253	5,688	427	7.6305	414	(97)	7,844	2.54	2.51	25.24
May-13	3,150	4,934	2,253	2,680	178	7.6305	164	(110)	4,824	1.57	1.53	24.94
Jun-13	3,241	3,978	2,253	1,724	21	7.6305	30	69	4,047	1.23	1.25	25.02
Jul-13	3,306	3,488	3,488	0	4	0.0000	0	0	3,488	1.06	1.06	25.03
Aug-13	3,309	3,687	3,687	0	12	0.0000	16	0	3,687	1.11	1.11	25.08
Sep-13	3,395	4,110	3,588	522	143	3.6602	83	(218)	3,891	1.21	1.15	25.10
Oct-13	3,471	5,542	3,588	1,955	327	5.9705	350	135	5,677	1.60	1.64	25.00
Nov-13	3,652	8,274	3,588	4,687	773	6.0643	672	(612)	7,663	2.27	2.10	25.04
Dec-13	3,798	12,682	3,588	9,094	1,012	8.9873	952	(538)	12,143	3.34	3.20	24.86
Jan-14	3,821	15,651	3,588	12,063	1,310	9.2074	1,120	(1,751)	13,900	4.10	3.64	25.04
Feb-14	3,808	14,698	3,588	11,110	1,114	9.9736	962	(1,515)	13,182	3.86	3.46	25.33
Mar-14	3,771	13,353	3,588	9,766	976	10.0022	805	(1,714)	11,639	3.54	3.09	25.72
Apr-14	3,635	8,342	3,588	4,754	467	10.1885	414	(536)	7,806	2.29	2.15	25.36
May-14	3,576	5,915	3,588	2,327	152	15.2650	164	176	6,091	1.65	1.70	25.53
Jun-14	3,527	4,222	3,588	635	14	12.7268	30	209	4,431	1.20	1.26	25.54
Jul-14	3,483	3,480	3,480	0	10	0.0000	0	0	3,480	1.00	1.00	25.48
Aug-14	3,563	3,882	3,882	0	13	0.0000	16	0	3,882	1.09	1.09	25.46
Sep-14	3,597	4,101	3,681	420	98	4.2728	83	(66)	4,036	1.14	1.12	25.43
Oct-14	3,653	5,698	3,681	2,017	303	6.6632	350	315	6,013	1.56	1.65	25.45
Nov-14	3,732	9,331	3,681	5,650	759	7.4448	672	(647)	8,684	2.50	2.33	25.67
Dec-14	3,714	11,823	3,681	8,142	909	8.9548	952	383	12,206	3.18	3.29	25.76
Jan-15	3,782	13,621	3,681	9,940	1,231	8.0758	1,120	(896)	12,726	3.60	3.36	25.49
Feb-15	3,848	13,671	3,681	9,990	1,275	7.8348	962	(2,453)	11,218	3.55	2.92	24.94
Mar-15	3,903	13,752	3,681	10,071	960	10.4912	805	(1,626)	12,126	3.52	3.11	24.96
Apr-15	3,872	8,145	3,681	4,464	403	11.0728	414	120	8,265	2.10	2.13	24.95
May-15	3,907	5,288	3,681	1,607	83	19.4151	164	1,577	6,865	1.35	1.76	25.01
Jun-15	3,903	4,205	3,681	524	32	16.1746	30	(39)	4,166	1.08	1.07	24.82
Jul-15	3,873	4,018	4,018	0	4	0.0000	0	0	4,018	1.04	1.04	24.85
Aug-15	3,833	3,890	3,890	0	6	0.0000	16	0	3,890	1.01	1.01	24.78
Sep-15	3,829	3,948	3,948	0	42	0.0000	83	0	3,948	1.03	1.03	24.69
Oct-15	3,874	5,905	3,954	1,951	378	5.1629	350	(144)	5,761	1.52	1.49	24.53
Nov-15	3,895	8,586	3,954	4,632	508	9.1138	672	1,492	10,078	2.20	2.59	24.79
Dec-15	3,966	9,585	3,954	5,631	625	9.0136	952	2,949	12,535	2.42	3.16	24.66
Jan-16	3,976	12,204	3,954	8,250	1,130	7.3032	1,120	(71)	12,133	3.07	3.05	24.35
Feb-16	3,977	12,463	3,954	8,510	936	9.0941	962	239	12,702	3.13	3.19	24.63
Mar-16	4,006	9,003	3,954	5,049	582	8.6798	805	1,938	10,941	2.25	2.73	24.25
Apr-16	4,027	6,813	3,954	2,859	468	6.1087	414	(330)	6,483	1.69	1.61	23.73
May-16	4,132	5,979	3,954	2,025	221	9.1689	164	(522)	5,458	1.45	1.32	23.29
Jun-16	3,986	4,342	3,954	389	25	7.6388	30	40	4,382	1.09	1.10	23.33
Jul-16	3,964	3,823	3,823	0	2	0.0000	0	0	3,823	0.96	0.96	23.25
Aug-16	3,941	3,547	3,547	0	3	0.0000	16	0	3,547	0.90	0.90	23.14
Sep-16	3,914	3,781	3,685	96	53	1.8266	83	56	3,837	0.97	0.98	23.09
Oct-16	3,905	4,977	3,685	1,292	324	3.9893	350	105	5,081	1.27	1.30	22.90
Nov-16	3,931	6,035	3,685	2,350	589	3.9916	672	332	6,368	1.54	1.62	21.93
Dec-16	3,995	8,095	3,685	4,410	973	4.5345	952	(93)	8,002	2.03	2.00	20.78
Jan-17	3,968	9,696	3,685	6,011	961	6.2549	1,120	995	10,691	2.44	2.69	20.42
Feb-17	3,971	7,566	3,685	3,881	719	5.4009	962	1,315	8,881	1.91	2.24	19.46
Mar-17	3,992	7,681	3,685	3,995	879	4.5430	805	(338)	7,342	1.92	1.84	18.57
Apr-17	3,860	5,865	3,685	2,179	264	8.2517	414	1,237	7,101	1.52	1.84	18.80
May-17	3,885	4,768	3,685	1,083	205	5.2772	164	(218)	4,551	1.23	1.17	18.65
Jun-17	3,882	4,036	3,685	351	33	6.7645	30	(22)	4,014	1.04	1.03	18.58
Jul-17	3,917	3,755	3,755	0	2	0.0000	0	0	3,755	0.96	0.96	18.58
Aug-17	3,952	3,378	3,378	0	19	0.0000	16	0	3,378	0.85	0.85	18.53
Sep-17	3,991	1,854	1,854	0	89	0.0000	83	0	1,854	0.46	0.46	18.02

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Oct-17	4,122	4,667	3,566	1,101	227	4.8403	350	594	5,260	1.13	1.28	17.99
Nov-17	4,151	9,357	3,566	5,790	684	8.4667	672	(101)	9,256	2.25	2.23	18.60
Dec-17	4,330	9,712	3,566	6,145	1,087	5.6512	952	(765)	8,946	2.24	2.07	18.66
Jan-18	4,340	11,682	3,566	8,115	1,156	7.0225	1,120	(250)	11,432	2.69	2.63	18.60
Feb-18	4,191	7,632	3,566	4,065	775	5.2481	962	983	8,615	1.82	2.06	18.42
Mar-18	4,216	7,477	3,566	3,910	905	4.3227	805	(431)	7,046	1.77	1.67	18.26
Apr-18	4,237	6,669	3,566	3,103	573	5.4168	414	(860)	5,809	1.57	1.37	17.79
May-18	4,293	4,555	3,566	988	69	4.8697	164	464	5,019	1.06	1.17	17.79
Jun-18	4,262	4,753	3,566	1,187	29	4.8697	30	6	4,759	1.12	1.12	17.87
Jul-18	4,248	4,909	4,909	0	2	0.0000	0	0	4,909	1.16	1.16	18.06
Aug-18	4,259	1,796	1,796	0	2	0.0000	16	0	1,796	0.42	0.42	17.63
Sep-18	4,311	4,760	3,353	1,407	61	1.8266	83	40	4,799	1.10	1.11	18.28
Oct-18	4,324	6,414	3,353	3,061	370	8.2744	350	(165)	6,249	1.48	1.45	18.45
Nov-18	4,336	7,639	3,353	4,286	773	5.5475	672	(558)	7,081	1.76	1.63	17.85
Dec-18	4,395	9,212	3,353	5,859	886	6.6135	952	437	9,649	2.10	2.20	17.98
Jan-19	4,384	10,402	3,353	7,049	1,146	6.1496	1,120	(161)	10,240	2.37	2.34	17.68
Feb-19	4,236	8,631	3,353	5,278	904	5.8386	962	338	8,969	2.04	2.12	17.75
Mar-19	4,217	7,129	3,353	3,777	826	4.5744	805	(94)	7,035	1.69	1.67	17.74
Apr-19	4,190	5,416	3,353	2,063	319	6.4590	414	611	6,027	1.29	1.44	17.81
May-19	4,168	5,289	3,353	1,936	121	5.5167	164	238	5,527	1.27	1.33	17.97
Jun-19	4,175	4,121	3,353	768	25	5.5167	30	28	4,149	0.99	0.99	17.84
Jul-19	4,149	3,545	3,545	0	1	0.0000	0	0	3,545	0.85	0.85	17.54
Aug-19	4,137	3,623	3,623	0	2	0.0000	16	0	3,623	0.88	0.88	18.00
Sep-19	4,167	3,129	3,129	0	29	0.0000	83	0	3,129	0.75	0.75	17.63
Oct-19	4,172	4,924	3,584	1,341	266	5.0392	350	423	5,348	1.18	1.28	17.47
Nov-19	4,186	6,335	3,584	2,751	764	3.6027	672	(330)	6,005	1.51	1.43	17.27
Dec-19	4,261	9,776	3,584	6,193	923	6.7088	952	194	9,971	2.29	2.34	17.42
Jan-20	4,248	9,198	3,584	5,614	916	6.1317	1,120	1,253	10,451	2.17	2.46	17.54
Feb-20	4,211	6,938	3,584	3,354	822	4.0806	962	571	7,509	1.65	1.78	17.21
Mar-20	4,224	5,578	3,584	1,994	595	3.3537	805	706	6,284	1.32	1.49	17.03
Apr-20	4,264	6,940	3,584	3,356	488	6.8769	414	(509)	6,431	1.63	1.51	17.10
May-20	4,238	4,457	3,584	873	217	4.0224	164	(213)	4,244	1.05	1.00	16.77
Jun-20	4,209	4,611	3,584	1,028	13	5.4496	30	92	4,703	1.10	1.12	16.90
Jul-20	4,156	3,771	3,771	0	0	0.0000	0	0	3,771	0.91	0.91	16.95
Aug-20	4,168	2,792	2,792	0	0	0.0000	16	0	2,792	0.67	0.67	16.74
Sep-20	4,148	4,701	3,282	1,419	88	6.9846	83	(33)	4,668	1.13	1.13	17.12
Oct-20	4,078	5,524	3,282	2,242	309	7.2570	350	298	5,822	1.35	1.43	17.26
Nov-20	4,066	6,685	3,282	3,403	507	6.7121	672	1,108	7,792	1.64	1.92	17.74
Dec-20	4,051	6,865	3,282	3,583	940	3.8119	952	46	6,911	1.69	1.71	17.11
Jan-21	3,987	8,942	3,282	5,660	1,025	5.5224	1,120	525	9,467	2.24	2.37	17.02
Feb-21	3,904	7,250	3,282	3,969	969	4.0957	962	(29)	7,222	1.86	1.85	17.09
Mar-21	3,828	7,028	3,282	3,746	649	5.7720	805	900	7,928	1.84	2.07	17.67
Apr-21	3,799	4,768	3,282	1,487	388	3.8314	414	100	4,868	1.26	1.28	17.45
May-21	3,782	3,588	3,282	306	204	1.5014	164	(60)	3,528	0.95	0.93	17.38
Jun-21	3,738	2,393	2,393	0	12	0.0000	30	0	2,393	0.64	0.64	16.90
Jul-21	3,720	3,281	3,281	0	0	0.0000	0	0	3,281	0.88	0.88	16.88
Aug-21	3,667	3,267	3,267	0	0	0.0000	16	0	3,267	0.89	0.89	17.10
Sep-21	3,640	3,210	3,210	0	53	0.0000	83	0	3,210	0.88	0.88	16.85

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Commercial Heating - Rate NT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	14,029	555,339	255,292	300,048	335	894.3723	350	12,983	568,322	39.59	40.51	
Nov-12	14,016	1,007,356	255,292	752,064	785	958.5755	672	(107,901)	899,454	71.87	64.17	
Dec-12	14,065	1,340,248	255,292	1,084,956	853	1,271.2722	952	125,295	1,465,543	95.29	104.20	
Jan-13	14,031	1,632,204	255,292	1,376,913	1,047	1,315.1922	1,120	96,103	1,728,307	116.33	123.18	
Feb-13	13,980	1,596,834	255,292	1,341,542	974	1,377.0850	962	(16,786)	1,580,047	114.22	113.02	
Mar-13	13,766	1,318,402	255,292	1,063,110	884	1,203.2583	805	(94,487)	1,223,914	95.77	88.91	
Apr-13	13,533	780,053	255,292	524,761	427	1,229.6560	414	(15,684)	764,369	57.64	56.48	
May-13	13,453	374,026	255,292	118,735	178	665.6411	164	(9,569)	364,457	27.80	27.09	
Jun-13	13,337	227,847	227,847	0	21	0.0000	30	0	227,847	17.08	17.08	
Jul-13	13,275	226,406	226,406	0	4	0.0000	0	0	226,406	17.06	17.06	
Aug-13	13,235	254,250	254,250	0	12	0.0000	16	0	254,250	19.21	19.21	
Sep-13	13,141	291,792	240,328	51,464	143	360.7206	83	(21,524)	270,268	22.20	20.57	691.48
Oct-13	13,096	467,030	240,328	226,703	327	692.5134	350	15,677	482,708	35.66	36.86	687.83
Nov-13	13,138	967,949	240,328	727,621	773	941.4501	672	(94,966)	872,982	73.68	66.45	690.10
Dec-13	13,302	1,457,407	240,328	1,217,079	1,012	1,202.8004	952	(72,013)	1,385,394	109.56	104.15	690.05
Jan-14	13,288	1,946,825	240,328	1,706,497	1,310	1,302.5118	1,120	(247,684)	1,699,141	146.51	127.87	694.75
Feb-14	13,303	1,695,729	240,328	1,455,401	1,114	1,306.5219	962	(198,527)	1,497,202	127.47	112.55	694.27
Mar-14	13,233	1,426,751	240,328	1,186,423	976	1,215.1548	805	(208,224)	1,218,528	107.82	92.08	697.44
Apr-14	12,972	684,768	240,328	444,440	467	952.4995	414	(50,105)	634,663	52.79	48.93	689.89
May-14	12,912	372,263	240,328	131,935	152	865.4111	164	9,993	382,255	28.83	29.60	692.40
Jun-14	12,798	244,573	240,328	4,245	14	313.1728	30	5,150	249,723	19.11	19.51	694.83
Jul-14	12,759	228,478	228,478	0	10	0.0000	0	0	228,478	17.91	17.91	695.68
Aug-14	12,760	258,574	258,574	0	13	0.0000	16	0	258,574	20.26	20.26	696.74
Sep-14	12,823	264,628	243,526	21,102	98	214.4501	83	(3,303)	261,325	20.64	20.38	696.55
Oct-14	12,802	424,944	243,526	181,418	303	599.2722	350	28,327	453,271	33.19	35.41	695.10
Nov-14	12,950	961,047	243,526	717,521	759	945.4105	672	(82,205)	878,842	74.21	67.86	696.51
Dec-14	13,162	1,337,572	243,526	1,094,046	909	1,203.2653	952	51,463	1,389,035	101.62	105.53	697.90
Jan-15	13,235	1,762,259	243,526	1,518,733	1,231	1,233.8364	1,120	(136,837)	1,625,423	133.15	122.81	692.84
Feb-15	13,313	1,874,337	243,526	1,630,810	1,275	1,278.9979	962	(400,414)	1,473,922	140.79	110.71	691.01
Mar-15	13,374	1,478,697	243,526	1,235,171	960	1,286.6714	805	(199,401)	1,279,297	110.57	95.66	694.58
Apr-15	13,481	647,651	243,526	404,125	403	1,002.4714	414	10,898	658,549	48.04	48.85	694.50
May-15	13,667	335,680	243,526	92,154	83	1,113.0213	164	90,382	426,062	24.56	31.17	696.07
Jun-15	13,830	238,049	238,049	0	32	0.0000	30	0	238,049	17.21	17.21	693.77
Jul-15	13,907	254,206	254,206	0	4	0.0000	0	0	254,206	18.28	18.28	694.15
Aug-15	13,914	259,293	259,293	0	6	0.0000	16	0	259,293	18.64	18.64	692.52
Sep-15	13,911	261,360	256,749	4,611	42	108.6112	83	4,404	265,764	18.79	19.10	691.24
Oct-15	14,044	516,296	256,749	259,547	378	686.8616	350	(19,145)	497,151	36.76	35.40	691.23
Nov-15	14,184	780,326	256,749	523,576	508	1,030.0646	672	168,627	948,953	55.01	66.90	690.27
Dec-15	14,310	948,517	256,749	691,767	625	1,107.2317	952	362,317	1,310,834	66.28	91.60	676.34
Jan-16	14,330	1,703,468	256,749	1,446,718	1,130	1,280.6137	1,120	(12,431)	1,691,037	118.87	118.01	671.54
Feb-16	14,388	1,578,339	256,749	1,321,589	936	1,412.3768	962	37,117	1,615,456	109.70	112.28	673.10
Mar-16	14,344	990,030	256,749	733,281	582	1,260.5525	805	281,464	1,271,494	69.02	88.64	666.09
Apr-16	14,187	682,548	256,749	425,799	468	909.7187	414	(49,175)	633,373	48.11	44.64	661.88
May-16	14,203	434,048	256,749	177,299	221	802.6713	164	(45,660)	388,387	30.56	27.35	658.05
Jun-16	14,238	285,111	256,749	28,362	25	856.1950	30	4,457	289,568	20.02	20.34	661.18
Jul-16	14,257	246,096	246,096	0	2	0.0000	0	0	246,096	17.26	17.26	660.16
Aug-16	14,219	255,010	255,010	0	3	0.0000	16	0	255,010	17.93	17.93	659.46
Sep-16	14,197	287,999	287,999	0	53	0.0000	83	0	287,999	20.29	20.29	660.64
Oct-16	14,220	462,258	250,553	211,705	324	653.8938	350	17,158	479,416	32.51	33.71	658.96
Nov-16	14,268	818,215	250,553	567,662	589	964.1215	672	80,228	898,442	57.35	62.97	655.02
Dec-16	14,392	1,451,992	250,553	1,201,439	973	1,235.2845	952	(25,448)	1,426,544	100.89	99.12	662.54
Jan-17	14,377	1,657,798	250,553	1,407,246	961	1,464.4508	1,120	232,939	1,890,738	115.31	131.51	676.05
Feb-17	14,345	1,221,791	250,553	971,238	719	1,351.6643	962	329,063	1,550,854	85.17	108.11	671.88
Mar-17	14,353	1,292,707	250,553	1,042,155	879	1,184.9801	805	(88,246)	1,204,462	90.07	83.92	667.15
Apr-17	14,243	638,710	250,553	388,157	264	1,469.6479	414	220,277	858,987	44.84	60.31	682.82
May-17	14,435	415,647	250,553	165,095	205	804.4224	164	(33,169)	382,478	28.79	26.50	681.97

UGI Utilities, Inc. - Gas Division
Commercial Heating - Rate NT

	[1]	[2]	[3] *	[4] = [2] -[3]	[5]	[6] = [4] / [5]	[7]	[8]=([7] -[5])*[6]	[9] = [8] + [2]			
	Number of	Actual	Base	Temp Sensitive	Actual	Temp Sensitive	Normal	Normalized	Total	ACT	NORM	12 MO
Month	Customers	Sales	Load	Load	DD's	Load/DD	DD's	Sales Adj	Normalized Sales	UPC	UPC	ENDED
Jun-17	14,526	299,166	250,553	48,614	33	804.4224	30	(2,634)	296,532	20.60	20.41	682.04
Jul-17	14,725	254,640	254,640	0	2	0.0000	0	0	254,640	17.29	17.29	682.08
Aug-17	14,858	291,050	291,050	0	19	0.0000	16	0	291,050	19.59	19.59	683.73
Sep-17	15,026	170,571	170,571	0	89	0.0000	83	0	170,571	11.35	11.35	674.80
Oct-17	15,183	452,263	272,845	179,419	227	789.0967	350	96,765	549,029	29.79	36.16	677.24
Nov-17	15,247	1,252,072	272,845	979,227	684	1,431.8325	672	(17,036)	1,235,036	82.12	81.00	695.28
Dec-17	15,463	1,577,649	272,845	1,304,804	1,087	1,199.9114	952	(162,488)	1,415,160	102.03	91.52	687.67
Jan-18	15,672	2,010,551	272,845	1,737,706	1,156	1,503.6896	1,120	(53,574)	1,956,977	128.29	124.87	681.03
Feb-18	15,703	1,374,896	272,845	1,102,051	775	1,422.6714	962	266,558	1,641,455	87.56	104.53	677.45
Mar-18	15,825	1,519,857	272,845	1,247,012	905	1,378.4815	805	(137,334)	1,382,522	96.04	87.36	680.90
Apr-18	15,915	1,000,743	272,845	727,898	573	1,270.8191	414	(201,779)	798,964	62.88	50.20	670.79
May-18	16,016	343,691	272,845	70,846	69	1,032.3844	164	98,465	442,156	21.46	27.61	671.90
Jun-18	15,919	340,863	272,845	68,018	29	1,151.6018	30	1,396	342,258	21.41	21.50	672.99
Jul-18	15,946	276,058	276,058	0	2	0.0000	0	0	276,058	17.31	17.31	673.01
Aug-18	16,104	280,747	280,747	0	2	0.0000	16	0	280,747	17.43	17.43	670.85
Sep-18	16,173	335,717	278,403	57,315	61	935.8746	83	20,363	356,080	20.76	22.02	681.52
Oct-18	16,298	676,964	278,403	398,561	370	1,077.2780	350	(21,514)	655,450	41.54	40.22	685.57
Nov-18	16,446	1,276,687	278,403	998,284	773	1,292.1195	672	(129,980)	1,146,707	77.63	69.73	674.30
Dec-18	16,644	1,611,170	278,403	1,332,768	886	1,504.2807	952	99,308	1,710,478	96.80	102.77	685.55
Jan-19	16,669	2,111,521	278,403	1,833,118	1,146	1,599.2652	1,120	(41,941)	2,069,580	126.67	124.16	684.83
Feb-19	16,647	1,695,455	278,403	1,417,052	904	1,567.4386	962	90,824	1,786,278	101.85	107.30	687.61
Mar-19	16,628	1,531,896	278,403	1,253,493	826	1,518.2802	805	(31,278)	1,500,618	92.13	90.25	690.49
Apr-19	16,627	684,167	278,403	405,765	319	1,270.4618	414	120,207	804,374	41.15	48.38	688.66
May-19	16,539	484,130	278,403	205,728	121	1,703.1368	164	73,587	557,717	29.27	33.72	694.78
Jun-19	16,501	318,632	278,403	40,230	25	1,615.6824	30	8,241	326,873	19.31	19.81	693.09
Jul-19	16,505	302,782	302,782	0	1	0.0000	0	0	302,782	18.34	18.34	694.12
Aug-19	16,490	319,149	319,149	0	2	0.0000	16	0	319,149	19.35	19.35	696.04
Sep-19	16,570	280,386	280,386	0	29	0.0000	83	0	280,386	16.92	16.92	690.95
Oct-19	16,610	544,421	310,966	233,456	266	877.5757	350	73,696	618,117	32.78	37.21	687.94
Nov-19	16,664	1,517,735	310,966	1,206,769	764	1,580.2416	672	(144,847)	1,372,888	91.08	82.39	700.60
Dec-19	16,708	1,369,299	310,966	1,058,334	923	1,146.5613	952	33,193	1,402,492	81.95	83.94	681.78
Jan-20	16,792	1,868,141	310,966	1,557,175	916	1,700.6631	1,120	347,568	2,215,708	111.25	131.95	689.57
Feb-20	16,821	1,592,686	310,966	1,281,720	822	1,559.3411	962	218,366	1,811,052	94.68	107.67	689.93
Mar-20	16,943	1,122,304	310,966	811,338	595	1,364.5666	805	287,138	1,409,442	66.24	83.19	682.87
Apr-20	17,024	898,888	310,966	587,923	488	1,204.8180	414	(89,128)	809,760	52.80	47.57	682.06
May-20	17,007	433,040	310,966	122,075	217	562.4942	164	(29,825)	403,215	25.46	23.71	672.05
Jun-20	16,958	302,919	302,919	0	13	0.0000	30	0	302,919	17.86	17.86	670.10
Jul-20	16,911	287,260	287,260	0	0	0.0000	0	0	287,260	16.99	16.99	668.74
Aug-20	16,930	254,132	254,132	0	0	0.0000	16	0	254,132	15.01	15.01	664.40
Sep-20	16,888	347,957	270,696	77,260	88	880.0129	83	(4,219)	343,737	20.60	20.35	667.83
Oct-20	16,859	535,817	270,696	265,121	309	857.9961	350	35,178	570,995	31.78	33.87	664.49
Nov-20	16,870	1,082,511	270,696	811,814	507	1,601.2112	672	264,200	1,346,710	64.17	79.83	661.93
Dec-20	16,858	1,566,846	270,696	1,296,149	940	1,378.8822	952	16,547	1,583,392	92.94	93.93	671.92
Jan-21	16,865	1,981,181	270,696	1,710,485	1,025	1,668.7659	1,120	158,533	2,139,714	117.47	126.87	666.84
Feb-21	16,859	1,874,163	270,696	1,603,466	969	1,654.7642	962	(11,583)	1,862,580	111.17	110.48	669.65
Mar-21	16,781	1,271,146	270,696	1,000,449	649	1,541.5244	805	240,478	1,511,624	75.75	90.08	676.54
Apr-21	16,746	788,645	270,696	517,949	388	1,334.9193	414	34,708	823,353	47.09	49.17	678.15
May-21	16,726	495,878	270,696	225,181	204	1,103.8290	164	(44,153)	451,724	29.65	27.01	681.44
Jun-21	16,771	292,860	270,696	22,164	12	1,219.3741	30	21,949	314,809	17.46	18.77	682.35
Jul-21	16,811	313,066	313,066	0	0	0.0000	0	0	313,066	18.62	18.62	683.99
Aug-21	16,830	331,675	331,675	0	0	0.0000	16	0	331,675	19.71	19.71	688.68
Sep-21	16,856	337,082	302,963	34,119	53	643.7470	83	19,312	356,394	20.00	21.14	689.47

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Divison
Commercial Heating - Rate DS

	[1] Number of Customers	[2] Budget Sales	[3] Budget UPC
Oct-22	1,166	389,543	334.1
Nov-22	1,166	674,801	578.7
Dec-22	1,166	1,065,548	913.8
Jan-23	1,166	1,384,646	1,187.5
Feb-23	1,166	1,232,849	1,057.3
Mar-23	1,166	1,019,308	874.2
Apr-23	1,166	573,452	491.8
May-23	1,166	334,136	286.6
Jun-23	1,166	229,633	196.9
Jul-23	1,166	195,983	168.1
Aug-23	1,166	197,375	169.3
Sep-23	1,166	244,301	209.5
Total			6,467.9

UGI Utilities, Inc. - Gas Division
Commercial Non-Heating - Combined Rate N, NT, and DS

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	5,028	125,624	90,835	34,789	335	103.6981	350	1,505	127,129	24.98	25.28	
Nov-12	5,016	142,209	90,835	51,374	785	65.4815	672	(7,371)	134,839	28.35	26.88	
Dec-12	4,997	175,274	90,835	84,439	853	98.9392	952	9,751	185,025	35.08	37.03	
Jan-13	4,979	172,405	90,835	81,570	1,047	77.9135	1,120	5,693	178,098	34.63	35.77	
Feb-13	4,970	169,996	90,835	79,161	974	81.2586	962	(991)	169,006	34.20	34.01	
Mar-13	4,960	173,112	90,835	82,277	884	93.1235	805	(7,313)	165,799	34.90	33.43	
Apr-13	4,949	137,501	90,835	46,666	427	87.1910	414	(1,112)	136,389	27.78	27.56	
May-13	4,936	104,981	90,835	14,146	178	79.3056	164	(1,140)	103,841	21.27	21.04	
Jun-13	4,921	90,544	90,544	0	21	0.0000	30	0	90,544	18.40	18.40	
Jul-13	4,921	89,667	89,667	0	4	0.0000	0	0	89,667	18.22	18.22	
Aug-13	4,904	93,665	93,665	0	12	0.0000	16	0	93,665	19.10	19.10	
Sep-13	4,904	102,720	91,666	11,054	143	77.4813	83	(4,623)	98,097	20.95	20.00	316.72
Oct-13	4,905	119,401	91,666	27,735	327	84.7226	350	1,918	121,319	24.34	24.73	316.17
Nov-13	4,916	143,784	91,666	52,118	773	67.4336	672	(6,802)	136,982	29.25	27.86	317.15
Dec-13	4,914	176,792	91,666	85,126	1,012	84.1276	952	(5,037)	171,756	35.98	34.95	315.07
Jan-14	4,904	199,516	91,666	107,850	1,310	82.3182	1,120	(15,654)	183,863	40.68	37.49	316.80
Feb-14	4,900	188,798	91,666	97,132	1,114	87.1959	962	(13,249)	175,549	38.53	35.83	318.62
Mar-14	4,888	189,680	91,666	98,014	976	100.3873	805	(17,202)	172,478	38.81	35.29	320.48
Apr-14	4,886	130,911	91,666	39,245	467	84.1076	414	(4,424)	126,487	26.79	25.89	318.80
May-14	4,859	107,466	91,666	15,800	152	92.2475	164	1,065	108,531	22.12	22.34	320.10
Jun-14	4,858	93,200	91,666	1,534	14	88.1776	30	1,450	94,651	19.18	19.48	321.19
Jul-14	4,842	90,876	90,876	0	10	0.0000	0	0	90,876	18.77	18.77	321.73
Aug-14	4,831	95,470	95,470	0	13	0.0000	16	0	95,470	19.76	19.76	322.40
Sep-14	4,830	97,680	93,173	4,508	98	45.8101	83	(706)	96,975	20.22	20.08	322.47
Oct-14	4,832	117,193	93,173	24,020	303	79.3453	350	3,751	120,943	24.25	25.03	322.77
Nov-14	4,829	149,588	93,173	56,415	759	74.3327	672	(6,463)	143,124	30.98	29.64	324.54
Dec-14	4,803	180,296	93,173	87,123	909	95.8207	952	4,098	184,394	37.54	38.39	327.98
Jan-15	4,801	191,797	93,173	98,624	1,231	80.1236	1,120	(8,886)	182,911	39.95	38.10	328.59
Feb-15	4,799	193,847	93,173	100,674	1,275	78.9558	962	(24,719)	169,128	40.39	35.24	328.00
Mar-15	4,798	198,110	93,173	104,937	960	109.3124	805	(16,941)	181,169	41.29	37.76	330.47
Apr-15	4,791	131,510	93,173	38,338	403	95.1008	414	1,034	132,544	27.45	27.67	332.25
May-15	4,785	100,831	93,173	7,658	83	92.4941	164	7,511	108,342	21.07	22.64	332.56
Jun-15	4,776	91,956	91,956	0	32	0.0000	30	0	91,956	19.25	19.25	332.33
Jul-15	4,768	93,264	93,264	0	4	0.0000	0	0	93,264	19.56	19.56	333.12
Aug-15	4,768	92,746	92,746	0	6	0.0000	16	0	92,746	19.45	19.45	332.81
Sep-15	4,771	95,852	93,005	2,848	42	67.0802	83	2,720	98,572	20.09	20.66	333.39
Oct-15	4,774	122,076	93,005	29,072	378	76.9353	350	(2,144)	119,932	25.57	25.12	333.49
Nov-15	4,771	139,795	93,005	46,790	508	92.0528	672	15,070	154,864	29.30	32.46	336.31
Dec-15	4,775	140,288	93,005	47,283	625	75.6803	952	24,765	165,052	29.38	34.57	332.48
Jan-16	4,770	176,885	93,005	83,880	1,130	74.2495	1,120	(721)	176,164	37.08	36.93	331.31
Feb-16	4,771	187,001	93,005	93,996	936	100.4530	962	2,640	189,641	39.20	39.75	335.82
Mar-16	4,763	138,663	93,005	45,658	582	78.4887	805	17,525	156,188	29.11	32.79	330.85
Apr-16	4,762	117,978	93,005	24,973	468	53.3552	414	(2,884)	115,094	24.77	24.17	327.36
May-16	4,760	114,885	93,005	21,880	221	99.0570	164	(5,635)	109,250	24.14	22.95	327.67
Jun-16	4,750	117,085	93,005	24,080	25	76.2061	30	397	117,482	24.65	24.73	333.15
Jul-16	4,755	104,757	93,005	11,752	2	76.2061	0	(144)	104,613	22.03	22.00	335.59
Aug-16	4,746	71,191	71,191	0	3	0.0000	16	0	71,191	15.00	15.00	331.13
Sep-16	4,759	78,998	78,998	0	53	0.0000	83	0	78,998	16.60	16.60	327.07
Oct-16	4,769	107,476	75,094	32,382	324	100.0181	350	2,624	110,101	22.54	23.09	325.04
Nov-16	4,752	128,627	75,094	53,533	589	90.9214	672	7,566	136,193	27.07	28.66	321.24
Dec-16	4,747	177,809	75,094	102,715	973	105.6088	952	(2,176)	175,634	37.46	37.00	323.67
Jan-17	4,753	193,453	75,094	118,359	961	123.1704	1,120	19,592	213,045	40.70	44.82	331.56
Feb-17	4,745	154,289	75,094	79,195	719	110.2152	962	26,832	181,121	32.52	38.17	329.99
Mar-17	4,749	145,571	75,094	70,477	879	80.1357	805	(5,968)	139,603	30.65	29.40	326.59
Apr-17	4,759	146,029	75,094	70,935	264	95.1755	414	14,265	160,294	30.68	33.68	336.10
May-17	4,770	91,694	75,094	16,599	205	80.8805	164	(3,335)	88,359	19.22	18.52	331.68

UGI Utilities, Inc. - Gas Division
Commercial Non-Heating - Combined Rate N, NT, and DS

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Jun-17	4,762	95,461	75,094	20,367	33	88.0280	30	(288)	95,173	20.05	19.99	326.93
Jul-17	4,761	85,606	85,606	0	2	0.0000	0	0	85,606	17.98	17.98	322.91
Aug-17	4,759	86,301	86,301	0	19	0.0000	16	0	86,301	18.13	18.13	326.04
Sep-17	4,753	77,568	77,568	0	89	0.0000	83	0	77,568	16.32	16.32	325.76
Oct-17	4,771	111,955	85,954	26,001	227	114.3542	350	14,023	125,978	23.47	26.40	329.08
Nov-17	4,770	169,230	85,954	83,276	684	121.7668	672	(1,449)	167,781	35.48	35.17	335.60
Dec-17	4,776	167,421	85,954	81,467	1,087	74.9178	952	(10,145)	157,276	35.05	32.93	331.53
Jan-18	4,787	232,056	85,954	146,102	1,156	126.4268	1,120	(4,504)	227,552	48.48	47.54	334.24
Feb-18	4,787	172,808	85,954	86,854	775	112.1221	962	21,008	193,815	36.10	40.49	336.56
Mar-18	4,776	172,068	85,954	86,114	905	95.1933	805	(9,484)	162,584	36.03	34.04	341.20
Apr-18	4,773	136,871	85,954	50,917	573	88.8943	414	(14,115)	122,756	28.68	25.72	333.24
May-18	4,775	102,347	85,954	16,393	69	92.0438	164	8,779	111,125	21.43	23.27	337.99
Jun-18	4,756	101,001	85,954	15,048	29	92.0438	30	112	101,113	21.24	21.26	339.26
Jul-18	4,742	87,527	87,527	0	2	0.0000	0	0	87,527	18.46	18.46	339.74
Aug-18	4,739	92,099	92,099	0	2	0.0000	16	0	92,099	19.43	19.43	341.04
Sep-18	4,759	102,184	89,813	12,371	61	107.1862	83	2,332	104,516	21.47	21.96	346.68
Oct-18	4,771	124,350	89,813	34,537	370	93.3508	350	(1,864)	122,486	26.06	25.67	345.95
Nov-18	4,783	184,227	89,813	94,414	773	122.2037	672	(12,293)	171,934	38.52	35.95	346.72
Dec-18	4,793	194,415	89,813	104,602	886	118.0634	952	7,794	202,209	40.56	42.19	355.98
Jan-19	4,790	218,988	89,813	129,175	1,146	112.6957	1,120	(2,955)	216,032	45.72	45.10	353.54
Feb-19	4,774	194,184	89,813	104,371	904	115.4479	962	6,690	200,874	40.68	42.08	355.13
Mar-19	4,759	192,090	89,813	102,277	826	123.8815	805	(2,552)	189,538	40.36	39.83	360.92
Apr-19	4,749	120,579	89,813	30,766	319	96.3278	414	9,114	129,693	25.39	27.31	362.51
May-19	4,779	113,153	89,813	23,340	121	110.1047	164	4,757	117,910	23.68	24.67	363.91
Jun-19	4,781	107,559	89,813	17,746	25	103.2162	30	526	108,086	22.50	22.61	365.26
Jul-19	4,775	88,301	88,301	0	1	0.0000	0	0	88,301	18.49	18.49	365.29
Aug-19	4,783	90,059	90,059	0	2	0.0000	16	0	90,059	18.83	18.83	364.69
Sep-19	4,789	94,658	89,180	5,478	29	107.1862	83	5,793	100,451	19.77	20.98	363.70
Oct-19	4,794	119,168	89,180	29,988	266	112.7256	350	9,466	128,634	24.86	26.83	364.86
Nov-19	4,793	143,068	89,180	53,888	764	70.5660	672	(6,468)	136,600	29.85	28.50	357.41
Dec-19	4,796	191,088	89,180	101,908	923	110.4034	952	3,196	194,284	39.84	40.51	355.73
Jan-20	4,796	207,501	89,180	118,321	916	129.2235	1,120	26,410	233,910	43.27	48.77	359.40
Feb-20	4,788	206,272	89,180	117,092	822	142.4543	962	19,949	226,221	43.08	47.25	364.57
Mar-20	4,787	173,813	89,180	84,633	595	142.3418	805	29,952	203,765	36.31	42.57	367.31
Apr-20	4,789	105,855	89,180	16,675	488	34.1712	414	(2,528)	103,327	22.10	21.58	361.58
May-20	4,783	83,268	83,268	0	217	0.0000	164	0	83,268	17.41	17.41	354.32
Jun-20	4,784	88,676	88,676	0	13	0.0000	30	0	88,676	18.54	18.54	350.25
Jul-20	4,773	80,070	80,070	0	0	0.0000	0	0	80,070	16.78	16.78	348.53
Aug-20	4,767	81,405	81,405	0	0	0.0000	16	0	81,405	17.08	17.08	346.78
Sep-20	4,759	66,348	66,348	0	88	0.0000	83	0	66,348	13.94	13.94	339.74
Oct-20	4,766	118,307	80,737	37,569	309	121.5835	350	4,985	123,292	24.82	25.87	338.78
Nov-20	4,763	145,591	80,737	64,854	507	127.9169	672	21,106	166,697	30.57	35.00	345.28
Dec-20	4,748	154,249	80,737	73,512	940	78.2038	952	938	155,187	32.49	32.68	337.45
Jan-21	4,752	191,977	80,737	111,239	1,025	108.5263	1,120	10,310	202,287	40.40	42.57	331.25
Feb-21	4,750	177,209	80,737	96,472	969	99.5581	962	(697)	176,512	37.31	37.16	321.16
Mar-21	4,742	158,886	80,737	78,149	649	120.4147	805	18,785	177,671	33.51	37.47	316.06
Apr-21	4,744	118,690	80,737	37,953	388	97.8161	414	2,543	121,233	25.02	25.56	320.04
May-21	4,741	92,611	80,737	11,874	204	58.2055	164	(2,328)	90,283	19.53	19.04	321.68
Jun-21	4,733	71,464	71,464	0	12	0.0000	30	0	71,464	15.10	15.10	318.24
Jul-21	4,722	84,133	84,133	0	0	0.0000	0	0	84,133	17.82	17.82	319.28
Aug-21	4,719	94,589	94,589	0	0	0.0000	16	0	94,589	20.04	20.04	322.25
Sep-21	4,716	91,910	89,361	2,549	53	48.1012	83	1,443	93,353	19.49	19.80	328.10

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Commercial Non-Heating - Rate NT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	1,233	51,212	36,787	14,425	335	42.9985	350	624	51,836	41.53	42.04	
Nov-12	1,235	60,725	36,787	23,938	785	30.5112	672	(3,434)	57,290	49.17	46.39	
Dec-12	1,255	70,122	36,787	33,336	853	39.0604	952	3,850	73,972	55.87	58.94	
Jan-13	1,241	67,680	36,787	30,893	1,047	29.5081	1,120	2,156	69,836	54.54	56.27	
Feb-13	1,238	70,601	36,787	33,814	974	34.7098	962	(423)	70,177	57.03	56.69	
Mar-13	1,225	68,421	36,787	31,634	884	35.8043	805	(2,812)	65,609	55.85	53.56	
Apr-13	1,210	59,892	36,787	23,105	427	54.1411	414	(691)	59,201	49.50	48.93	
May-13	1,206	42,895	36,787	6,108	178	34.2422	164	(492)	42,402	35.57	35.16	
Jun-13	1,198	37,181	36,787	394	21	18.7913	30	170	37,350	31.04	31.18	
Jul-13	1,190	35,626	35,626	0	4	0.0000	0	0	35,626	29.94	29.94	
Aug-13	1,185	37,822	37,822	0	12	0.0000	16	0	37,822	31.92	31.92	
Sep-13	1,186	40,441	36,724	3,717	143	26.0565	83	(1,555)	38,886	34.10	32.79	523.80
Oct-13	1,190	48,920	36,724	12,196	327	37.2545	350	843	49,763	41.11	41.82	523.57
Nov-13	1,193	60,609	36,724	23,885	773	30.9038	672	(3,117)	57,491	50.80	48.19	525.37
Dec-13	1,216	70,999	36,724	34,275	1,012	33.8733	952	(2,028)	68,971	58.39	56.72	523.15
Jan-14	1,194	74,801	36,724	38,077	1,310	29.0631	1,120	(5,527)	69,274	62.65	58.02	524.90
Feb-14	1,194	75,635	36,724	38,911	1,114	34.9308	962	(5,308)	70,327	63.35	58.90	527.11
Mar-14	1,184	73,876	36,724	37,152	976	38.0518	805	(6,520)	67,355	62.40	56.89	530.44
Apr-14	1,162	52,991	36,724	16,267	467	34.8631	414	(1,834)	51,157	45.60	44.03	525.54
May-14	1,156	44,902	36,724	8,178	152	36.4575	164	421	45,323	38.84	39.21	529.59
Jun-14	1,159	36,574	36,574	0	14	0.0000	30	0	36,574	31.56	31.56	529.97
Jul-14	1,165	35,435	35,435	0	10	0.0000	0	0	35,435	30.42	30.42	530.44
Aug-14	1,166	38,234	38,234	0	13	0.0000	16	0	38,234	32.79	32.79	531.32
Sep-14	1,167	37,897	36,834	1,062	98	10.7965	83	(166)	37,730	32.47	32.33	530.86
Oct-14	1,159	48,477	36,834	11,642	303	38.4572	350	1,818	50,294	41.83	43.39	532.44
Nov-14	1,185	65,349	36,834	28,515	759	37.5717	672	(3,267)	62,083	55.15	52.39	536.64
Dec-14	1,202	70,872	36,834	34,037	909	37.4354	952	1,601	72,473	58.96	60.29	540.21
Jan-15	1,197	74,413	36,834	37,578	1,231	30.5291	1,120	(3,386)	71,027	62.17	59.34	541.53
Feb-15	1,195	77,627	36,834	40,793	1,275	31.9926	962	(10,016)	67,611	64.96	56.58	539.21
Mar-15	1,194	83,165	36,834	46,331	960	48.2629	805	(7,479)	75,686	69.65	63.39	545.71
Apr-15	1,204	56,249	36,834	19,415	403	48.1605	414	524	56,773	46.72	47.15	548.84
May-15	1,219	42,800	36,834	5,966	83	48.2117	164	3,915	46,715	35.11	38.32	547.95
Jun-15	1,228	38,418	36,834	1,584	32	48.8594	30	(118)	38,300	31.29	31.19	547.59
Jul-15	1,229	39,789	39,789	0	4	0.0000	0	0	39,789	32.38	32.38	549.55
Aug-15	1,237	39,697	39,697	0	6	0.0000	16	0	39,697	32.09	32.09	548.85
Sep-15	1,234	39,943	39,743	200	42	4.7066	83	191	40,134	32.37	32.52	549.04
Oct-15	1,255	55,563	39,743	15,820	378	41.8646	350	(1,167)	54,396	44.27	43.34	548.99
Nov-15	1,262	62,109	39,743	22,366	508	44.0017	672	7,203	69,312	49.21	54.92	551.52
Dec-15	1,258	61,707	39,743	21,963	625	35.1542	952	11,503	73,210	49.05	58.20	549.42
Jan-16	1,256	70,579	39,743	30,835	1,130	27.2950	1,120	(265)	70,314	56.19	55.98	546.07
Feb-16	1,259	78,454	39,743	38,711	936	41.3704	962	1,087	79,542	62.31	63.18	552.67
Mar-16	1,255	61,323	39,743	21,580	582	37.0974	805	8,283	69,607	48.86	55.46	544.74
Apr-16	1,246	51,989	39,743	12,246	468	26.1635	414	(1,414)	50,575	41.72	40.59	538.18
May-16	1,247	48,700	39,743	8,957	221	40.5515	164	(2,307)	46,394	39.05	37.20	537.06
Jun-16	1,245	39,598	39,598	0	25	0.0000	30	0	39,598	31.81	31.81	537.68
Jul-16	1,240	38,088	38,088	0	2	0.0000	0	0	38,088	30.72	30.72	536.02
Aug-16	1,250	37,894	37,894	0	3	0.0000	16	0	37,894	30.32	30.32	534.24
Sep-16	1,249	40,329	40,329	0	53	0.0000	83	0	40,329	32.29	32.29	534.01
Oct-16	1,255	48,978	37,991	10,987	324	33.9344	350	890	49,868	39.03	39.74	530.40
Nov-16	1,247	57,277	37,991	19,286	589	32.7560	672	2,726	60,003	45.93	48.12	523.59
Dec-16	1,260	71,745	37,991	33,754	973	34.7050	952	(715)	71,030	56.94	56.37	521.77
Jan-17	1,253	82,460	37,991	44,469	961	46.2767	1,120	7,361	89,821	65.81	71.68	537.47
Feb-17	1,254	66,372	37,991	28,380	719	39.4968	962	9,616	75,987	52.93	60.60	534.89
Mar-17	1,254	65,110	37,991	27,119	879	30.8352	805	(2,296)	62,813	51.92	50.09	529.52
Apr-17	1,250	55,001	37,991	17,010	264	35.1660	414	5,271	60,272	44.00	48.22	537.15
May-17	1,268	43,410	37,991	5,419	205	26.4033	164	(1,089)	42,321	34.23	33.38	533.32

UGI Utilities, Inc. - Gas Division
Commercial Non-Heating - Rate NT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Jun-17	1,281	38,552	37,991	561	33	16.8656	30	(55)	38,497	30.10	30.05	531.57
Jul-17	1,293	36,292	36,292	0	2	0.0000	0	0	36,292	28.07	28.07	528.92
Aug-17	1,308	39,317	39,317	0	19	0.0000	16	0	39,317	30.06	30.06	528.66
Sep-17	1,325	40,723	37,805	2,919	89	32.6507	83	(209)	40,515	30.73	30.58	526.95
Oct-17	1,343	32,791	32,791	0	227	0.0000	350	0	32,791	24.42	24.42	511.63
Nov-17	1,353	79,222	37,805	41,417	684	60.5600	672	(721)	78,501	58.55	58.02	521.53
Dec-17	1,381	72,035	37,805	34,230	1,087	31.4786	952	(4,263)	67,772	52.16	49.07	514.23
Jan-18	1,391	109,373	37,805	71,568	1,156	61.9302	1,120	(2,206)	107,167	78.63	77.04	519.59
Feb-18	1,401	75,487	37,805	37,682	775	48.6452	962	9,114	84,601	53.88	60.39	519.38
Mar-18	1,408	70,652	37,805	32,848	905	36.3108	805	(3,618)	67,035	50.18	47.61	516.90
Apr-18	1,419	61,634	37,805	23,830	573	41.6036	414	(6,606)	55,029	43.44	38.78	507.46
May-18	1,417	44,166	37,805	6,362	69	38.9572	164	3,716	47,882	31.17	33.79	507.88
Jun-18	1,407	42,003	37,805	4,199	29	38.9572	30	47	42,051	29.85	29.89	507.71
Jul-18	1,404	37,331	37,331	0	2	0.0000	0	0	37,331	26.59	26.59	506.23
Aug-18	1,401	36,187	36,187	0	2	0.0000	16	0	36,187	25.83	25.83	502.00
Sep-18	1,417	40,600	36,759	3,841	61	32.6507	83	710	41,310	28.65	29.15	500.58
Oct-18	1,422	43,279	36,759	6,520	370	17.6220	350	(352)	42,927	30.44	30.19	506.35
Nov-18	1,418	91,635	36,759	54,876	773	71.0277	672	(7,145)	84,490	64.62	59.58	507.92
Dec-18	1,433	85,416	36,759	48,657	886	54.9184	952	3,626	89,042	59.61	62.14	520.98
Jan-19	1,427	89,932	36,759	53,172	1,146	46.3891	1,120	(1,217)	88,715	63.02	62.17	506.10
Feb-19	1,422	76,859	36,759	40,100	904	44.3555	962	2,570	79,429	54.05	55.86	501.57
Mar-19	1,405	79,213	36,759	42,453	826	51.4211	805	(1,059)	78,153	56.38	55.63	509.59
Apr-19	1,399	51,929	36,759	15,170	319	47.4979	414	4,494	56,423	37.12	40.33	511.14
May-19	1,424	52,875	36,759	16,116	121	49.4595	164	2,137	55,012	37.13	38.63	515.98
Jun-19	1,421	41,721	36,759	4,961	25	48.4787	30	247	41,968	29.36	29.53	515.63
Jul-19	1,405	39,773	39,773	0	1	0.0000	0	0	39,773	28.31	28.31	517.35
Aug-19	1,411	40,109	40,109	0	2	0.0000	16	0	40,109	28.43	28.43	519.94
Sep-19	1,421	39,038	39,038	0	29	0.0000	83	0	39,038	27.47	27.47	518.26
Oct-19	1,421	51,286	39,406	11,881	266	44.6602	350	3,750	55,037	36.09	38.73	526.81
Nov-19	1,420	63,352	39,406	23,946	764	31.3574	672	(2,874)	60,478	44.61	42.59	509.81
Dec-19	1,420	75,615	39,406	36,209	923	39.2273	952	1,136	76,750	53.25	54.05	501.73
Jan-20	1,421	80,725	39,406	41,319	916	45.1264	1,120	9,223	89,947	56.81	63.30	502.86
Feb-20	1,419	75,951	39,406	36,546	822	44.4614	962	6,226	82,178	53.52	57.91	504.91
Mar-20	1,419	78,650	39,406	39,245	595	66.0045	805	13,889	92,539	55.43	65.21	514.50
Apr-20	1,424	50,274	39,406	10,868	488	22.2721	414	(1,648)	48,626	35.30	34.15	508.32
May-20	1,416	33,078	33,078	0	217	0.0000	164	0	33,078	23.36	23.36	493.05
Jun-20	1,410	37,014	37,014	0	13	0.0000	30	0	37,014	26.25	26.25	489.76
Jul-20	1,422	32,973	32,973	0	0	0.0000	0	0	32,973	23.19	23.19	484.64
Aug-20	1,424	33,755	33,755	0	0	0.0000	16	0	33,755	23.70	23.70	479.92
Sep-20	1,425	37,000	33,364	3,636	88	41.4100	83	(199)	36,801	25.96	25.83	478.27
Oct-20	1,428	52,897	33,364	19,533	309	63.2131	350	2,592	55,489	37.04	38.86	478.40
Nov-20	1,430	63,867	33,364	30,503	507	60.1636	672	9,927	73,794	44.66	51.60	487.41
Dec-20	1,419	64,977	33,364	31,613	940	33.6307	952	404	65,381	45.79	46.08	479.44
Jan-21	1,425	89,784	33,364	56,420	1,025	55.0440	1,120	5,229	95,013	63.01	66.68	482.82
Feb-21	1,422	82,923	33,364	49,559	969	51.1445	962	(358)	82,565	58.31	58.06	482.97
Mar-21	1,417	68,642	33,364	35,278	649	54.3579	805	8,480	77,122	48.44	54.43	472.18
Apr-21	1,415	52,808	33,364	19,444	388	50.1133	414	1,303	54,111	37.32	38.24	476.27
May-21	1,411	41,445	33,364	8,080	204	39.6097	164	(1,584)	39,860	29.37	28.25	481.16
Jun-21	1,408	31,174	31,174	0	12	0.0000	30	0	31,174	22.14	22.14	477.05
Jul-21	1,407	37,571	37,571	0	0	0.0000	0	0	37,571	26.70	26.70	480.57
Aug-21	1,393	42,007	42,007	0	0	0.0000	16	0	42,007	30.16	30.16	487.02
Sep-21	1,393	41,562	34,372	7,190	53	44.8615	83	1,346	42,908	29.84	30.80	491.99

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Commercial Non-Heating-Rate DS

	[1] Number of Customers	[2] Budget Sales	[3] Budget UPC
Oct-22	24	10,965	456.9
Nov-22	24	11,891	495.4
Dec-22	24	14,966	623.6
Jan-23	24	17,345	722.7
Feb-23	24	16,668	694.5
Mar-23	24	13,776	574.0
Apr-23	24	11,514	479.7
May-23	24	9,839	410.0
Jun-23	24	8,984	374.3
Jul-23	24	9,223	384.3
Aug-23	24	11,461	477.6
Sep-23	24	11,736	489.0
Total			6,182.0

UGI Utilities, Inc. - Gas Division
Industrial - Combined Rate N, NT, and DS

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	1,467	259,165	148,424	110,741	335	330.0946	350	4,792	263,957	176.66	179.93	
Nov-12	1,476	391,756	148,424	243,332	785	310.1494	672	(34,912)	356,844	265.42	241.76	
Dec-12	1,480	520,902	148,424	372,478	853	436.4428	952	43,015	563,917	351.96	381.03	
Jan-13	1,479	642,939	148,424	494,515	1,047	472.3484	1,120	34,515	677,454	434.71	458.05	
Feb-13	1,481	634,585	148,424	486,161	974	499.0415	962	(6,083)	628,502	428.48	424.38	
Mar-13	1,480	529,677	148,424	381,253	884	431.5128	805	(33,885)	495,792	357.89	334.99	
Apr-13	1,476	326,304	148,424	177,880	427	416.8202	414	(5,316)	320,987	221.07	217.47	
May-13	1,470	167,138	148,424	18,715	178	104.9164	164	(1,508)	165,630	113.70	112.67	
Jun-13	1,459	135,191	135,191	0	21	0.0000	30	0	135,191	92.66	92.66	
Jul-13	1,457	142,941	142,941	0	4	0.0000	0	0	142,941	98.11	98.11	
Aug-13	1,457	150,155	139,066	11,089	12	216.4754	16	800	150,955	103.06	103.61	
Sep-13	1,450	153,623	139,066	14,557	143	102.0312	83	(6,088)	147,535	105.95	101.75	2746.40
Oct-13	1,452	247,396	139,066	108,330	327	330.9196	350	7,491	254,888	170.38	175.54	2742.02
Nov-13	1,461	419,619	139,066	280,553	773	363.0001	672	(36,617)	383,002	287.21	262.15	2762.40
Dec-13	1,464	620,749	139,066	481,683	1,012	476.0323	952	(28,501)	592,249	424.01	404.54	2785.92
Jan-14	1,464	840,571	139,066	701,505	1,310	535.4348	1,120	(101,818)	738,753	574.16	504.61	2832.48
Feb-14	1,462	733,326	139,066	594,260	1,114	533.4708	962	(81,061)	652,265	501.59	446.15	2854.25
Mar-14	1,455	664,866	139,066	525,800	976	538.5335	805	(92,281)	572,585	456.95	393.53	2912.79
Apr-14	1,451	326,399	139,066	187,333	467	401.4812	414	(21,120)	305,279	224.95	210.39	2905.71
May-14	1,444	217,428	139,066	78,362	152	514.0094	164	5,935	223,364	150.57	154.68	2947.72
Jun-14	1,434	143,487	143,487	0	14	0.0000	30	0	143,487	100.06	100.06	2955.12
Jul-14	1,433	153,963	153,963	0	10	0.0000	0	0	153,963	107.44	107.44	2964.46
Aug-14	1,431	154,445	148,725	5,719	13	435.5129	16	1,249	155,693	107.93	108.80	2969.65
Sep-14	1,432	172,167	148,725	23,442	98	238.2260	83	(3,669)	168,498	120.23	117.67	2985.57
Oct-14	1,435	236,773	148,725	88,048	303	290.8450	350	13,748	250,521	165.00	174.58	2984.60
Nov-14	1,447	425,403	148,725	276,678	759	364.5523	672	(31,699)	393,704	293.99	272.08	2994.54
Dec-14	1,450	641,288	148,725	492,563	909	541.7358	952	23,170	664,458	442.27	458.25	3048.24
Jan-15	1,448	758,233	148,725	609,508	1,231	495.1711	1,120	(54,916)	703,317	523.64	485.72	3029.34
Feb-15	1,447	901,400	148,725	752,674	1,275	590.3009	962	(184,805)	716,595	622.94	495.23	3078.43
Mar-15	1,442	649,620	148,725	500,894	960	521.7791	805	(80,862)	568,757	450.50	394.42	3079.32
Apr-15	1,435	299,735	148,725	151,010	403	374.5951	414	4,072	303,808	208.87	211.71	3080.64
May-15	1,427	180,682	148,725	31,957	83	385.9682	164	31,342	212,024	126.62	148.58	3074.54
Jun-15	1,423	116,549	116,549	0	32	0.0000	30	0	116,549	81.90	81.90	3056.38
Jul-15	1,422	196,406	133,412	62,995	4	380.2817	0	(1,576)	194,830	138.12	137.01	3085.95
Aug-15	1,420	150,275	150,275	0	6	0.0000	16	0	150,275	105.83	105.83	3082.98
Sep-15	1,421	166,763	133,412	33,351	42	381.3114	83	15,462	182,225	117.36	128.24	3093.55
Oct-15	1,419	259,516	133,412	126,105	378	333.7217	350	(9,302)	250,214	182.89	176.33	3095.30
Nov-15	1,421	351,420	133,412	218,008	508	428.9011	672	70,213	421,633	247.30	296.72	3119.93
Dec-15	1,421	425,797	133,412	292,386	625	467.9879	952	153,139	578,936	299.65	407.41	3069.10
Jan-16	1,422	663,186	133,412	529,774	1,130	468.9480	1,120	(4,552)	658,634	466.38	463.17	3046.56
Feb-16	1,419	663,664	133,412	530,253	936	566.6786	962	14,892	678,557	467.70	478.19	3029.52
Mar-16	1,415	423,984	133,412	290,573	582	499.5113	805	111,534	535,518	299.64	378.46	3013.56
Apr-16	1,416	295,822	133,412	162,410	468	346.9890	414	(18,757)	277,065	208.91	195.67	2997.51
May-16	1,415	194,867	133,412	61,455	221	278.2232	164	(15,827)	179,040	137.72	126.53	2975.46
Jun-16	1,412	105,184	105,184	0	25	0.0000	30	0	105,184	74.49	74.49	2968.05
Jul-16	1,414	180,566	132,180	48,385	2	312.6061	0	(592)	179,973	127.70	127.28	2958.32
Aug-16	1,413	159,177	159,177	0	3	0.0000	16	0	159,177	112.65	112.65	2965.15
Sep-16	1,412	190,675	132,180	58,495	53	396.4813	83	12,078	202,753	135.04	143.59	2980.50
Oct-16	1,417	245,047	132,180	112,867	324	348.6128	350	9,147	254,195	172.93	179.39	2983.56
Nov-16	1,418	393,808	132,180	261,627	589	444.3499	672	36,976	430,783	277.72	303.80	2990.64
Dec-16	1,415	600,831	132,180	468,651	973	481.8531	952	(9,927)	590,904	424.62	417.60	3000.83
Jan-17	1,417	676,881	132,180	544,701	961	566.8430	1,120	90,163	767,044	477.69	541.32	3078.97
Feb-17	1,411	527,698	132,180	395,518	719	550.4390	962	134,005	661,703	373.99	468.96	3069.73
Mar-17	1,412	570,494	132,180	438,314	879	498.3837	805	(37,115)	533,379	404.03	377.75	3069.02
Apr-17	1,406	295,782	132,180	163,601	264	619.4301	414	92,843	388,624	210.37	276.40	3149.76
May-17	1,403	204,448	132,180	72,267	205	352.1218	164	(14,519)	189,928	145.72	135.37	3158.60

UGI Utilities, Inc. - Gas Division
Industrial - Combined Rate N, NT, and DS

	[1]	[2]	[3] *	[4] = [2] -[3]	[5]	[6] = [4] / [5]	[7]	[8]=([7] -[5])*[6]	[9] = [8] + [2]			
	Number of	Actual	Base	Temp Sensitive	Actual	Temp Sensitive	Normal	Normalized	Total	ACT	NORM	12 MO
Month	Customers	Sales	Load	Load	DD's	Load/DD	DD's	Sales Adj	Normalized Sales	UPC	UPC	ENDED
Jun-17	1,396	159,579	159,579	0	33	0.0000	30	0	159,579	114.31	114.31	3198.42
Jul-17	1,394	148,670	148,670	0	2	0.0000	0	0	148,670	106.65	106.65	3177.79
Aug-17	1,392	163,113	154,124	8,989	19	476.4487	16	(1,366)	161,748	117.18	116.20	3181.34
Sep-17	1,385	221,802	154,124	67,678	89	757.1402	83	(4,835)	216,967	160.15	156.65	3194.40
Oct-17	1,385	223,477	154,124	69,353	227	305.0200	350	37,404	260,881	161.36	188.36	3203.37
Nov-17	1,388	447,600	154,124	293,476	684	429.1218	672	(5,106)	442,494	322.48	318.80	3218.38
Dec-17	1,388	696,001	154,124	541,877	1,087	498.3156	952	(67,480)	628,521	501.44	452.82	3253.60
Jan-18	1,392	721,051	154,124	566,927	1,156	490.5790	1,120	(17,479)	703,573	518.00	505.44	3217.73
Feb-18	1,392	534,083	154,124	379,959	775	490.5005	962	91,902	625,986	383.68	449.70	3198.47
Mar-18	1,387	582,242	154,124	428,118	905	473.2531	805	(47,149)	535,093	419.79	385.79	3206.51
Apr-18	1,384	472,037	154,124	317,912	573	555.0354	414	(88,128)	383,909	341.07	277.39	3207.50
May-18	1,379	84,079	84,079	0	69	0.0000	164	0	84,079	60.97	60.97	3133.10
Jun-18	1,371	138,638	138,638	0	29	514.1442	30	623	139,261	101.12	101.58	3120.36
Jul-18	1,367	114,004	114,004	0	2	0.0000	0	0	114,004	83.40	83.40	3097.11
Aug-18	1,362	149,081	126,321	22,759	2	514.1442	16	7,222	156,302	109.46	114.76	3095.67
Sep-18	1,357	149,840	126,321	23,519	61	384.0355	83	8,356	158,196	110.42	116.58	3055.59
Oct-18	1,362	257,484	126,321	131,163	370	354.5218	350	(7,080)	250,404	189.05	183.85	3051.08
Nov-18	1,371	415,083	126,321	288,762	773	373.7557	672	(37,598)	377,485	302.76	275.34	3007.62
Dec-18	1,377	551,550	126,321	425,229	886	479.9517	952	31,685	583,235	400.54	423.55	2978.35
Jan-19	1,379	750,209	126,321	623,887	1,146	544.2974	1,120	(14,274)	735,934	544.02	533.67	3006.58
Feb-19	1,379	594,303	126,321	467,981	904	517.6464	962	29,995	624,297	430.97	452.72	3009.59
Mar-19	1,375	560,195	126,321	433,873	826	525.5246	805	(10,826)	549,368	407.41	399.54	3023.34
Apr-19	1,368	286,879	126,321	160,557	319	502.7104	414	47,565	334,443	209.71	244.48	2990.43
May-19	1,361	188,433	126,321	62,112	121	514.1960	164	22,217	210,649	138.45	154.78	3084.23
Jun-19	1,360	147,024	126,321	20,703	25	508.4532	30	2,593	149,618	108.11	110.01	3092.67
Jul-19	1,357	142,937	142,937	0	1	0.0000	0	0	142,937	105.33	105.33	3114.61
Aug-19	1,355	149,519	149,519	0	2	0.0000	16	0	149,519	110.35	110.35	3110.19
Sep-19	1,363	109,383	109,383	0	29	0.0000	83	0	109,383	80.25	80.25	3073.87
Oct-19	1,361	204,246	146,228	58,018	266	218.0937	350	18,315	222,561	150.07	163.53	3053.54
Nov-19	1,365	449,810	146,228	303,582	764	397.5352	672	(36,439)	413,371	329.53	302.84	3081.04
Dec-19	1,361	524,407	146,228	378,180	923	409.7066	952	11,861	536,268	385.31	394.03	3051.51
Jan-20	1,358	650,037	146,228	503,810	916	550.2340	1,120	112,452	762,490	478.67	561.48	3079.32
Feb-20	1,357	584,713	146,228	438,485	822	533.4611	962	74,704	659,417	430.89	485.94	3112.54
Mar-20	1,350	302,642	146,228	156,414	595	263.0689	805	55,356	357,998	224.18	265.18	2978.18
Apr-20	1,341	237,334	146,228	91,106	488	186.7021	414	(13,812)	223,522	176.98	166.68	2900.39
May-20	1,337	323,903	146,228	177,675	217	224.8855	164	(11,924)	311,979	242.26	233.34	2978.96
Jun-20	1,337	6,152	6,152	0	13	0.0000	30	0	6,152	4.60	4.60	2873.55
Jul-20	1,330	99,166	99,166	0	0	0.0000	0	0	99,166	74.56	74.56	2842.78
Aug-20	1,323	107,058	107,058	0	0	0.0000	16	0	107,058	80.92	80.92	2813.35
Sep-20	1,330	133,855	133,855	0	88	0.0000	83	0	133,855	100.64	100.64	2833.74
Oct-20	1,334	201,824	146,228	55,596	309	179.9238	350	7,377	209,201	151.29	156.82	2827.04
Nov-20	1,331	289,168	146,228	142,941	507	281.9344	672	46,519	335,688	217.26	252.21	2776.41
Dec-20	1,332	502,064	146,228	355,836	940	378.5488	952	4,543	506,606	376.92	380.34	2762.72
Jan-21	1,341	600,851	146,228	454,623	1,025	443.5348	1,120	42,136	642,987	448.06	479.48	2680.72
Feb-21	1,342	556,338	146,228	410,110	969	423.2300	962	(2,963)	553,375	414.56	412.35	2607.13
Mar-21	1,344	463,550	146,228	317,322	649	488.9396	805	76,275	539,824	344.90	401.65	2743.60
Apr-21	1,340	254,490	146,228	108,262	388	279.0265	414	7,255	261,745	189.92	195.33	2772.25
May-21	1,331	222,012	146,228	75,784	204	371.4926	164	(14,860)	207,153	166.80	155.64	2694.55
Jun-21	1,326	87,783	87,783	0	12	0.0000	30	0	87,783	66.20	66.20	2756.15
Jul-21	1,329	126,619	126,619	0	0	0.0000	0	0	126,619	95.27	95.27	2776.86
Aug-21	1,330	136,505	136,505	0	0	0.0000	16	0	136,505	102.63	102.63	2798.57
Sep-21	1,328	130,853	130,853	0	53	0.0000	83	0	130,853	98.53	98.53	2796.47

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Industrial - Rate NT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Oct-12	511	54,511	26,563	27,947	335	83.3049	350	1,209	55,720	106.67	109.04	
Nov-12	505	100,881	26,563	74,318	785	94.7256	672	(10,663)	90,219	199.77	178.65	
Dec-12	504	121,743	26,563	95,180	853	111.5251	952	10,992	132,735	241.55	263.36	
Jan-13	498	148,705	26,563	122,142	1,047	116.6673	1,120	8,525	157,230	298.61	315.72	
Feb-13	498	151,707	26,563	125,144	974	128.4598	962	(1,566)	150,141	304.63	301.49	
Mar-13	492	123,833	26,563	97,270	884	110.0930	805	(8,645)	115,188	251.69	234.12	
Apr-13	485	74,867	26,563	48,304	427	113.1899	414	(1,444)	73,424	154.37	151.39	
May-13	479	38,578	26,563	12,015	178	67.3597	164	(968)	37,610	80.54	78.52	
Jun-13	475	25,638	25,638	0	21	0.0000	30	0	25,638	53.97	53.97	
Jul-13	470	27,363	27,363	0	4	0.0000	0	0	27,363	58.22	58.22	
Aug-13	466	29,901	26,501	3,400	12	52.2811	16	193	30,094	64.16	64.58	
Sep-13	452	30,929	26,501	4,429	143	31.0408	83	(1,852)	29,077	68.43	64.33	1873.40
Oct-13	450	50,569	26,501	24,068	327	73.5214	350	1,664	52,233	112.37	116.07	1880.43
Nov-13	453	103,788	26,501	77,287	773	99.9996	672	(10,087)	93,700	229.11	206.84	1908.62
Dec-13	461	142,792	26,501	116,291	1,012	114.9270	952	(6,881)	135,911	309.74	294.82	1940.08
Jan-14	461	190,198	26,501	163,697	1,310	124.9446	1,120	(23,759)	166,439	412.58	361.04	1985.39
Feb-14	461	169,059	26,501	142,558	1,114	127.9751	962	(19,446)	149,613	366.72	324.54	2008.44
Mar-14	454	156,725	26,501	130,224	976	133.3780	805	(22,855)	133,870	345.21	294.87	2069.19
Apr-14	444	71,045	26,501	44,544	467	95.4645	414	(5,022)	66,023	160.01	148.70	2066.50
May-14	443	43,235	26,501	16,735	152	109.7693	164	1,267	44,503	97.60	100.46	2088.44
Jun-14	441	32,901	26,501	6,401	14	102.6169	30	1,688	34,589	74.61	78.43	2112.90
Jul-14	437	29,971	29,971	0	10	0.0000	0	0	29,971	68.58	68.58	2123.26
Aug-14	436	31,425	31,425	0	13	0.0000	16	0	31,425	72.07	72.07	2130.76
Sep-14	440	31,552	30,698	854	98	8.6752	83	(134)	31,418	71.71	71.40	2137.83
Oct-14	444	48,633	30,698	17,935	303	59.2442	350	2,800	51,433	109.53	115.84	2137.60
Nov-14	444	102,465	30,698	71,767	759	94.5606	672	(8,222)	94,243	230.78	212.26	2143.02
Dec-14	444	136,845	30,698	106,147	909	116.7441	952	4,993	141,838	308.21	319.46	2167.65
Jan-15	447	170,827	30,698	140,129	1,231	113.8425	1,120	(12,626)	158,201	382.16	353.92	2160.53
Feb-15	447	188,116	30,698	157,419	1,275	123.4588	962	(38,651)	149,465	420.84	334.37	2170.37
Mar-15	445	142,415	30,698	111,717	960	116.3748	805	(18,035)	124,380	320.03	279.50	2155.01
Apr-15	446	62,580	30,698	31,882	403	79.0862	414	860	63,440	140.31	142.24	2148.55
May-15	450	36,639	30,698	5,941	83	71.7508	164	5,826	42,465	81.42	94.37	2142.46
Jun-15	455	30,684	30,684	0	32	0.0000	30	0	30,684	67.44	67.44	2131.46
Jul-15	458	29,406	29,406	0	4	0.0000	0	0	29,406	64.20	64.20	2127.08
Aug-15	459	28,550	28,550	0	6	0.0000	16	0	28,550	62.20	62.20	2117.21
Sep-15	463	27,877	27,877	0	42	0.0000	83	0	27,877	60.21	60.21	2106.01
Oct-15	461	53,537	28,978	24,559	378	64.9922	350	(1,812)	51,725	116.13	112.20	2102.37
Nov-15	459	79,115	28,978	50,137	508	98.6373	672	16,147	95,262	172.36	207.54	2097.66
Dec-15	462	88,815	28,978	59,837	625	95.7736	952	31,340	120,154	192.24	260.07	2038.28
Jan-16	465	156,916	28,978	127,938	1,130	113.2491	1,120	(1,099)	155,817	337.45	335.09	2019.45
Feb-16	467	147,053	28,978	118,075	936	126.1862	962	3,316	150,369	314.89	321.99	2007.06
Mar-16	465	92,982	28,978	64,004	582	110.0268	805	24,567	117,549	199.96	252.79	1980.35
Apr-16	461	61,898	28,978	32,920	468	70.3335	414	(3,802)	58,096	134.27	126.02	1964.13
May-16	462	36,320	28,978	7,342	221	33.2379	164	(1,891)	34,429	78.61	74.52	1944.29
Jun-16	459	26,905	26,905	0	25	0.0000	30	0	26,905	58.62	58.62	1935.47
Jul-16	456	23,100	23,100	0	2	0.0000	0	0	23,100	50.66	50.66	1921.92
Aug-16	458	25,427	25,427	0	3	0.0000	16	0	25,427	55.52	55.52	1915.24
Sep-16	456	27,464	26,166	1,298	53	24.7147	83	753	28,217	60.23	61.88	1916.91
Oct-16	454	46,899	26,166	20,734	324	64.0404	350	1,680	48,580	103.30	107.00	1911.71
Nov-16	457	80,004	26,166	53,838	589	91.4390	672	7,609	87,613	175.06	191.71	1895.88
Dec-16	453	135,276	26,166	109,111	973	112.1842	952	(2,311)	132,965	298.62	293.52	1929.32
Jan-17	453	159,622	26,166	133,457	961	138.8818	1,120	22,091	181,713	352.37	401.13	1995.37
Feb-17	445	118,403	26,166	92,238	719	128.3666	962	31,251	149,654	266.08	336.30	2009.68
Mar-17	443	121,736	26,166	95,570	879	108.6679	805	(8,093)	113,643	274.80	256.53	2013.42
Apr-17	438	53,078	26,166	26,912	264	101.8944	414	15,272	68,350	121.18	156.05	2043.45
May-17	441	36,238	26,166	10,072	205	49.0753	164	(2,024)	34,214	82.17	77.58	2046.51

UGI Utilities, Inc. - Gas Division
Industrial - Rate NT

Month	[1] Number of Customers	[2] Actual Sales	[3] * Base Load	[4] = [2] -[3] Temp Sensitive Load	[5] Actual DD's	[6] = [4] / [5] Temp Sensitive Load/DD	[7] Normal DD's	[8]=([7] -[5])*[6] Normalized Sales Adj	[9] = [8] + [2] Total Normalized Sales	ACT UPC	NORM UPC	12 MO ENDED
Jun-17	445	25,809	25,809	0	33	0.0000	30	0	25,809	58.00	58.00	2045.89
Jul-17	449	24,244	24,244	0	2	0.0000	0	0	24,244	53.99	53.99	2049.23
Aug-17	449	25,276	25,276	0	19	0.0000	16	0	25,276	56.29	56.29	2050.00
Sep-17	453	26,556	24,760	1,796	89	20.0956	83	(128)	26,428	58.62	58.34	2046.46
Oct-17	453	23,203	23,203	0	227	0.0000	350	0	23,203	51.22	51.22	1990.68
Nov-17	452	103,201	24,760	78,441	684	114.6964	672	(1,365)	101,836	228.32	225.30	2024.27
Dec-17	461	129,284	24,760	104,524	1,087	96.1213	952	(13,016)	116,267	280.44	252.21	1982.95
Jan-18	464	167,668	24,760	142,908	1,156	123.6629	1,120	(4,406)	163,262	361.35	351.86	1933.68
Feb-18	464	134,664	24,760	109,904	775	141.8782	962	26,583	161,247	290.22	347.51	1944.89
Mar-18	465	129,004	24,760	104,244	905	115.2347	805	(11,481)	117,524	277.43	252.74	1941.10
Apr-18	470	90,708	24,760	65,948	573	115.1371	414	(18,281)	72,427	193.00	154.10	1939.15
May-18	470	32,541	24,760	7,781	69	113.3932	164	10,815	43,356	69.24	92.25	1953.82
Jun-18	470	26,484	24,760	1,724	29	59.8983	30	73	26,557	56.35	56.50	1952.32
Jul-18	472	26,133	26,133	0	2	0.0000	0	0	26,133	55.37	55.37	1953.69
Aug-18	469	36,084	36,084	0	2	0.0000	16	0	36,084	76.94	76.94	1974.34
Sep-18	462	27,657	27,657	0	61	0.0000	83	0	27,657	59.86	59.86	1975.86
Oct-18	468	52,014	31,109	20,906	370	56.5061	350	(1,128)	50,886	111.14	108.73	2033.37
Nov-18	474	87,334	31,109	56,226	773	72.7750	672	(7,321)	80,013	184.25	168.80	1976.87
Dec-18	482	126,687	31,109	95,579	886	107.8789	952	7,122	133,809	262.84	277.61	2002.28
Jan-19	484	194,677	31,109	163,569	1,146	142.7019	1,120	(3,742)	190,935	402.23	394.49	2044.91
Feb-19	482	166,566	31,109	135,458	904	149.8331	962	8,682	175,248	345.57	363.58	2060.98
Mar-19	477	142,121	31,109	111,013	826	134.4630	805	(2,770)	139,351	297.95	292.14	2100.39
Apr-19	479	70,837	31,109	39,728	319	124.3904	414	11,769	82,606	147.88	172.46	2118.74
May-19	479	52,792	31,109	21,684	121	179.5106	164	7,756	60,548	110.21	126.41	2152.90
Jun-19	476	33,215	31,109	2,107	25	84.6143	30	432	33,647	69.78	70.69	2167.08
Jul-19	474	31,451	31,451	0	1	0.0000	0	0	31,451	66.35	66.35	2178.07
Aug-19	476	34,757	34,757	0	2	0.0000	16	0	34,757	73.02	73.02	2174.15
Sep-19	476	26,167	26,167	0	29	0.0000	83	0	26,167	54.97	54.97	2169.26
Oct-19	476	41,633	33,104	8,528	266	32.0586	350	2,692	44,325	87.46	93.12	2153.65
Nov-19	477	107,387	33,104	74,283	764	97.2720	672	(8,916)	98,471	225.13	206.44	2191.28
Dec-19	476	124,495	33,104	91,390	923	99.0092	952	2,866	127,361	261.54	267.57	2181.23
Jan-20	477	188,914	33,104	155,810	916	170.1670	1,120	34,777	223,691	396.05	468.95	2255.70
Feb-20	477	157,427	33,104	124,322	822	151.2507	962	21,181	178,607	330.04	374.44	2266.55
Mar-20	480	110,910	33,104	77,806	595	130.8602	805	27,536	138,447	231.06	288.43	2262.84
Apr-20	480	84,141	33,104	51,036	488	104.5878	414	(7,737)	76,404	175.29	159.17	2249.56
May-20	478	53,570	33,104	20,465	217	94.2997	164	(5,000)	48,569	112.07	101.61	2224.76
Jun-20	478	37,163	33,104	4,059	13	99.4437	30	1,675	38,838	77.75	81.25	2235.33
Jul-20	474	21,284	21,284	0	0	0.0000	0	0	21,284	44.90	44.90	2213.88
Aug-20	468	26,360	26,360	0	0	0.0000	16	0	26,360	56.32	56.32	2197.18
Sep-20	469	33,885	23,822	10,063	88	114.6175	83	(550)	33,335	72.25	71.08	2213.29
Oct-20	468	53,909	23,822	30,086	309	97.3669	350	3,992	57,901	115.19	123.72	2243.89
Nov-20	466	75,394	23,822	51,572	507	101.7203	672	16,784	92,178	161.79	197.81	2235.26
Dec-20	467	143,204	23,822	119,381	940	127.0016	952	1,524	144,728	306.65	309.91	2277.60
Jan-21	461	182,239	23,822	158,417	1,025	154.5529	1,120	14,683	196,921	395.31	427.16	2235.81
Feb-21	463	168,167	23,822	144,345	969	148.9629	962	(1,043)	167,124	363.21	360.96	2222.33
Mar-21	458	109,638	23,822	85,816	649	132.2285	805	20,628	130,266	239.39	284.42	2218.32
Apr-21	456	74,328	23,822	50,506	388	130.1689	414	3,384	77,712	163.00	170.42	2229.57
May-21	449	43,777	23,822	19,955	204	97.8179	164	(3,913)	39,864	97.50	88.78	2216.74
Jun-21	450	29,594	23,822	5,772	12	113.9934	30	2,052	31,646	65.76	70.32	2205.82
Jul-21	449	30,916	30,916	0	0	0.0000	0	0	30,916	68.86	68.86	2229.77
Aug-21	446	32,165	32,165	0	0	0.0000	16	0	32,165	72.12	72.12	2245.56
Sep-21	441	30,033	30,033	0	53	0.0000	83	0	30,033	68.10	68.10	2242.59

* Baseload is the average of July and August sales

UGI Utilities, Inc. - Gas Division
Industrial - Rate DS

	[1] Number of Customers	[2] Budget Sales	[3] Budget UPC
Oct-22	202	111,983	554.4
Nov-22	202	169,340	838.3
Dec-22	202	249,210	1,233.7
Jan-23	202	295,073	1,460.8
Feb-23	202	300,965	1,489.9
Mar-23	202	238,978	1,183.1
Apr-23	202	152,648	755.7
May-23	202	98,092	485.6
Jun-23	202	82,382	407.8
Jul-23	202	71,681	354.9
Aug-23	202	72,064	356.8
Sep-23	202	80,045	396.3
Total			9,517.1

SDR-RR-6

Request:

If past weather normalized sales or sales trends are used in models or otherwise relied on in reaching sales projections, please provide actual and normalized throughput by month by rate schedule from the beginning of the historic test year and the future test year through the most recent month available and update as additional data become available. Separately identify sales and transportation throughput and provide the work papers which develop normalized sales.

Response:

Please see the response to SDR-RR-5.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-7

Request:

Please provide the work paper developing the Company's FTY load growth adjustment.

Response:

Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-8

Request:

Please provide a complete copy of the computer output generated by the Company's statistical analysis package for all residential, commercial, public authority and industrial econometric models of gas demand estimated by the Company, but not presented in the filing.

Response:

None.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-9

Request:

Identify the historical data source(s) for each dependent and independent variable utilized to develop the econometric models of gas demands for each forecasted customer group.

Response:

The variables noted below were utilized for the development of normalized and annualized usage for the Residential Heating ("RH") and Commercial Heating ("CH") customer groups, except as noted. Budgeting representing normalized and annualized usage was performed on an individual customer basis for Rate DS, Rate LFD, Rate XD and Rate IS by UGI Marketing personnel, with the exception of any new customer additions or losses for Rates LFD, XD and IS. The RH customer group is comprised of heating customers within Rates R and RT and the CH customer group is comprised of heating customers within Rates N, NT and DS.

(1) Monthly Sales – Monthly sales is a dependent variable in the econometric model. These sales are expressed in the form of use per customer which are developed from reported monthly sales and customer counts.

(2) Monthly Customers – Customers is an independent variable. Reported end of month customer counts are used in conjunction with monthly sales to develop use per customer.

(3) Monthly Heating Degree Days – Actual monthly Heating Degree Days (“HDD”) is an independent variable. HDD are calculated on a 65 degree Fahrenheit temperature base using the daily average temperature of a Gas Day and then summed by month to arrive at the Monthly Heating Degree Days. Each Gas Day is based upon the North American Standards Board definition of a Gas Day which encompasses the 24 hour period from 10:00 a.m. to 10:00 a.m. The recording locations for temperature weather data used to calculate HDD for UGI Gas are the NOAA recording stations at: Wilkes-Barre/Scranton, PA (KAVP); Allentown, PA (KABE); Reading, PA (KRDG); Lancaster, PA (KLNS); Harrisburg, PA (KMDT), Altoona, PA (KAOO), Clearfield, PA (KFIG), and Bradford, PA (KBFD). Weighting of stations is based on historical throughput within geographic delivery regions to produce a composite HDD combined value.

SDR-RR-9 (Continued)

(4) Lagged Monthly Heating Degree Days – Monthly Heating Degree Days lagged by one month.

(5) Weighted Time Trend – Weighted Time Trend is an independent variable. This variable captures trends in customer usage which include both known and unknown factors such as structural conservation related to more efficient building envelop construction, regular cycle appliance change-outs to more efficient units, upgrades to more efficient units, installation of energy conservation measures such as set-back thermostats and manual consumer behavior changes such as lowering thermostat settings in response to higher energy prices. This numeric variable represents the passage of time by assigning each monthly time period a sequential numeric value. This variable is weighted by the HDD variable in order to capture trend impacts during associated heating use periods. This variable is used for the RH group forecasting (Rates R and RT) but is excluded for the CH group forecasting (including Rates N, NT and DS).

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-10

Request:

Identify the source(s) and supporting documentation for the FTY value of each independent variable which required forecasting in the Company's gas demand models.

Response:

(1) Monthly Customers – Monthly customer counts utilized are produced by a Marketing department forecast through the Fully Projected Future Test Year. Attachment SDR-RR-11 provides the supporting data.

(2) Monthly Heating Degree Days – Normal Monthly Heating Degree Days ("HDD") are utilized for forecasting. UGI Gas utilizes a 15 year Normal HDD which is based on officially recorded daily temperatures (on a Gas Day basis) over the period January 1, 2005 to December 31, 2019. The Normal HDD are recalculated every 5 years with the most recent 15 years of HDD data. The actual system HDD is calculated using temperature data as identified in SDR-RR-9. Please see the Direct Testimony of Sherry A. Epler, UGI Gas Statement No. 8, UGI Gas Exhibit SAE-2 for HDD values.

(3) Lagged Monthly Heating Degree Days – Lagged Monthly Heating Degree Days are equal to the Monthly Heating Degree Days and are representative of the prior month's Heating Degree Days.

(4) Weighted Time Trend – The Weighted Time Trend variable is sequenced a unit value of 1 each month through the regression period and forecast based on a continuation of that same sequence for each forecast month (e.g., 100, 101, 102, etc.). A weighting of the time trend is accomplished by multiplying the trend value by the applicable monthly HDD value and dividing that product by a value of 10,000 in order to normalize to a smaller sequential value for display. This variable is used for the RH group forecasting (Rates R and RT) but is excluded for the CH group forecasting (including Rates N, NT and DS).

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-11

Request:

Please provide in hard copy and on a computer diskette in Lotus 1-2-3, QuattroPro or other spreadsheet format, the dependent and independent variable databases relied upon to produce the Company's gas demand models. For variables based on averages, include the observations which comprise the average (e.g., gas prices).

Response:

Please see Attachments SDR-RR-11(a) and SDR-RR-11(b) which have been provided in electronic (Excel) format on USB flash drive.

Prepared by or under the supervision of: Sherry A. Epler

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm	HDD Weighted Trend	Trend		ACT UPC RH Including R, RT
Oct-03	455	350	72	455	5	100	Oct-03	7.0078
Nov-03	574	672	455	574	6	101	Nov-03	8.8608
Dec-03	999	952	574	999	10	102	Dec-03	16.3404
Jan-04	1,357	1,120	999	1,357	14	103	Jan-04	22.1849
Feb-04	983	962	1,357	983	10	104	Feb-04	17.8820
Mar-04	736	805	983	736	8	105	Mar-04	13.1415
Apr-04	438	414	736	438	5	106	Apr-04	8.3402
May-04	97	164	438	97	1	107	May-04	3.1629
Jun-04	52	30	97	52	1	108	Jun-04	2.0297
Jul-04	1	0	52	1	0	109	Jul-04	1.8865
Aug-04	21	16	1	21	0	110	Aug-04	1.7963
Sep-04	59	83	21	59	1	111	Sep-04	2.1874
Oct-04	416	350	59	416	5	112	Oct-04	6.0720
Nov-04	627	672	416	627	7	113	Nov-04	9.1489
Dec-04	1,005	952	627	1,005	11	114	Dec-04	14.4608
Jan-05	1,217	1,120	1,005	1,217	14	115	Jan-05	19.6478
Feb-05	939	962	1,217	939	11	116	Feb-05	16.1939
Mar-05	942	805	939	942	11	117	Mar-05	15.5327
Apr-05	377	414	942	377	4	118	Apr-05	7.6649
May-05	268	164	377	268	3	119	May-05	4.8790
Jun-05	16	30	268	16	0	120	Jun-05	1.6443
Jul-05	0	0	16	0	0	121	Jul-05	1.6803
Aug-05	1	16	0	1	0	122	Aug-05	1.6073
Sep-05	35	83	1	35	0	123	Sep-05	1.9401
Oct-05	351	350	35	351	4	124	Oct-05	5.0649
Nov-05	600	672	351	600	7	125	Nov-05	8.6734
Dec-05	1,121	952	600	1,121	14	126	Dec-05	16.9942
Jan-06	890	1,120	1,121	890	11	127	Jan-06	13.7720
Feb-06	945	962	890	945	12	128	Feb-06	14.7974
Mar-06	775	805	945	775	10	129	Mar-06	12.3302
Apr-06	390	414	775	390	5	130	Apr-06	6.3882
May-06	184	164	390	184	2	131	May-06	3.2140
Jun-06	44	30	184	44	1	132	Jun-06	1.9441
Jul-06	1	0	44	1	0	133	Jul-06	1.7662
Aug-06	5	16	1	5	0	134	Aug-06	1.4000
Sep-06	123	83	5	123	2	135	Sep-06	2.1943
Oct-06	428	350	123	428	6	136	Oct-06	5.8159
Nov-06	552	672	428	552	8	137	Nov-06	7.7014
Dec-06	813	952	552	813	11	138	Dec-06	11.7598
Jan-07	997	1,120	813	997	14	139	Jan-07	15.3550
Feb-07	1,178	962	997	1,178	16	140	Feb-07	18.6573
Mar-07	824	805	1,178	824	12	141	Mar-07	13.2498
Apr-07	552	414	824	552	8	142	Apr-07	9.2433
May-07	142	164	552	142	2	143	May-07	3.1365
Jun-07	23	30	142	23	0	144	Jun-07	1.8097
Jul-07	13	0	23	13	0	145	Jul-07	1.6447
Aug-07	22	16	13	22	0	146	Aug-07	1.5832
Sep-07	72	83	22	72	1	147	Sep-07	1.9153
Oct-07	222	350	72	222	3	148	Oct-07	3.2246
Nov-07	739	672	222	739	11	149	Nov-07	10.2518
Dec-07	1,006	952	739	1,006	15	150	Dec-07	14.8739
Jan-08	1,051	1,120	1,006	1,051	16	151	Jan-08	16.0378
Feb-08	975	962	1,051	975	15	152	Feb-08	15.4134
Mar-08	819	805	975	819	13	153	Mar-08	12.6722
Apr-08	371	414	819	371	6	154	Apr-08	5.8446
May-08	275	164	371	275	4	155	May-08	4.0351
Jun-08	18	30	275	18	0	156	Jun-08	1.8891
Jul-08	0	0	18	0	0	157	Jul-08	1.5136
Aug-08	14	16	0	14	0	158	Aug-08	1.4545
Sep-08	80	83	14	80	1	159	Sep-08	1.8618
Oct-08	468	350	80	468	7	160	Oct-08	5.7327
Nov-08	721	672	468	721	12	161	Nov-08	9.4655

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm	HDD Weighted Trend	Trend		ACT UPC RH Including R, RT
Dec-08	1,016	952	721	1,016	16	162	Dec-08	14.6975
Jan-09	1,292	1,120	1,016	1,292	21	163	Jan-09	19.7082
Feb-09	927	962	1,292	927	15	164	Feb-09	13.8864
Mar-09	774	805	927	774	13	165	Mar-09	11.7429
Apr-09	419	414	774	419	7	166	Apr-09	6.6560
May-09	179	164	419	179	3	167	May-09	3.1389
Jun-09	41	30	179	41	1	168	Jun-09	2.1056
Jul-09	15	0	41	15	0	169	Jul-09	1.5645
Aug-09	16	16	15	16	0	170	Aug-09	1.3998
Sep-09	118	83	16	118	2	171	Sep-09	2.1393
Oct-09	440	350	118	440	8	172	Oct-09	5.2306
Nov-09	571	672	440	571	10	173	Nov-09	6.9136
Dec-09	1,055	952	571	1,055	18	174	Dec-09	15.0812
Jan-10	1,157	1,120	1,055	1,157	20	175	Jan-10	17.3565
Feb-10	1,014	962	1,157	1,014	18	176	Feb-10	15.1844
Mar-10	627	805	1,014	627	11	177	Mar-10	9.2957
Apr-10	325	414	627	325	6	178	Apr-10	4.7929
May-10	153	164	325	153	3	179	May-10	2.9903
Jun-10	25	30	153	25	0	180	Jun-10	1.8194
Jul-10	4	0	25	4	0	181	Jul-10	1.5217
Aug-10	7	16	4	7	0	182	Aug-10	1.3849
Sep-10	67	83	7	67	1	183	Sep-10	1.7551
Oct-10	383	350	67	383	7	184	Oct-10	4.1760
Nov-10	669	672	383	669	12	185	Nov-10	8.6331
Dec-10	1,162	952	669	1,162	22	186	Dec-10	16.8751
Jan-11	1,251	1,120	1,162	1,251	23	187	Jan-11	18.3738
Feb-11	955	962	1,251	955	18	188	Feb-11	14.4647
Mar-11	836	805	955	836	16	189	Mar-11	12.6837
Apr-11	414	414	836	414	8	190	Apr-11	6.4427
May-11	125	164	414	125	2	191	May-11	3.0152
Jun-11	21	30	125	21	0	192	Jun-11	1.7951
Jul-11	1	0	21	1	0	193	Jul-11	1.7186
Aug-11	10	16	1	10	0	194	Aug-11	1.5592
Sep-11	74	83	10	74	1	195	Sep-11	2.1090
Oct-11	400	350	74	400	8	196	Oct-11	5.2986
Nov-11	559	672	400	559	11	197	Nov-11	7.3983
Dec-11	843	952	559	843	17	198	Dec-11	12.0499
Jan-12	1,002	1,120	843	1,002	20	199	Jan-12	15.2441
Feb-12	814	962	1,002	814	16	200	Feb-12	12.2557
Mar-12	487	805	814	487	10	201	Mar-12	6.8059
Apr-12	437	414	487	437	9	202	Apr-12	6.2599
May-12	73	164	437	73	1	203	May-12	2.0733
Jun-12	39	30	73	39	1	204	Jun-12	1.8285
Jul-12	1	0	39	1	0	205	Jul-12	1.4190
Aug-12	7	16	1	7	0	206	Aug-12	1.3744
Sep-12	110	83	7	110	2	207	Sep-12	2.2875
Oct-12	335	350	110	335	7	208	Oct-12	4.0937
Nov-12	785	672	335	785	16	209	Nov-12	11.5970
Dec-12	853	952	785	853	18	210	Dec-12	11.8956
Jan-13	1,047	1,120	853	1,047	22	211	Jan-13	16.1991
Feb-13	974	962	1,047	974	21	212	Feb-13	14.4516
Mar-13	884	805	974	884	19	213	Mar-13	13.1916
Apr-13	427	414	884	427	9	214	Apr-13	5.1652
May-13	178	164	427	178	4	215	May-13	2.9772
Jun-13	21	30	178	21	0	216	Jun-13	1.7263
Jul-13	4	0	21	4	0	217	Jul-13	1.7976
Aug-13	12	16	4	12	0	218	Aug-13	1.6637
Sep-13	143	83	12	143	3	219	Sep-13	2.5655
Oct-13	327	350	143	327	7	220	Oct-13	4.4169
Nov-13	773	672	327	773	17	221	Nov-13	11.1280
Dec-13	1,012	952	773	1,012	22	222	Dec-13	14.5324
Jan-14	1,310	1,120	1,012	1,310	29	223	Jan-14	20.3868

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm	HDD Weighted Trend	Trend		ACT UPC RH Including R, RT
Feb-14	1,114	962	1,310	1,114	25	224	Feb-14	16.2831
Mar-14	976	805	1,114	976	22	225	Mar-14	14.2483
Apr-14	467	414	976	467	11	226	Apr-14	6.5384
May-14	152	164	467	152	3	227	May-14	2.5752
Jun-14	14	30	152	14	0	228	Jun-14	1.6773
Jul-14	10	0	14	10	0	229	Jul-14	1.4405
Aug-14	13	16	10	13	0	230	Aug-14	1.4523
Sep-14	98	83	13	98	2	231	Sep-14	2.9907
Oct-14	303	350	98	303	7	232	Oct-14	3.7460
Nov-14	759	672	303	759	18	233	Nov-14	11.3022
Dec-14	909	952	759	909	21	234	Dec-14	12.9348
Jan-15	1,231	1,120	909	1,231	29	235	Jan-15	19.4205
Feb-15	1,275	962	1,231	1,275	30	236	Feb-15	19.7387
Mar-15	960	805	1,275	960	23	237	Mar-15	13.9637
Apr-15	403	414	960	403	10	238	Apr-15	6.1430
May-15	83	164	403	83	2	239	May-15	2.3679
Jun-15	32	30	83	32	1	240	Jun-15	1.9294
Jul-15	4	0	32	4	0	241	Jul-15	1.6046
Aug-15	6	16	4	6	0	242	Aug-15	1.6193
Sep-15	42	83	6	42	1	243	Sep-15	1.8298
Oct-15	378	350	42	378	9	244	Oct-15	5.0175
Nov-15	508	672	378	508	12	245	Nov-15	7.0053
Dec-15	625	952	508	625	15	246	Dec-15	8.5739
Jan-16	1,130	1,120	625	1,130	28	247	Jan-16	17.7713
Feb-16	936	962	1,130	936	23	248	Feb-16	13.9226
Mar-16	582	805	936	582	14	249	Mar-16	8.8177
Apr-16	468	414	582	468	12	250	Apr-16	6.8525
May-16	221	164	468	221	6	251	May-16	3.3426
Jun-16	25	30	221	25	1	252	Jun-16	2.0974
Jul-16	2	0	25	2	0	253	Jul-16	1.4873
Aug-16	3	16	2	3	0	254	Aug-16	1.2610
Sep-16	53	83	3	53	1	255	Sep-16	1.5356
Oct-16	324	350	53	324	8	256	Oct-16	4.3445
Nov-16	589	672	324	589	15	257	Nov-16	8.4619
Dec-16	973	952	589	973	25	258	Dec-16	14.7413
Jan-17	961	1,120	973	961	25	259	Jan-17	14.2207
Feb-17	719	962	961	719	19	260	Feb-17	11.1925
Mar-17	879	805	719	879	23	261	Mar-17	14.0474
Apr-17	264	414	879	264	7	262	Apr-17	3.9713
May-17	205	164	264	205	5	263	May-17	3.4362
Jun-17	33	30	205	33	1	264	Jun-17	2.0802
Jul-17	2	0	33	2	0	265	Jul-17	1.3968
Aug-17	19	16	2	19	1	266	Aug-17	0.9624
Sep-17	89	83	19	89	2	267	Sep-17	2.7446
Oct-17	227	350	89	227	6	268	Oct-17	3.2986
Nov-17	684	672	227	684	18	269	Nov-17	9.7528
Dec-17	1,087	952	684	1,087	29	270	Dec-17	17.2301
Jan-18	1,156	1,120	1,087	1,156	31	271	Jan-18	18.6779
Feb-18	775	962	1,156	775	21	272	Feb-18	12.1111
Mar-18	905	805	775	905	25	273	Mar-18	13.4365
Apr-18	573	414	905	573	16	274	Apr-18	8.5018
May-18	69	164	573	69	2	275	May-18	2.0102
Jun-18	29	30	69	29	1	276	Jun-18	1.6869
Jul-18	2	0	29	2	0	277	Jul-18	1.2628
Aug-18	2	16	2	2	0	278	Aug-18	1.2259
Sep-18	61	83	2	61	2	279	Sep-18	1.6162
Oct-18	370	350	0	370	10	280	Oct-18	5.0938
Nov-18	773	672	370	773	19	281	Nov-18	11.9798
Dec-18	886	952	773	886	27	282	Dec-18	13.5075
Jan-19	1,146	1,120	886	1,146	32	283	Jan-19	17.7587
Feb-19	904	962	1,146	904	27	284	Feb-19	15.0184
Mar-19	826	805	904	826	23	285	Mar-19	12.2318

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm	HDD Weighted Trend	Trend		ACT UPC RH Including R, RT
Apr-19	319	414	826	319	12	286	Apr-19	4.9289
May-19	121	164	319	121	5	287	May-19	2.7642
Jun-19	25	30	121	25	1	288	Jun-19	1.5825
Jul-19	1	0	25	1	0	289	Jul-19	1.3417
Aug-19	2	16	1	2	0	290	Aug-19	1.2637
Sep-19	29	83	2	29	2	291	Sep-19	1.7561
Oct-19	266	350	29	266	10	292	Oct-19	3.5555
Nov-19	764	672	266	764	20	293	Nov-19	10.7182
Dec-19	923	952	764	923	28	294	Dec-19	15.8451
Jan-20	916	1,120	923	916	33	295	Jan-20	14.3414
Feb-20	822	962	916	822	28	296	Feb-20	11.8640
Mar-20	595	805	822	595	24	297	Mar-20	8.6380
Apr-20	488	414	595	488	12	298	Apr-20	8.0616
May-20	217	164	488	217	5	299	May-20	3.8595
Jun-20	13	30	217	13	1	300	Jun-20	1.8594
Jul-20	0	0	13	0	0	301	Jul-20	1.5679
Aug-20	0	16	0	0	0	302	Aug-20	1.0233
Sep-20	88	83	0	88	3	303	Sep-20	1.7502
Oct-20	309	350	88	309	11	304	Oct-20	3.8042
Nov-20	507	672	309	507	20	305	Nov-20	8.9469
Dec-20	940	952	507	940	29	306	Dec-20	13.1806
Jan-21	1,025	1120	940	1,025	34	307	Jan-21	16.2484
Feb-21	969	962	1,025	969	30	308	Feb-21	15.3074
Mar-21	649	805	969	649	25	309	Mar-21	10.2549
Apr-21	388	414	649	388	13	310	Apr-21	5.8394
May-21	204	164	388	204	5	311	May-21	3.1482
Jun-21	12	30	204	12	1	312	Jun-21	1.5248
Jul-21	0	0	12	0	0	313	Jul-21	1.4794
Aug-21	0	16	0	0	1	314	Aug-21	1.4322
Sep-21	53	83	0	53	3	315	Sep-21	1.3694
Oct-21		350	53	0	11	316		
Nov-21		672	0	0	21	317		
Dec-21		952	0	0	30	318		
Jan-22		1120	0	0	36	319		
Feb-22		962	0	0	31	320		
Mar-22		805	0	0	26	321		
Apr-22		414	0	0	13	322		
May-22		164	0	0	5	323		
Jun-22		30	0	0	1	324		
Jul-22		0	0	0	0	325		
Aug-22		16	0	0	1	326		
Sep-22		83	0	0	3	327		
Oct-22		350	0	0	11	328		
Nov-22		672	0	0	22	329		
Dec-22		952	0	0	31	330		
Jan-23		1120	0	0	37	331		
Feb-23		962	0	0	32	332		
Mar-23		805	0	0	27	333		
Apr-23		414	0	0	14	334		
May-23		164	0	0	5	335		
Jun-23		30	0	0	1	336		
Jul-23		0	0	0	0	337		
Aug-23		16	0	0	1	338		
Sep-23		83	0	0	3	339		
Oct-23		350	0	0	12	340		
Nov-23		672	0	0	23	341		
Dec-23		952	0	0	33	342		
Jan-24		1120	0	0	38	343		
Feb-24		962	0	0	33	344		
Mar-24		805	0	0	28	345		

Regression Results:		
	0.855492	Constant
	0.000832	HDD-1
	0.013967	HDD
	-0.02549	Trend

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)	HDD Weighted Trend		1 Month UPC	12 Months Ended UPC
Oct-03	350	83	4		5.7237	
Nov-03	672	350	7		10.3593	
Dec-03	952	672	10		14.4634	
Jan-04	1,120	952	12		16.9963	
Feb-04	962	1,120	10		14.9684	
Mar-04	805	962	8		12.6837	
Apr-04	414	805	4		7.1957	
May-04	164	414	2		3.4458	
Jun-04	30	164	0		1.4027	
Jul-04	0	30	0		0.8805	
Aug-04	16	0	0		1.0745	
Sep-04	83	16	1	FY04	2.0046	91.1984
Oct-04	350	83	4		5.7130	91.1877
Nov-04	672	350	8		10.3387	91.1671
Dec-04	952	672	11		14.4343	91.1380
Jan-05	1,120	952	13		16.9620	91.1037
Feb-05	962	1,120	11		14.9389	91.0743
Mar-05	805	962	9		12.6591	91.0497
Apr-05	414	805	5		7.1830	91.0370
May-05	164	414	2		3.4408	91.0320
Jun-05	30	164	0		1.4018	91.0311
Jul-05	0	30	0		0.8805	91.0311
Aug-05	16	0	0		1.0740	91.0306
Sep-05	83	16	1	FY05	2.0020	91.0281
Oct-05	350	83	4		5.7022	91.0174
Nov-05	672	350	8		10.3182	90.9968
Dec-05	952	672	12		14.4052	90.9677
Jan-06	1,120	952	14		16.9277	90.9334
Feb-06	962	1,120	12		14.9095	90.9040
Mar-06	805	962	10		12.6345	90.8794
Apr-06	414	805	5		7.1704	90.8667
May-06	164	414	2		3.4358	90.8617
Jun-06	30	164	0		1.4009	90.8608
Jul-06	0	30	0		0.8805	90.8608
Aug-06	16	0	0		1.0735	90.8603
Sep-06	83	16	1	FY06	1.9995	90.8578
Oct-06	350	83	5		5.6915	90.8471
Nov-06	672	350	9		10.2976	90.8265
Dec-06	952	672	13		14.3760	90.7974
Jan-07	1,120	952	16		16.8935	90.7631
Feb-07	962	1,120	13		14.8801	90.7337
Mar-07	805	962	11		12.6098	90.7091
Apr-07	414	805	6		7.1577	90.6964
May-07	164	414	2		3.4308	90.6914
Jun-07	30	164	0		1.4000	90.6905
Jul-07	0	30	0		0.8805	90.6905
Aug-07	16	0	0		1.0730	90.6900
Sep-07	83	16	1	FY 07	1.9969	90.6874
Oct-07	350	83	5		5.6808	90.6767
Nov-07	672	350	10		10.2771	90.6562
Dec-07	952	672	14		14.3469	90.6271
Jan-08	1,120	952	17		16.8592	90.5928
Feb-08	962	1,120	15		14.8507	90.5634
Mar-08	805	962	12		12.5852	90.5388
Apr-08	414	805	6		7.1451	90.5261
May-08	164	414	3		3.4257	90.5211
Jun-08	30	164	0		1.3990	90.5202
Jul-08	0	30	0		0.8805	90.5202
Aug-08	16	0	0		1.0725	90.5197
Sep-08	83	16	1	FY 08	1.9944	90.5171
Oct-08	350	83	6		5.6701	90.5064
Nov-08	672	350	11		10.2565	90.4859
Dec-08	952	672	15		14.3178	90.4568

Regression Results:	0.855492	Constant
	0.000832	HDD-1
	0.013967	HDD
	-0.02549	Trend

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)	HDD Weighted Trend		1 Month UPC	12 Months Ended UPC
Jan-09	1,120	952	18		16.8250	90.4225
Feb-09	962	1,120	16		14.8212	90.3931
Mar-09	805	962	13		12.5606	90.3685
Apr-09	414	805	7		7.1324	90.3558
May-09	164	414	3		3.4207	90.3508
Jun-09	30	164	1		1.3981	90.3499
Jul-09	0	30	0		0.8805	90.3499
Aug-09	16	0	0		1.0720	90.3494
Sep-09	83	16	1	FY 09	1.9919	90.3468
Oct-09	350	83	6		5.6594	90.3361
Nov-09	672	350	12		10.2360	90.3156
Dec-09	952	672	17		14.2887	90.2865
Jan-10	1,120	952	20		16.7907	90.2522
Feb-10	962	1,120	17		14.7918	90.2228
Mar-10	805	962	14		12.5360	90.1981
Apr-10	414	805	7		7.1197	90.1855
May-10	164	414	3		3.4157	90.1805
Jun-10	30	164	1		1.3972	90.1796
Jul-10	0	30	0		0.8805	90.1796
Aug-10	16	0	0		1.0715	90.1791
Sep-10	83	16	2	FY 10	1.9893	90.1765
Oct-10	350	83	6		5.6487	90.1658
Nov-10	672	350	12		10.2154	90.1453
Dec-10	952	672	18		14.2596	90.1161
Jan-11	1,120	952	21		16.7565	90.0819
Feb-11	962	1,120	18		14.7624	90.0525
Mar-11	805	962	15		12.5113	90.0278
Apr-11	414	805	8		7.1071	90.0152
May-11	164	414	3		3.4107	90.0102
Jun-11	30	164	1		1.3963	90.0092
Jul-11	0	30	0		0.8805	90.0092
Aug-11	16	0	0		1.0710	90.0088
Sep-11	83	16	2	FY 11	1.9868	90.0062
Oct-11	350	83	7		5.6380	89.9955
Nov-11	672	350	13		10.1949	89.9750
Dec-11	952	672	19		14.2304	89.9458
Jan-12	1,120	952	22		16.7222	89.9116
Feb-12	962	1,120	19		14.7330	89.8822
Mar-12	805	962	16		12.4867	89.8575
Apr-12	414	805	8		7.0944	89.8449
May-12	164	414	3		3.4057	89.8399
Jun-12	30	164	1		1.3954	89.8389
Jul-12	0	30	0		0.8805	89.8389
Aug-12	16	0	0		1.0706	89.8384
Sep-12	83	16	2	FY 12	1.9842	89.8359
Oct-12	350	83	7		5.6273	89.8252
Nov-12	672	350	14		10.1743	89.8046
Dec-12	952	672	20		14.2013	89.7755
Jan-13	1,120	952	24		16.6879	89.7413
Feb-13	962	1,120	20		14.7035	89.7118
Mar-13	805	962	17		12.4621	89.6872
Apr-13	414	805	9		7.0817	89.6746
May-13	164	414	4		3.4007	89.6695
Jun-13	30	164	1		1.3944	89.6686
Jul-13	0	30	0		0.8805	89.6686
Aug-13	16	0	0		1.0701	89.6681
Sep-13	83	16	2	FY 13	1.9817	89.6656
Oct-13	350	83	8		5.6166	89.6549
Nov-13	672	350	15		10.1538	89.6343
Dec-13	952	672	21		14.1722	89.6052
Jan-14	1,120	952	25		16.6537	89.5710
Feb-14	962	1,120	22		14.6741	89.5415
Mar-14	805	962	18		12.4375	89.5169

Regression Results:	0.855492	Constant
	0.000832	HDD-1
	0.013967	HDD
	-0.02549	Trend

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)	HDD Weighted Trend		1 Month UPC	12 Months Ended UPC
Apr-14	414	805	9		7.0691	89.5043
May-14	164	414	4		3.3956	89.4992
Jun-14	30	164	1		1.3935	89.4983
Jul-14	0	30	0		0.8805	89.4983
Aug-14	16	0	0		1.0696	89.4978
Sep-14	83	16	2	FY 14	1.9792	89.4953
Oct-14	350	83	8		5.6059	89.4846
Nov-14	672	350	16		10.1332	89.4640
Dec-14	952	672	22		14.1431	89.4349
Jan-15	1,120	952	26		16.6194	89.4007
Feb-15	962	1,120	23		14.6447	89.3712
Mar-15	805	962	19		12.4129	89.3466
Apr-15	414	805	10		7.0564	89.3339
May-15	164	414	4		3.3906	89.3289
Jun-15	30	164	1		1.3926	89.3280
Jul-15	0	30	0		0.8805	89.3280
Aug-15	16	0	0		1.0691	89.3275
Sep-15	83	16	2	FY 15	1.9766	89.3250
Oct-15	350	83	9		5.5952	89.3143
Nov-15	672	350	16		10.1126	89.2937
Dec-15	952	672	23		14.1140	89.2646
Jan-16	1,120	952	28		16.5852	89.2303
Feb-16	962	1,120	24		14.6153	89.2009
Mar-16	805	962	20		12.3882	89.1763
Apr-16	414	805	10		7.0437	89.1636
May-16	164	414	4		3.3856	89.1586
Jun-16	30	164	1		1.3917	89.1577
Jul-16	0	30	0		0.8805	89.1577
Aug-16	16	0	0		1.0686	89.1572
Sep-16	83	16	2	FY 16	1.9741	89.1547
Oct-16	350	83	9		5.5845	89.1440
Nov-16	672	350	17		10.0921	89.1234
Dec-16	952	672	25		14.0849	89.0943
Jan-17	1,120	952	29		16.5509	89.0600
Feb-17	962	1,120	25		14.5858	89.0306
Mar-17	805	962	21		12.3636	89.0060
Apr-17	414	805	11		7.0311	88.9933
May-17	164	414	4		3.3806	88.9883
Jun-17	30	164	1		1.3908	88.9874
Jul-17	0	30	0		0.8805	88.9874
Aug-17	16	0	0		1.0681	88.9869
Sep-17	83	16	2	FY 17	1.9715	88.9844
Oct-17	350	83	9		5.5738	88.9737
Nov-17	672	350	18		10.0715	88.9531
Dec-17	952	672	26		14.0557	88.9240
Jan-18	1,120	952	30		16.5167	88.8897
Feb-18	962	1,120	26		14.5564	88.8603
Mar-18	805	962	22		12.3390	88.8357
Apr-18	414	805	11		7.0184	88.8230
May-18	164	414	5		3.3756	88.8180
Jun-18	30	164	1		1.3899	88.8171
Jul-18	0	30	0		0.8805	88.8171
Aug-18	16	0	0		1.0676	88.8166
Sep-18	83	16	2	FY 18	1.9690	88.8141
Oct-18	350	83	10		5.5631	88.8034
Nov-18	672	350	19		10.0510	88.7828
Dec-18	952	672	27		14.0266	88.7537
Jan-19	1,120	952	32		16.4824	88.7194
Feb-19	962	1,120	27		14.5270	88.6900
Mar-19	805	962	23		12.3144	88.6654
Apr-19	414	805	12		7.0058	88.6527

Regression Results:		
	0.855492	Constant
	0.000832	HDD-1
	0.013967	HDD
	-0.02549	Trend

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)	HDD Weighted Trend		1 Month UPC	12 Months Ended UPC	
May-19	164	414	5		3.3706	88.6477	
Jun-19	30	164	1		1.3889	88.6468	
Jul-19	0	30	0		0.8805	88.6468	
Aug-19	16	0	0		1.0671	88.6463	
Sep-19	83	16	2	FY 19	1.9665	88.6437	
Oct-19	350	83	10		5.5524	88.6330	
Nov-19	672	350	20		10.0304	88.6125	
Dec-19	952	672	28		13.9975	88.5834	
Jan-20	1,120	952	33		16.4481	88.5491	
Feb-20	962	1,120	28		14.4976	88.5197	
Mar-20	805	962	24		12.2897	88.4951	
Apr-20	414	805	12		6.9931	88.4824	
May-20	164	414	5		3.3655	88.4774	
Jun-20	30	164	1		1.3880	88.4765	
Jul-20	0	30	0		0.8805	88.4765	
Aug-20	16	0	0		1.0666	88.4760	
Sep-20	83	16	3	FY 20	1.9639	88.4734	
Oct-20	350	83	11		5.5417	88.4627	
Nov-20	672	350	20		10.0099	88.4422	
Dec-20	952	672	29		13.9684	88.4131	
Jan-21	1,120	952	34		16.4139	88.3788	
Feb-21	962	1,120	30		14.4682	88.3494	
Mar-21	805	962	25		12.2651	88.3248	
Apr-21	414	805	13		6.9804	88.3121	
May-21	164	414	5		3.3605	88.3071	
Jun-21	30	164	1		1.3871	88.3062	
Jul-21	0	30	0		0.8805	88.3062	
Aug-21	16	0	1		1.0662	88.3057	
Sep-21	83	16	3	FY 21	1.9614	88.3031	
Oct-21	350	83	11		5.5310	88.2924	
Nov-21	672	350	21		9.9893	88.2719	
Dec-21	952	672	30		13.9393	88.2428	
Jan-22	1,120	952	36		16.3796	88.2085	
Feb-22	962	1,120	31		14.4387	88.1791	
Mar-22	805	962	26		12.2405	88.1544	Historic Test Year Annualized FY 21
Apr-22	414	805	13		6.9678	88.1418	
May-22	164	414	5		3.3555	88.1368	
Jun-22	30	164	1		1.3862	88.1359	
Jul-22	0	30	0		0.8805	88.1359	
Aug-22	16	0	1		1.0657	88.1354	
Sep-22	83	16	3	FY 22	1.9589	88.1328	
Oct-22	350	83	11		5.5203	88.1221	
Nov-22	672	350	22		9.9688	88.1016	
Dec-22	952	672	31		13.9101	88.0724	
Jan-23	1,120	952	37		16.3454	88.0382	
Feb-23	962	1,120	32		14.4093	88.0088	
Mar-23	805	962	27		12.2159	87.9841	Future Test Year Annualized FY 22
Apr-23	414	805	14		6.9551	87.9715	
May-23	164	414	5		3.3505	87.9665	
Jun-23	30	164	1		1.3853	87.9655	
Jul-23	0	30	0		0.8805	87.9655	
Aug-23	16	0	1		1.0652	87.9651	
Sep-23	83	16	3	FY 23	1.9563	87.9625	
Oct-23	350	83	12		5.5095	87.9518	
Nov-23	672	350	23		9.9482	87.9313	
Dec-23	952	672	33		13.8810	87.9021	
Jan-24	1,120	952	38		16.3111	87.8679	
Feb-24	962	1,120	33		14.3799	87.8385	
Mar-24	805	962	28		12.1912	87.8138	Fully Projected Future Test Year Annualized FY 23

Combined Class RH incl. R, RT
UPC History 10/03-9/21

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.991216961
R Square	0.982511063
Adjusted R Square	0.982263578
Standard Error	0.779603512
Observations	216

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	7238.648193	2412.882731	3969.982949	6.2484E-186
Residual	212	128.8497068	0.607781636		
Total	215	7367.4979			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.855492263	0.082024608	10.42970258	7.99903E-21	0.69380396	1.017180565	0.69380396	1.017180565
X Variable 1	0.000832173	0.00022623	3.678435247	0.00029753	0.000386224	0.001278122	0.000386224	0.001278122
X Variable 2	0.013966588	0.000338264	41.28904654	2.5251E-103	0.013299797	0.01463338	0.013299797	0.01463338
X Variable 3	-0.025489148	0.012852842	-1.983152624	0.048641189	-0.05082489	-0.000153407	-0.05082489	-0.000153407

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm		ACT UPC CH Including N, NT, DS
Oct-12	335	350	110	335	Oct-12	26.2133
Nov-12	785	672	335	785	Nov-12	57.0139
Dec-12	853	952	785	853	Dec-12	75.8326
Jan-13	1,047	1,120	853	1,047	Jan-13	93.2957
Feb-13	974	962	1,047	974	Feb-13	87.1142
Mar-13	884	805	974	884	Mar-13	72.4338
Apr-13	427	414	884	427	Apr-13	38.4063
May-13	178	164	427	178	May-13	18.3230
Jun-13	21	30	178	21	Jun-13	13.1382
Jul-13	4	0	21	4	Jul-13	11.0372
Aug-13	12	16	4	12	Aug-13	12.8748
Sep-13	143	83	12	143	Sep-13	15.8076
Oct-13	327	350	143	327	Oct-13	25.2827
Nov-13	773	672	327	773	Nov-13	57.8559
Dec-13	1,012	952	773	1,012	Dec-13	89.2557
Jan-14	1,310	1,120	1,012	1,310	Jan-14	118.7481
Feb-14	1,114	962	1,310	1,114	Feb-14	100.5934
Mar-14	976	805	1,114	976	Mar-14	85.0976
Apr-14	467	414	976	467	Apr-14	38.1561
May-14	152	164	467	152	May-14	18.4903
Jun-14	14	30	152	14	Jun-14	11.9605
Jul-14	10	0	14	10	Jul-14	13.1005
Aug-14	13	16	10	13	Aug-14	12.6120
Sep-14	98	83	13	98	Sep-14	18.3857
Oct-14	303	350	98	303	Oct-14	23.0688
Nov-14	759	672	303	759	Nov-14	58.8037
Dec-14	909	952	759	909	Dec-14	85.8066
Jan-15	1,231	1,120	909	1,231	Jan-15	111.5065
Feb-15	1,275	962	1,231	1,275	Feb-15	115.1389
Mar-15	960	805	1,275	960	Mar-15	88.8316
Apr-15	403	414	960	403	Apr-15	35.1852
May-15	83	164	403	83	May-15	15.1005
Jun-15	32	30	83	32	Jun-15	14.5378
Jul-15	4	0	32	4	Jul-15	12.4361
Aug-15	6	16	4	6	Aug-15	15.2095
Sep-15	42	83	6	42	Sep-15	14.3887
Oct-15	378	350	42	378	Oct-15	26.4583
Nov-15	508	672	378	508	Nov-15	43.8464
Dec-15	625	952	508	625	Dec-15	54.8538
Jan-16	1,130	1,120	625	1,130	Jan-16	98.3854
Feb-16	936	962	1,130	936	Feb-16	89.0672
Mar-16	582	805	936	582	Mar-16	50.1565
Apr-16	468	414	582	468	Apr-16	35.3421
May-16	221	164	468	221	May-16	20.3559
Jun-16	25	30	221	25	Jun-16	14.6658
Jul-16	2	0	25	2	Jul-16	11.5077
Aug-16	3	16	2	3	Aug-16	15.4927
Sep-16	53	83	3	53	Sep-16	13.5444
Oct-16	324	350	53	324	Oct-16	24.1222
Nov-16	589	672	324	589	Nov-16	46.5639
Dec-16	973	952	589	973	Dec-16	85.9383
Jan-17	961	1,120	973	961	Jan-17	93.9389
Feb-17	719	962	961	719	Feb-17	67.4803
Mar-17	879	805	719	879	Mar-17	74.4178
Apr-17	264	414	879	264	Apr-17	30.8584
May-17	205	164	264	205	May-17	21.2359
Jun-17	33	30	205	33	Jun-17	12.5259
Jul-17	2	0	33	2	Jul-17	14.2208
Aug-17	19	16	2	19	Aug-17	13.5311
Sep-17	89	83	19	89	Sep-17	13.9642
Oct-17	227	350	89	227	Oct-17	22.6190
Nov-17	684	672	227	684	Nov-17	60.3793
Dec-17	1,087	952	684	1,087	Dec-17	87.6191
Jan-18	1,156	1,120	1,087	1,156	Jan-18	113.3025
Feb-18	775	962	1,156	775	Feb-18	74.7883
Mar-18	905	805	775	905	Mar-18	82.1497
Apr-18	573	414	905	573	Apr-18	51.8098
May-18	69	164	573	69	May-18	19.7730
Jun-18	29	30	69	29	Jun-18	14.9547

	ACT DD Calendar	Norm DD Calendar	HDDm-1	HDDm
Jul-18	2	0	29	2
Aug-18	2	16	2	2
Sep-18	61	83	2	61
Oct-18	370	350	0	370
Nov-18	773	672	370	773
Dec-18	886	952	773	886
Jan-19	1,146	1,120	886	1,146
Feb-19	904	962	1,146	904
Mar-19	826	805	904	826
Apr-19	319	414	826	319
May-19	121	164	319	121
Jun-19	25	30	121	25
Jul-19	1	0	25	1
Aug-19	2	16	1	2
Sep-19	29	83	2	29
Oct-19	266	350	29	266
Nov-19	764	672	266	764
Dec-19	923	952	764	923
Jan-20	916	1,120	923	916
Feb-20	822	962	916	822
Mar-20	595	805	822	595
Apr-20	488	414	595	488
May-20	217	164	488	217
Jun-20	13	30	217	13
Jul-20	0	0	13	0
Aug-20	0	16	0	0
Sep-20	88	83	0	88
Oct-20	309	350	88	309
Nov-20	507	672	309	507
Dec-20	940	952	507	940
Jan-21	1025	1120	940	1,025
Feb-21	969	962	1,025	969
Mar-21	649	805	969	649
Apr-21	388	414	649	388
May-21	204	164	388	204
Jun-21	12	30	204	12
Jul-21	0	0	12	0
Aug-21	0	16	0	0
Sep-21	53	83	0	53
Oct-21		350	53	0
Nov-21		672	0	0
Dec-21		952	0	0
Jan-22		1120	0	0
Feb-22		962	0	0
Mar-22		805	0	0
Apr-22		414	0	0
May-22		164	0	0
Jun-22		30	0	0
Jul-22		0	0	0
Aug-22		16	0	0
Sep-22		83	0	0
Oct-22		350	0	0
Nov-22		672	0	0
Dec-22		952	0	0
Jan-23		1120	0	0
Feb-23		962	0	0
Mar-23		805	0	0
Apr-23		414	0	0
May-23		164	0	0
Jun-23		30	0	0
Jul-23		0	0	0
Aug-23		16	0	0
Sep-23		83	0	0
Oct-23		350	0	0
Nov-23		672	0	0
Dec-23		952	0	0
Jan-24		1120	0	0
Feb-24		962	0	0
Mar-24		805	0	0

	ACT UPC CH Including N, NT, DS
Jul-18	12.0690
Aug-18	12.6686
Sep-18	15.6520
Oct-18	32.3715
Nov-18	63.6875
Dec-18	83.4083
Jan-19	106.7682
Feb-19	85.8784
Mar-19	78.0083
Apr-19	34.7570
May-19	20.1135
Jun-19	13.1592
Jul-19	12.3218
Aug-19	13.0925
Sep-19	12.0927
Oct-19	25.2767
Nov-19	69.3271
Dec-19	75.1481
Jan-20	88.8618
Feb-20	83.0145
Mar-20	59.8374
Apr-20	33.7477
May-20	19.1270
Jun-20	10.9674
Jul-20	10.5768
Aug-20	9.6913
Sep-20	12.7037
Oct-20	25.0362
Nov-20	48.7097
Dec-20	77.3301
Jan-21	95.2403
Feb-21	88.3085
Mar-21	62.7209
Apr-21	36.3264
May-21	21.1221
Jun-21	12.1406
Jul-21	12.2479
Aug-21	12.4521
Sep-21	13.0197

Regression Results:	7.760511177	Constant
	0.006356234	HDD-1
	0.074426343	HDD

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)		1 Month UPC	12 Months Ended UPC
Oct-12	350	83		34.3373	34.3373
Nov-12	672	350		59.9997	94.3370
Dec-12	952	672		82.8858	177.2228
Jan-13	1,120	952		97.1692	274.3919
Feb-13	962	1,120		86.4776	360.8696
Mar-13	805	962		73.7884	434.6580
Apr-13	414	805		43.6898	478.3478
May-13	164	414		22.5979	500.9457
Jun-13	30	164		11.0357	511.9814
Jul-13	0	30		7.9512	519.9326
Aug-13	16	0		8.9513	528.8839
Sep-13	83	16	FY 13	14.0396	542.9235
Oct-13	350	83		34.3373	542.9235
Nov-13	672	350		59.9997	542.9235
Dec-13	952	672		82.8858	542.9235
Jan-14	1,120	952		97.1692	542.9235
Feb-14	962	1,120		86.4776	542.9235
Mar-14	805	962		73.7884	542.9235
Apr-14	414	805		43.6898	542.9235
May-14	164	414		22.5979	542.9235
Jun-14	30	164		11.0357	542.9235
Jul-14	0	30		7.9512	542.9235
Aug-14	16	0		8.9513	542.9235
Sep-14	83	16	FY 14	14.0396	542.9235
Oct-14	350	83		34.3373	542.9235
Nov-14	672	350		59.9997	542.9235
Dec-14	952	672		82.8858	542.9235
Jan-15	1,120	952		97.1692	542.9235
Feb-15	962	1,120		86.4776	542.9235
Mar-15	805	962		73.7884	542.9235
Apr-15	414	805		43.6898	542.9235
May-15	164	414		22.5979	542.9235
Jun-15	30	164		11.0357	542.9235
Jul-15	0	30		7.9512	542.9235
Aug-15	16	0		8.9513	542.9235
Sep-15	83	16	FY 15	14.0396	542.9235
Oct-15	350	83		34.3373	542.9235
Nov-15	672	350		59.9997	542.9235
Dec-15	952	672		82.8858	542.9235
Jan-16	1,120	952		97.1692	542.9235
Feb-16	962	1,120		86.4776	542.9235
Mar-16	805	962		73.7884	542.9235
Apr-16	414	805		43.6898	542.9235
May-16	164	414		22.5979	542.9235
Jun-16	30	164		11.0357	542.9235
Jul-16	0	30		7.9512	542.9235
Aug-16	16	0		8.9513	542.9235
Sep-16	83	16	FY 16	14.0396	542.9235
Oct-16	350	83		34.3373	542.9235
Nov-16	672	350		59.9997	542.9235
Dec-16	952	672		82.8858	542.9235
Jan-17	1,120	952		97.1692	542.9235
Feb-17	962	1,120		86.4776	542.9235
Mar-17	805	962		73.7884	542.9235
Apr-17	414	805		43.6898	542.9235
May-17	164	414		22.5979	542.9235
Jun-17	30	164		11.0357	542.9235
Jul-17	0	30		7.9512	542.9235
Aug-17	16	0		8.9513	542.9235
Sep-17	83	16	FY 17	14.0396	542.9235
Oct-17	350	83		34.3373	542.9235
Nov-17	672	350		59.9997	542.9235
Dec-17	952	672		82.8858	542.9235
Jan-18	1,120	952		97.1692	542.9235
Feb-18	962	1,120		86.4776	542.9235
Mar-18	805	962		73.7884	542.9235
Apr-18	414	805		43.6898	542.9235
May-18	164	414		22.5979	542.9235
Jun-18	30	164		11.0357	542.9235
Jul-18	0	30		7.9512	542.9235
Aug-18	16	0		8.9513	542.9235
Sep-18	83	16	FY 18	14.0396	542.9235

Regression Results:	7.760511177	Constant
	0.006356234	HDD-1
	0.074426343	HDD

	Normal Degree Days (HDD)	Normal Degree Days for Prior Month (HDD-1)		1 Month UPC	12 Months Ended UPC	
Oct-18	350	83		34.3373	542.9235	
Nov-18	672	350		59.9997	542.9235	
Dec-18	952	672		82.8858	542.9235	
Jan-19	1,120	952		97.1692	542.9235	
Feb-19	962	1,120		86.4776	542.9235	
Mar-19	805	962		73.7884	542.9235	
Apr-19	414	805		43.6898	542.9235	
May-19	164	414		22.5979	542.9235	
Jun-19	30	164		11.0357	542.9235	
Jul-19	0	30		7.9512	542.9235	
Aug-19	16	0		8.9513	542.9235	
Sep-19	83	16	FY 19	14.0396	542.9235	
Oct-19	350	83		34.3373	542.9235	
Nov-19	672	350		59.9997	542.9235	
Dec-19	952	672		82.8858	542.9235	
Jan-20	1,120	952		97.1692	542.9235	
Feb-20	962	1,120		86.4776	542.9235	
Mar-20	805	962		73.7884	542.9235	
Apr-20	414	805		43.6898	542.9235	
May-20	164	414		22.5979	542.9235	
Jun-20	30	164		11.0357	542.9235	
Jul-20	0	30		7.9512	542.9235	
Aug-20	16	0		8.9513	542.9235	
Sep-20	83	16	FY 20	14.0396	542.9235	
Oct-20	350	83		34.3373	542.9235	
Nov-20	672	350		59.9997	542.9235	
Dec-20	952	672		82.8858	542.9235	
Jan-21	1,120	952		97.1692	542.9235	
Feb-21	962	1,120		86.4776	542.9235	
Mar-21	805	962		73.7884	542.9235	
Apr-21	414	805		43.6898	542.9235	
May-21	164	414		22.5979	542.9235	
Jun-21	30	164		11.0357	542.9235	
Jul-21	0	30		7.9512	542.9235	
Aug-21	16	0		8.9513	542.9235	
Sep-21	83	16	FY21	14.0396	542.9235	
Oct-21	350	83		34.3373	542.9235	
Nov-21	672	350		59.9997	542.9235	
Dec-21	952	672		82.8858	542.9235	
Jan-22	1,120	952		97.1692	542.9235	
Feb-22	962	1,120		86.4776	542.9235	
Mar-22	805	962		73.7884	542.9235	Historic Test Year Annualized FY 21
Apr-22	414	805		43.6898	542.9235	
May-22	164	414		22.5979	542.9235	
Jun-22	30	164		11.0357	542.9235	
Jul-22	0	30		7.9512	542.9235	
Aug-22	16	0		8.9513	542.9235	
Sep-22	83	16	FY22	14.0396	542.9235	
Oct-22	350	83		34.3373	542.9235	
Nov-22	672	350		59.9997	542.9235	
Dec-22	952	672		82.8858	542.9235	
Jan-23	1,120	952		97.1692	542.9235	
Feb-23	962	1,120		86.4776	542.9235	
Mar-23	805	962		73.7884	542.9235	Future Test Year Annualized FY 22
Apr-23	414	805		43.6898	542.9235	
May-23	164	414		22.5979	542.9235	
Jun-23	30	164		11.0357	542.9235	
Jul-23	0	30		7.9512	542.9235	
Aug-23	16	0		8.9513	542.9235	
Sep-23	83	16	FY23	14.0396	542.9235	
Oct-23	350	83		34.3373	542.9235	
Nov-23	672	350		59.9997	542.9235	
Dec-23	952	672		82.8858	542.9235	
Jan-24	1,120	952		97.1692	542.9235	
Feb-24	962	1,120		86.4776	542.9235	
Mar-24	805	962		73.7884	542.9235	Fully Projected Future Test Year Annualized FY 23

Combined Class CH Incl N, NT and DS
UPC History 10/12-9/21

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.987222809
R Square	0.974608874
Adjusted R Square	0.974125234
Standard Error	5.312361206
Observations	108

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	113739.9144	56869.95719	2015.151528	1.76118E-84
Residual	105	2963.224066	28.22118158		
Total	107	116703.1384			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	7.760511177	0.786698478	9.864657672	1.23403E-16	6.200633419	9.320388935	6.200633419	9.320388935
X Variable 1	0.006356234	0.002179102	2.916904702	0.004323825	0.002035477	0.010676992	0.002035477	0.010676992
X Variable 2	0.074426343	0.002179674	34.14563089	1.13457E-58	0.070104452	0.078748234	0.070104452	0.078748234

SDR-RR-12

Request:

In the form identical to the previous question, please provide a database for all independent variables which were analyzed by the Company, but exclude from the filed gas demand models.

Response:

None.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-13

Request:

For each customer receiving service at less than the maximum applicable tariff rate, please provide:

a. actual consumption for the two most recent calendar years;

b. actual consumption for the HTY and the most recent twelve month period for which data is available;

c. the currently applicable rate;

d. an explanation for the rate discount.

Response:

None.

Prepared by or under the supervision of: Sherry A. Epler

SDR-RR-14

Request:

Please provide a copy of the Company's detailed capital budgets for the preceding and current calendar years which underlie the projected test year capital additions in this case.

Response:

Please see the response to SDR-ROR-14.

Prepared by or under the supervision of: Vicky A. Schappell

SDR-RR-15

Request:

Please provide a variance or other similar report comparing actual and budgeted construction expenditures at the conclusion of each budget period for the past three years and as of the most recent date available.

Response:

Please see Attachment SDR-RR-15.

Prepared by or under the supervision of: Vicky A. Schappell

UGI UTILITIES, INC. – GAS DIVISION
CAPITAL EXPENDITURES – BUDGET VS. ACTUAL
FOR THE YEARS ENDED SEPTEMBER 30, 2019 THROUGH SEPTEMBER 30, 2021
(thousands of dollars)

	09/30/2019	09/30/2020	09/30/2021
Budgeted Expenditures	$ 362,855	$ 394,098	$ 420,100
Actual Expenditures	337,633	336,312	374,066
Variance	$ (25,222)	$ (57,786)	$ (46,034)

SDR-RR-16

Request:

Please provide a breakdown of other gas revenue for the three preceding calendar years.

Response:

Please see Attachment SDR-RR-16. The other operating revenue is shown net of the Company's share of off-system sales, capacity releases, and choice supplier fees.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Other Gas Revenues
For the Years Ended September 30, 2019, 2020, 2021

(000)'s

Account No.		9/30/2019	9/30/2020	9/30/2021
495001	Miscellaneous Gas Revenues*	$ (5,548)	$ (241)	$ 580
495002	Interest on Deferred Fuel Over/Under Collection	$ 1,223	$ 71	$ 615
495003	Interest on Supplier Refund	$ 49	$ 63	$ 541
495004	POR Administrative Fees	$ 66	$ 74	$ 78
		$ (4,211)	$ (33)	$ 1,813

* Miscellaneous Gas Revenues consists of TCJA adjustments, other Miscellaneous Gas Revenues excluded as not applicable for rate making purposes

SDR-RR-17

Request:

For those items for which data is available, please provide the following actual monthly balance by account for the historic and future test periods to present:

a. depreciable utility plant in service
b. non-depreciable utility plan in service
c. construction work in progress
d. accumulated deferred income tax
e. materials and supplies
f. customer advances for construction
g. contributions in aid of construction
h. accumulated depreciation
i. prepayments by type
j. customer deposits
k. injury and damages reserve

Response:

Please refer to Attachment SDR-RR-17.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC. - GAS DIVISION
Actual Ending Balances *(in Thousands)*
For the Months Ended October 31, 2020 through October 31, 2021

	Account Description	Oct 2020	Nov 2020	Dec 2020	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021
a)	Depreciable Plant	3,922,300	3,941,696	3,972,143	3,982,606	3,991,247	4,003,307	4,031,802	4,071,284	4,091,532	4,146,583	4,155,630	4,228,374	4,255,050
b)	Non-Depreciable Plant	27,520	27,528	27,533	27,538	27,542	27,544	27,548	27,572	27,551	27,718	27,744	30,839	30,874
c)	Construction Work in Progress	76,271	76,530	75,541	82,351	87,280	95,485	96,702	94,220	108,679	113,191	101,936	70,852	66,714
d)	Accumulated Deferred Income Tax	(438,499)	(441,312)	(442,902)	(444,673)	(448,258)	(457,184)	(459,444)	(462,570)	(468,152)	(472,638)	(479,349)	(483,952)	(479,775)
e)	Materials and Supplies	15,001	15,305	16,991	14,991	15,281	16,618	15,547	15,494	16,342	15,494	15,377	15,109	15,521
f)	Customer Advances	-	-	-	-	-	-	-	-	-	-	-	-	-
g)	Contributions in Aid of Construction	**Not applicable, as capital expenditures are shown net of any anticipated amounts for CIAC.**												
h)	Accumulated Depreciation	(1,131,483)	(1,138,980)	(1,144,344)	(1,149,968)	(1,156,639)	(1,163,633)	(1,169,797)	(1,176,844)	(1,182,730)	(1,190,513)	(1,191,752)	(1,193,660)	(1,201,591)
i)	Prepayment by Type													
	Prepaid Taxes	316	278	242	237	274	304	272	267	226	376	515	448	384
	PUC Annual Assessment	1,877	1,642	1,408	1,173	939	704	469	235	-	-	-	2,636	2,343
	Prepaid IT Services	4,596	4,487	4,150	5,846	6,639	5,885	5,172	4,812	4,443	4,831	5,326	4,794	4,943
	Miscellaneous	7,332	7,659	10,741	9,944	6,929	5,345	5,242	4,846	4,273	6,517	5,232	4,717	4,442
j)	Gas Customer Deposits	(22,373)	(22,331)	(22,118)	(21,930)	(21,816)	(21,634)	(21,386)	(21,040)	(20,863)	(20,873)	(20,930)	(21,120)	(21,290)
k)	Injury and Damage Reserve	(1,573)	(450)	(2,037)	(2,031)	(1,963)	(1,972)	(1,933)	(1,932)	(1,957)	(1,706)	(1,670)	(1,668)	(1,739)

SDR-RR-18

Request:

Please provide a copy of all work papers supporting the Company's lead/lag study.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedule C-4, and the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 3.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-19

Request:

Please provide the payroll distribution showing the percentage of wages charged to O&M and other categories for each of the preceding three calendar years and the most recent annual period available.

Response:

Please see Attachment SDR-RR-19.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Annual Payroll Data
For the Years Ended September 30, 2019 through 2021
(thousands of dollars)

	12 Months 9/30/2019	**12 Months 9/30/2020**	**12 Months 9/30/2021**
Operations and Maintenance	$ 70,221	$ 73,019	$ 70,423
Other Income/Expense	258	251	340
Capital	42,984	43,373	48,722
Other Non-Expense	6,539	6,178	6,679
Total	$ 120,002	$ 122,822	$ 126,164
Percentage Charged to O&M	58.6%	59.5%	55.9%
Percentage Charged to Other Income/Expense	0.2%	0.2%	0.3%
Percentage Charged to Capital	35.8%	35.3%	38.6%
Percentage Charged to Other Non-Expense	5.4%	5.0%	5.3%

SDR-RR-20

Request:

Please state whether the future test year budgeted labor includes any increases or decreases in the number of employees during the future test year. If increases have been budgeted, please state whether the future test year includes budgeted positions which have not been filled.

Response:

The future test year ("FTY") budgeted labor as of September 30, 2022 includes an increase of 43 regular employees from September 30, 2021 or historic test year ("HTY") budgeted headcount. The fully projected future test year ("FPFTY") labor budget as of September 30, 2023 includes an increase of 27 regular employees from the September 30, 2022 budgeted headcount. While a significant number of the 43 additions during the FTY are still to be filled, the Company is pursuing certain compensation changes which are targeted at increasing retention and recruitment for these and other roles. Please see the Direct Testimony of Christopher R. Brown, UGI Gas Statement No. 1, for additional details.

In addition, please see Exhibit A for the FPFTY Schedules D-9 and D-17 for the details related to the Company's planned addition of 25 FTEs above budgeted levels.

Prepared by or under the supervision of: Christopher R. Brown

SDR-RR-21

Request:

Please explain how the Company has treated routine or normal position vacancies which occur as a result of terminations or retirements in its budgeted labor projections.

Response:

As a Company, during the budgeting process each year, all currently open positions are reviewed to determine if they should be excluded or carried forward into the upcoming budget year. In addition to reviewing individual open positions, vacancy rates are also reviewed across the various functional groups throughout the organization. An overall vacancy rate is then built into the Company labor budget, thereby reducing total budgeted headcounts and associated expenses to take these vacancies into account. This is reflected in both the Future Test Year and the Fully Projected Future Test Year labor projections.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-22

Request:

Please provide the most recent insurance premiums for each type of insurance coverage (i.e., employee benefit and those purchased by the Company) reflected in the Company's filing. If available, please provide estimated premiums for the subsequent calendar year.

Response:

Please refer to Attachment SDR-RR-22 for fiscal 2021 actual and budgeted fiscal 2022 insurance premiums.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
Insurance Premiums Paid & Expected Premiums
For the 12 Months Ending September 30,

	2021	2022
Excess Liability	$ 4,229,656	$ 4,335,398
Property	266,318	275,906
WC Premium	319,470	323,463
Auto Premium	182,733	187,301
GL Premium	4,534	4,592
D&O	413,549	423,888
Crime	29,885	30,613
Cyber	147,603	395,005
Other- aviation	506	512
Fiduciary	94,543	98,088
Employment Practices	48,962	50,186
Medical	13,693,589	13,536,811
Dental - United Concordia	642,125	542,796
Basic Life - Metlife	154,873	180,986
Long Term Disability - Lincoln	363,374	378,286
Accidental Death & Dismemberment	25,454	30,117
Business Travel Accident	27,390	28,131
Total	$ 20,644,565	$ 20,822,079

SDR-RR-23

Request:

Please provide a copy of the Company's two most recent FERC Form 2.

Response:

UGI Utilities, Inc. - Gas Division is not required to file and has not filed a FERC Form 2.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-24

Request:

Please provide a description of each employee benefit program or plan.

Response:

Please see Attachment SDR-RR-24.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. – Gas Division
Benefit Program Effective Jan. 1, 2022

Employee Medical Plan

All employees and their dependents have the option to participate in a health care program that provides four options: an Aetna Point of Service II Plan, an Independence Blue Cross Preferred Provider Option Plan, Aetna High Deductible Health Plan with a Health Savings Account, and an Independence BlueCross High Deductible Plan with a Health Savings Account. Employees share in the cost of medical and prescription plans.

A brief summary of each is listed below:

MEDICAL	**Aetna Choice POS II**		**Independence Blue Cross PPO**	
	In Network	Out of Network	In Network	Out of Network
Deductible	Individual: $600 Family: $1,500	Individual: $1,200 Family: $3,000	Individual: $600 Family: $1,500	Individual: $1,200 Family: $3,000
HSA Annual Funding	N/A	N/A	N/A	N/A
Office Visit Co-Pay PCP/Specialist	$25/$40	70% after deductible	$25/$40	65% after deductible
Co-Insurance after Deductible	85%	65%	85%	65%

MEDICAL	**Aetna HAP/HSA**		**Independence Blue Cross HDP**	
	In Network	Out of Network	In Network	Out of Network
Deductible	Individual: $2,500 Family: $5,000 (imbedded individual $2,800)	Individual: $3,500 Family: $7,000	Individual: $3,000 Family: $6,000	Individual: $4,000 Family: $8,000
HSA Annual Funding by UGI	Individual: $1,000 Family: $2,000		Individual: $750 Family: $1,500	
Office Visit Co-Pay PCP/Specialist	95% after deductible	75% after deductible	85% after deductible	65% after deductible
Co-Insurance after Deductible	95%	75%	85%	65%

Prescription Drug Coverage	**Aetna Choice POS II & Independence Blue Cross PPO**		**Aetna HDHP/HSA & Independence Blue Cross HDP/HSA**	
	In Network	Out of Network	In Network	Out of Network
Deductible	Individual $175; Family $350		Subject to Medical Plan Deductible	
Retail 30 days	$10 Generic $35 Formulary Brand $50 Non-Formulary Brand	Not Covered	$10 Generic $35 Formulary Brand $50 Non-Formulary Brand	Not Covered
Mail Order 90 days	$25 Generic $87.50 Formulary Brand $125 Non-Formulary	Not Covered	$25 Generic $87.50 Formulary Brand $125 Non-Formulary	Not Covered
Specialty Injectables	$100 copay – 30 day supply	Not Covered	$100 copay – 30 day supply	Not Covered

Dental Plan

All employees have access to the following dental plans:

Benefit – In network	**Basic Dental**	**Buy Up Dental**
Annual Deductible:	$50 Individual/$150 Family	No deductible
Diagnostic and Preventive, to include cleanings, fluoride treatments, sealants, x- rays	100%; no deductible	100%; no deductible
Basic Restorative, oral surgery, endodontics	80% co-insurance after deductible	90%
Major Restorative, Prosthodontics	50% co-insurance after deductible	60%
Non-Surgical Periodontics	80% co-insurance after deductible	90%
TMJ, Dental Implants, Occlusal Guards	50% co-insurance after deductible	60%
Annual Maximum for covered services	$1,500	$2,500
Orthodontics	50% co-insurance with $1,500 lifetime maximum	50% co-insurance with $2,500 lifetime

The employee only premium for the Basic Dental coverage is paid for by UGI. UGI contributes this same amount for the employee only Buy up Plan. Employees pay full cost for dependent coverage.

Vision Plans

All employees have access to the following vision plans:

Benefit	Vision Base	Vision Buy Up
Exam for glasses	100%	100%
Clear Standard/Single Vision/Bifocal/Blended Bifocal/Trifocal	$20 copay	$20 copay
Custom Progressive Lenses	$95 - $175	$95 - $175
Standard Progressive Lenses	100%	100%
Elective contact lenses in lieu of glasses	Up to $140	Up to $150

Both Vision plans are 100% employee paid.

Flexible Spending Accounts

All employees are eligible to participate in Health Care or Dependent Day Care Spending Accounts. The annual maximum election for a Health Care Account is $2,750 and the minimum is $260. The annual maximum election for the Dependent Day Care is $5,000 and the minimum is $260. Employees who enroll in the Aetna High Deductible Health Plan are eligible for a Limited Scope Heath Care spending account per IRS regulations.

Group Life Insurance

All employees receive company paid basic life in the amount of one times their annual salary (including certain bonuses) rounded to the next highest $1,000. Part-time employees receive $10,000.

Employees may elect additional employee supplemental life insurance of 1, 2, 3, 4, or 5 times annual salary rounded to the nearest $1,000. This coverage is 100% employee paid. Employee may also elect supplemental life insurance for a spouse in amounts from $10,000 to $100,000 in increments of $10,000. Child(ren) life insurance is also optional in amounts of $5,000 or $10,000. Both spouse and child(ren) life insurance are 100% employee paid.

Accidental Death & Dismemberment (AD&D) and Business Travel Accident (BTA) Insurance

All employees are covered under AD&D insurance 24 hours per day, 365 days per year. The maximum benefit is one times annual salary to a maximum of $2 million. Employee may elect Voluntary AD&D at 1, 2, 3, 4, or 5 times salary to a maximum of $6 million. Spouse only equals

50% of employee coverage. Child(ren, only equals 15% of employee coverage; Spouse and Child(ren) equals 40% for Spouse and 10% for Child(ren) of employee coverage.

All voluntary AD&D coverage is paid 100% by employees.

All employees are covered by Business Travel Accident with a maximum benefit of 4 times annual salary to a maximum of $2 million.

Additional Voluntary Benefits – Employee paid:

- **Doctor on Demand** – Telemedicine available 7 days a week, 24 hours a day right from a mobile device or computer. Any needed prescriptions are sent to the pharmacy of your choice. Medical and mental health services are available for nominal copays based on the employee's medical plan election. Must be enrolled in one of UGI medical plans.
- **Critical Illness** provides a lump sum payment upon diagnosis of Cancer, Heart Attack, Stroke or Major Organ Transplant. Coverage available: Employee $10,000 or $20,000; Spouse $10,000 or $20,000; Children $5,000 or $10,000.
- **Accident Insurance** provides cash for covered injuries that occur on and off the job. Benefits include emergency room visits, fractures and dislocation, ambulance transportation, intensive care, surgeries, and more.
- **Identify Theft Protection** – Proactive monitoring of traditional and non-traditional credit, reimbursement insurance for up to $1 million in identity theft-related expenses, fully managed resolution services.
- **Hospital Indemnity -** Provides a daily benefit for a covered stay in a hospital, critical care unit or rehabilitation facility. The benefit amount is determined by the type of facility and the number of days the covered individual stays confined in the facility. Employees may elect the High or Low plan and coverage their spouse and/or dependent children.
- **Pet Insurance** – This coverage will reimburse eligible veterinary expenses relating to accidents, illnesses, and injuries for pets, like dogs and cats. There are two levels of coverage, one provides pets with wellness coverage.

Short Term Disability

The Company provides a self-insured pay continuation illness plan for all employees. The percentage of pay continued and the number of weeks at 100% and 50% are based on years of service. Short term disability is available for a maximum of 6 months of disability.

Long Term Disability

Employees who exhaust short term disability benefits are eligible to apply for long term disability which is an insured program. Employees who qualify receive 60% of base monthly income offset by other disability income such as Social Security. Maximum benefit is $20,000 per month. Minimum benefit is the greater of $100 or 10% of the gross disability payment per month.

Savings Plan – 401(k)

All employees are eligible to participate in the deferred savings plan which is a tax qualified 401(k) program. The Plan accepts both before-tax and after-tax contributions up to a combined total of 50% of salary subject to the IRS maximum deferral of $61,000 for 2022. The before-tax maximum is $20,500 for 2022. There is also the option to make deferrals as a Roth. Employees who are age 50 or older may contribute an additional catch up contribution of $6,500 per year. The Company matches before-tax or after-tax contributions at 50% of the first 3% and 25% of the next 3% of salary deferred for those employees who participate in the defined benefit pension plan. Participants are immediately vested in the Company match.

Employees hired on or after January 1, 2009 are eligible for an enhanced company match of 100% of 6% effective January 1, 2019 because they are not eligible for the defined benefit pension plan. Vesting is immediate.

Educational Assistance

Full-time employees with a summary performance rating of “Effective Performance” or higher on their most recent annual review may be eligible to participate in the Company’s tuition reimbursement program for courses offered by approved educational institutions. To be eligible for reimbursement studies selected must be related to some phase of the employee’s current job, or be a direct benefit to the Company’s operation, or be part of a required course for a degree (associates, bachelors or masters) or certificate related to the Company’s operation. PhD programs are excluded.

The Company will reimburse 80% of tuition costs only, excluding the cost of books, supplies and other associated fees at qualified educational institutions. The maximum reimbursement per calendar year is limited to $6,300 for undergraduate courses and $10,000 for graduate level courses. In order to receive reimbursement, the employee must provide evidence of satisfactory completion of the course. For courses with letter grades, “satisfactory completion” is defined as follows:

– a grade of “C” or better for undergraduate classes
– a grade of “B” or better for graduate level classes

UGI financially supports employees to retain certification and/or licensure that is required in their current role; or, to obtain certification/licensure which will increase their knowledge and skills as it relates to their current work responsibilities. Oftentimes a course provides valuable assistance in preparing for a certification/licensure exam. This policy enables financial support for reimbursement of approved courses that prepare those who will take an exam to have a greater opportunity for success. This policy also provides financial support for the renewal/maintenance fees for job-related certification/licensure.

This policy applies to all full-time employees and part-time employees 20 hours or more weekly, with “Effective Performance” or higher on their most recent annual review. For employees who have not yet received formal reviews, supervisor approval of application signifies confirmation of “Effective Performance” to date. The professional certification/licensure must be considered by the Company to be directly related to the employee's current job and must be of direct benefit to the Company's operation unless approved by the departmental Vice President and Human Resources.

Paid Time Off

The Company provides all employees with 10 paid holidays and 3 personal days per calendar year. Employees are provided vacation allowances based on years of service ranging from 3 weeks during the first calendar year of employment on a prorated basis up to 6 weeks after 35 years of service.

Severance Program

Exempt employees, in levels M2 – M6 and P3 – P5 are eligible for a severance allowance of two weeks of compensation for each year of service with a minimum of two months of compensation and a maximum of 12 months of compensation. Severed employees will also receive a lump sum payment equal to the COBRA cost of continued medical and dental coverage for the period of severance less the active employee contribution amount.

Exempt employees, in levels M1, P1 - P2 and non-bargaining non-exempt employees, are eligible for a severance allowance of one week of compensation for each year of service with a minimum of two weeks of compensation and a maximum of 12 months of compensation. Severed employees will also receive a lump sum payment equal to the COBRA cost of continued medical and dental coverage for the period of severance less the active employee contribution amount.

Post-Retirement Benefits

Retirement Plan – UGI Utilities, Inc. Employees Hired Prior to 1/1/2009

The Plan is a noncontributory defined benefit plan covering substantially all employees of UGI Utilities, Inc. hired prior to January 1, 2009. Effective January 1, 2009, the Plan was closed to new hires, rehires or transfers occurring on or after that date.

Substantially all employees of the UGI Employers hired prior to January 1, 2009 who complete five years of vesting service, as defined, or who reach normal retirement age, as defined, while in the employ of the UGI Employers, are entitled to benefits upon reaching normal retirement age, generally age 65.

The annual pension benefits shall generally be the greatest of:

- $600; or

- 1.9% of final average earnings, as defined, times years of credited service, as defined, (which amount cannot exceed 60% of the average monthly earnings for the highest consecutive 12-month period during the 120 consecutive month period prior to the date of retirement or termination), less (b) 1% of the primary Social Security benefit, as defined, times the years of credited service at age 65 (maximum of 35 years) and in the case of early retirement, multiplied further by the ratio of actual credited service to projected credited service at normal retirement date; or

- 25% of earnings during the last 12 months prior to retirement multiplied by the ratio (not to exceed 1.0) of years of projected credited service to normal retirement date to 15, and in the case of early retirement, multiplied further by the ratio (not to exceed 1.0) of years of credited service earned to the projected years of credited service at normal retirement date.

The Plan permits early retirement benefits at a reduced level at age 55 and completion of ten years of vesting service. Unreduced early retirement benefits are available for employees retiring from age 62 to age 65, who have completed 10 years of vesting service

Retirement Plan – UGI Utilities, Inc. Employees That Are Former Non-Union Employees of UGI Central Penn Gas, Inc. Hired Prior to 1/1/2009 or Former Union Employees of UGI Central Penn Gas, Inc. Hired Prior to 1/1/2012

The Plan is a non-contributory defined benefit plan covering employees of UGI Central Penn Gas, Inc. hired prior to January 1, 2009. Effective January 1, 2009, the Plan was closed to new hires, rehires or transfers occurring on or after that date except for employees subject to a collective bargaining agreement. The plan closed for those employees on January 1, 2012.

Substantially all CPG employees of the UGI Employers hired prior to January 1, 2009, or January 1, 2012 for those covered under a collective bargaining unit, who complete five years of vesting service, as defined, or who reach normal retirement age, as defined, while in the employ of the UGI Employers, are entitled to benefits upon reaching normal retirement age, generally age 65.

The annual pension benefits shall generally be:

- 1.08% of average monthly earnings up to covered monthly earnings times years of credited service up to 35 years

  plus

- 1.35% of average monthly earnings that are more than the covered monthly earnings times years of credited service up to 35 years

There is a group of CPG employees whose pension benefits are calculated under a grandfathered pension formula. Their annual pension benefits shall generally be:

- 1.65% of the first $833.34 of monthly earnings, plus 2% of monthly earnings in excess of $833.34 for each year of credited service.

The Plan permits early retirement benefits at a reduced level at age 55 and completion of ten years of vesting service. Unreduced early retirement benefits are available for employees retiring from age 60 to age 65, who have completed 10 years of vesting service

Retirement Plan - UGI Utilities, Inc. Employees That Are Former Employees of UGI Penn Natural Gas, Inc. Hired Prior to 1/1/2009

The Plan is a noncontributory defined benefit plan covering substantially all employees hired prior to January 1, 2009. Effective January 1, 2009, the Plan was closed to new hires, rehires or transfers occurring on or after that date.

Substantially all employees hired prior to January 1, 2009 who complete five years of vesting service, as defined, or who reach normal retirement age, as defined, are entitled to benefits upon reaching normal retirement age, generally age 65.

The annual pension benefits shall generally be:

A. (1.25% of Final Average Earnings up to the Base Amount) times (your years of Credited Service up to 30 years)

Plus

B. (1.65% of Final Average Earnings over the Base Amount) times (your years of Credited Service up to 30 years)

in no event will the benefit be less than the ratio of years of Credited Service (maximum of 30) divided by 30 and multiplied by $1,800.

The Plan permits early retirement benefits at a reduced level at age 55 and completion of 10 years of vesting service. Unreduced early retirement benefits are available for employees retiring from age 62 to age 65, who have completed 10 years of vesting service.

Retiree Life Insurance

Pension-eligible employees who retire are eligible for retiree life insurance in the amount of 25% of their pre-retirement amount with a maximum coverage amount of $50,000. There is no cost to the retiree.

Retiree Medical Insurance - UGI Utilities, Inc. Employees

An eligible employee is any full-time employee of UGI Utilities, Inc. who as of January 1, 1989, was at least 55 years of age and had completed at least 10 years of service with UGI or an affiliated corporation or whose age and years of service equaled at least 80 and who immediately following his retirement from UGI commences receipt of an early, normal or late retirement pension.

Effective January 1, 2014, retiree medical for Medicare-eligible retirees (age 65 or over) was outsourced to a third party and the benefit was changed to a health reimbursement account. In addition, the Retiree Plan covers Medicare-eligible disabled employees who are receiving long term disability benefits. Retirees and spouses who retired on or after 1/1/1986 receive $500 per calendar year and those who retired prior to 1/1/1986 receive $700 per calendar year.

Retiree Medical Insurance -UGI Utilities, Inc. Employees Previously Employed by UGI Central Penn Gas, Inc.

- Any employees who previously retired from the employment of UGI Central Penn Gas, Inc. (or a predecessor employer ("CPG") before the October 1, 2008 acquisition of CPG by UGI, an Eligible Retired Employee shall mean: any retired employee who was at least 55 years of age, had completed at least 10 years of service with CPG, had retired and commenced receipt of his retirement pension under the PPL Gas Retirement Plan immediately following his retirement from CPG and was receiving benefits under the PPL Gas Retiree Medical Plan as of October 1, 2008.

- Any full-time employees of CPG who retired from the employment of CPG on or after the October 1, 2008 acquisition of CPG by UGI, an Eligible Retired Employee shall mean: any full-time employee of CPG who is at least 55 years of age, has completed at least 10 years of service with CPG, retires and commences receipt of his retirement pension under the PPL Gas Retirement Plan immediately following his retirement from CPG and retired from CPG on or after the October 1, 2008 acquisition of CPG by the Company, but on or before January 1, 2009;

- Any full-time employee who was covered under the terms of a collective bargaining agreement between a collective bargaining representative and CPG and who is at least 55 years of age, has completed 10 years of service with CPG and retired prior to January 1, 2012.

Effective January 1, 2014, retiree medical for Medicare-eligible retirees (age 65 or over) was outsourced to a third party and the benefit was changed to a health reimbursement account. In addition, the Retiree Plan covers Medicare-eligible disabled employees who are receiving long term disability benefits. Retirees and spouses who retired on or after 1/1/1986 receive $500 per calendar year.

Retiree Medical Insurance -UGI Utilities, Inc. Employees Previously Employed by UGI Penn Natural Gas, Inc.

No employees of the former UGI Penn Natural Gas, Inc. are eligible for retiree medical.

SDR-RR-25

Request:

Please provide a description of the Company's merit and cost of living wage rate increase policies.

Response:

The Company does not provide wage adjustments based on changes in the cost of living index.

Non-Union Employees:

The Company maintains a salary structure which is comprised of salary grades and ranges. All non-union positions are assigned a salary range based on the competitive value of the job. The salary structure is reviewed periodically and adjusted, at the discretion of management, to remain externally competitive and internally equitable in order to attract, motivate, and retain quality employees.

Funds are budgeted each year for merit increases based on prevailing market rates. Performance reviews are scheduled annually with employees. Merit increase guidelines are established and individual performance ratings determine individual merit increases. Please see Attachment SDR-RR-25.

Union Employees:

Employees who are represented by bargaining units are paid according to the rates negotiated in their labor agreements.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC.
MERIT INCREASE POLICY
FOR FISCAL YEAR 2022

Date: September 14, 2021

To: All Utilities Leaders

From:

Subject: **UGI Utilities, Inc. Exempt & Non-Exempt Compensation Plan**
Fiscal 2022 Salary Ranges, Merit Increase Grids & Guidelines

We have completed the annual review of compensation practices, merit, and structure trends, and general business economic indicators of our competitive marketplace, as well as current business conditions throughout UGI. The following guidelines will apply to exempt (salaried) and non-exempt (hourly paid) employees effective September 27, 2021.

Changes for Fiscal Year 2022

- Salary Ranges: Exempt and non-exempt pay ranges will shift upward by 2%
- Merit Increase Grids: For exempt and non-exempt employees, grids reflect a 3% average merit increase target

Salary Ranges

Each employee may discuss the following with his or her supervisor:

- The salary range minimum, midpoint, and maximum for his or her position
- The current position of his or her salary in their respective salary range expressed in thirds (i.e., first third, middle third, upper third)
- The date of his or her next scheduled performance appraisal and when he or she is next eligible for a merit increase
- The applicable merit increase grids

Merit Increase Period, Proration & Proration for Absence

Exempt Employees:

- The merit increase review period is the fiscal year October 1, 2021 to September 30, 2022, and the merit increase will be provided in December 2022

- For new hires or transfers to an exempt role on/after September 1, 2021, their merit increase/performance review will be deferred to the merit increase cycle for FY 2022 (provided in December 2022)
- If the employee receives promotion on/after October 1, 2021, the merit increase will be based on annual salary as of September 30, 2021
- The merit increase will be prorated based on the time period worked during the fiscal year if you are:
  - Hired after October 1, 2021
  - Transferred from Corporate, Energy Services, or AmeriGas after October 1, 2021
  - Transferred from non-exempt to exempt position after October 1, 2021
- Merit increases will be prorated if an employee is on unpaid leave of absence (excludes FMLA, workers' compensation, and military leave) for 60 or more consecutive days during the fiscal year
- Merit increase will be prorated for the time an employee is on long term disability

Non-exempt employees:

- The merit increase review period is 12 months prior to the merit increase effective date
- Employees that are on unpaid leave of absence (excludes FML, workers' compensation, and military leave) for 60 or more consecutive days will have their next review date adjusted by the number of calendar days on leave

Any employee not actively at work on the effective date of their merit increase, they will receive their earned merit increase retroactive to the effective date in the pay cycle after returning to work and completing their performance review discussion/meeting.

Merit Increase Grid

The exempt and non-exempt increase grids for Fiscal 2022 are attached. The targeted increase percentage is reflected on each grid at the "Effective Performance" level and middle third position in range. These grids comply with the Company's normal salary administration practice which provides for salary increase consideration on a 12-month review cycle.

Performance Level	First Third	Middle Third	Upper Third	At or Above Maximum
Exceptional Performance Percent of Population: 5% - 10%	5.0% - 6.0%	4.0% - 5.0%	3.0% - 4.0%	0 - 2.5% (Lump Sum)
Highly Effective Performance Percent of Population: 10% - 15%	4.0% - 5.0%	3.0% - 4.0%	2.0% - 3.0%	0 - 2.0% (Lump Sum)
Effective Performance Percent of Population: 60% - 65%	3.0% - 4.0%	2.0% - 3.0%	1.0% - 2.0%	0 - 1.0% (Lump Sum)
Not Fully Effective Performance Percent of Population: 10% - 15%	Up to 2.0%	Up to 1.0%	None	None
Unsatisfactory Performance Percent of Population: 0% - 5%	None	None	None	None

Percentage increases based on performance and position of pay within salary range

Below Minimum Guidelines

Employees that fall below the career level salary range minimum are typically eligible for an increase to the career level salary range minimum. Human Resources will review employees in this situation each year and will bring them to your attention.

Promotional Guidelines

Promotional increase guidelines will be 2 to 3 times the targeted average merit increase percentages (e.g., 6.0% to 9.0%).

There are two types of promotions:

1. Promotion: New position is an increase in career level due to change in job responsibilities (increase in scope, complexity, responsibilities, etc.). Usually results in a backfill (additional headcount) of employee's current position.
2. Progression Promotion: A progression is a promotion from one level to the next that has documented criteria which employees need to achieve. This type of promotion does not result in a backfill or additional headcount. Progressions apply to eligible roles in Business Support, Technical Support and Professional career levels. (Example: Customer Care Representative I (B1) progresses to Customer Care Representative II (B2)). Please work with your Human Resources Manager to assess the position and complete a Promotion Criteria & Assessment Document.

Lateral Move

There are two types of lateral moves:
1. Lateral move with comparable responsibility.
    a. Career Framework categories are the same
    b. Very similar team management responsibilities (includes contractors), if applicable
    c. Same complexity of work and/or process
    d. Other responsibilities align (on-call, committee participation, project leadership, geographic scope)
    e. Up to 2% increase if employee's salary falls below the new role's pay range midpoint.
        i. For pay increase, employee needs to be in current role for at least one continuous year
2. Step Change in Responsibility
    a. Career Framework categories are the same or broader
    b. Increased team management responsibilities (includes contractors), if applicable
    c. More complex work, processes, decision-making
    d. Other responsibilities increase, broaden or deepen (on-call, committee participation, project leadership, geographic scope)
    e. Up to 5% increase if employee's salary falls below the new role's pay range midpoint and the position's market midpoint
        i. For pay increase, employee needs to be in current role for at least one continuous year

Move to Lower Career Level

If an employee moves to a position at a lower career level, there will be a pay reduction if the employee's salary falls in the upper third or over the maximum of the new career level. The pay reduction will be 5% per level decrease. If the pay reduction percent does not bring the new rate down to the new career level maximum, the maximum will become the new rate of pay. For example, employee's current position is career level M3 and they are moving to a P2 role. This would be a two-level reduction (M3 -> M2 -> P2) which would result in a 10% base pay reduction if employee's current salary falls in the upper third of the P2 salary range.

Temporary Assignments

For employees that receive job changes due to temporary assignments on special projects, the compensation information on that temporary assignment's offer letter will supersede the guidelines in this memo.

At or Above Maximum Guidelines

- An employee whose pay is at or above the maximum of their career level pay range may receive an increase in a lump sum as shown in the merit grid depending on their performance rating.
- An employee can only receive an increase in base compensation up to the maximum of their career level pay range, and any remaining increase will be paid in a lump sum.

Six Month Interim Performance Appraisal

An interim appraisal every six (6) months is required to review progress for employees who receive an annual performance rating of "Not Fully Effective Performance" or "Unsatisfactory Performance".

The Interim Performance Appraisal should be completed six months after the employee's annual performance appraisal date. For example: An employee receives a "Not Fully Effective Performance" rating at his/her annual review effective December 1st; therefore, an Interim Performance Appraisal is due June 1st. **There is no change in compensation with the Interim Performance Appraisal.**

If you have any questions regarding the above, please feel free to contact me or your local HR representative.

SDR-RR-26

Request:

Please provide the following monthly labor data for the year prior to the HTY, the HTY and the FTY through the most recent date available.

a. number of actual employees broken down between type (e.g., salaried, union, non-union, temporary, etc.);

b. regular payroll broken down between expensed, capitalized and other;

c. overtime payroll broken down between expensed, capitalized and other;

d. temporary payroll broken down between expensed, capitalized and other; and

e. other payroll (specify).

Response:

a. Please see Attachment SDR-RR-26, page 1.

b-c. See Attachment SDR-RR-26, page 2.

d-e. Not available.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION

EMPLOYEE COUNT

12 MONTHS ENDED SEPTEMBER 30, 2020

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Union	658	660	667	667	666	667	663	664	662	665	666	684
Non-Union	946	945	945	954	954	970	971	953	954	950	943	941
Non-Union Temporary	18	22	26	25	23	20	16	19	21	21	17	17
Total	1,622	1,627	1,638	1,646	1,643	1,657	1,650	1,636	1,637	1,636	1,626	1,642

12 MONTHS ENDED SEPTEMBER 30, 2021

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Union	683	677	673	670	672	676	678	674	681	677	676	673
Non-Union	940	941	947	972	979	987	981	988	991	989	995	982
Non-Union Temporary	17	17	16	16	16	14	16	23	32	32	16	12
Total	1,640	1,635	1,636	1,658	1,667	1,677	1,675	1,685	1,704	1,698	1,687	1,667

12 MONTHS ENDED SEPTEMBER 30, 2022

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Union	675	675										
Non-Union	982	985										
Non-Union Temporary	11	11										
Total	1,668	1,671										

UGI UTILITIES, INC. - GAS DIVISION

MONTHLY LABOR DATA
(Thousands of Dollars)

12 MONTHS ENDED SEPTEMBER 30, 2020

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Expense Straight Time	5,168	7,011	3,886	3,811	5,310	6,945	9,347	5,724	4,338	4,868	4,682	6,796
Expense Overtime	428	713	700	694	368	388	279	173	270	343	369	656
Capital Straight Time	3,579	5,112	3,345	2,777	3,702	4,312	4,448	3,550	3,143	3,263	3,936	5,593
Capital Overtime	280	400	180	155	194	207	91	113	196	196	295	484
Total	9,455	13,237	8,111	7,437	9,575	11,853	14,165	9,561	7,947	8,670	9,282	13,529

12 MONTHS ENDED SEPTEMBER 30, 2021

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Expense Straight Time	4,574	5,016	4,461	6,260	5,463	8,606	5,073	5,324	4,981	4,621	4,887	6,007
Expense Overtime	317	348	583	548	372	615	389	349	390	462	429	687
Capital Straight Time	4,481	3,916	3,240	4,129	3,596	6,775	3,904	3,952	4,058	3,976	4,057	6,397
Capital Overtime	214	236	170	170	137	236	205	250	257	269	301	474
Total	9,586	9,516	8,455	11,108	9,568	16,232	9,571	9,875	9,686	9,329	9,674	13,565

12 MONTHS ENDED SEPTEMBER 30, 2022

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Expense Straight Time	4,795	4,853										
Expense Overtime	465	531										
Capital Straight Time	3,937	3,983										
Capital Overtime	307	322										
Total	9,504	9,688										

SDR-RR-27

Request:

Please provide a copy of all incentive compensation and/or bonus plans and provide the level of related payments included in cost of service.

Response:

Information regarding UGI's UNITE Incentive Compensation Plan and UGI's FY22 Management Incentive Plan are confidential and will be made available to parties upon request and the entry of an acceptable Protective Order.

Please refer to Attachments SDR-RR-27.1 through SDR-RR-27.5 contained on the USB flash drive for a copy of all other incentive compensation plans.

The total expense included within the cost of service is $11,129,787 for the Fully Projected Future Test Year.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-28

Request:

Please provide the percentage wage rate increases granted by the Company by date and employee category for the three most recent calendar years and the current year to date.

Response:

Please refer to Attachment SDR-RR-28.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. – Gas Division
Wage Rate Increases
2018 – 2021

Bargaining Unit	2018	2019	2020	2021
System Council U-22 of the IBEW	3.00%	3.00%	2.75%	3.00%
Gas Fitter-Utility Employee Local Union No. 600	3.00%	3.00%	3.00%	2.75%
IBEW Local 2244 (Archbald)	2.75%	3.00%	3.00%	3.00%
IBEW Local 2244 (Honesdale)	3.00%	2.75%	2.75%	2.75%
UWUA Locals 406, 407, 408, 529	2.75%	3.00%	3.00%	3.00%
UWUA Locals 332, 435, 554	3.00%	3.00%	3.00%	2.75%
Teamsters Local 429	3.00%	3.00%	3.00%	2.75%
Teamsters Local 326	3.00%	3.00%	3.00%	2.75%
ICWU/UFCW Local 570	3.00%	3.00%	3.00%	2.75%
Utility Workers Local 2799	3.00%	3.00%	3.00%	2.75%
IBEW Local 1941 (Corrosion Control)	N/A	N/A	N/A	2.75%
IBEW Local 1456 (Operations Support)	N/A	N/A	N/A	2.75%

Future Contractual Increases

Gas Fitter-Utility Employee Local Union No. 600 – 3.00% wage increase 6/1/2022
IBEW Local 2244 (Archbald) – 3.00% wage increase 8/1/2022
IBEW Local 2244 (Honesdale) - 3.00% wage increase 4/1/2022
UWUA Locals 406, 407, 408, 529 – 3.00% wage increase 4/1/2022
UWUA Locals 332, 435, 554 – 3.00% wage increase 7/1/2022
Teamsters Local 429 – 3.00% wage increase 5/1/2022
Teamsters Local 326 – 3.00% wage increase 7/1/2022
ICWU/UFCW Local 570 – 3.00% wage increase 5/16/2022
Utility Workers Local 2799 – 3.00% wage increase 6/2/2022
IBEW Local 1941 (Corrosion Control) – 3.00% wage increase 7/1/2022
IBEW Local 1456 (Operations Support) – 3.00% wage increase 5/1/2022

Non-Union Employees

2018 Actual Merit: 3.57% (exempt = 2.82% nonexempt =3.68%);
2019 Actual Merit: 3.22% (exempt = 3.08% nonexempt =3.24%);
2020 Actual Merit: 3.27% (exempt = 3.23% nonexempt = 3.29%);
2021 YTD Actual Merit: TBD (exempt = TBD nonexempt = 3.25%);

SDR-RR-29

Request:

Please provide an analysis (description, dates and amounts) of any gains or losses on utility property sold for the lesser of the last three years or since the Company's last rate case or anticipated during the FTY. Explain how such amounts have been treated for ratemaking purposes.

Response:

A gain of $51,660 was recorded since the last UGI Gas Base Rate Case.

The UGI Gas West Pittston Pump Station land asset was sold in March 2021. The proceeds of the land sale were $58,410 with an asset value of $6,750 at the sale date, resulting in a gain of $51,660. This gain was recorded to FERC account 421.1 – Gain on Disposition of Property.

We anticipate proceeds on sales of vehicles during the FY2022 (FTY) and FY2023 (FPFTY) of $500,000 each year. For ratemaking purposes, these proceeds are treated as net salvage.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-30

Request:

Please provide the level of each of the following which is included in the Company's cost of service by separate type and/or payee, which are incurred directly by the Company or are allocated or billed to the Company by affiliates or its parent company.

a. fines and penalties

b. contributions and donations

c. membership dues

d. lobbying expense

e. employee activity costs (e.g., picnics, parties, awards)

f. investor relations expenses

Response:

a. No costs for fines and penalties are included.

b. No costs for contributions and donations are included.

c. Please refer to Attachment SDR-RR-30.

d. No lobbying expenses are included.

e. The cost of service includes direct employee activity costs (e.g., picnics, parties, awards) in the amount of $588,226 for the fully projected future test year.

f. The cost of service includes allocated investor relations expenses in the amount of $131,918 for the fully projected future test year.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF COMPANY MEMBERSHIPS
FOR THE YEAR ENDED SEPTEMBER 30, 2023

Organization Name	2023	
Allentown Economic Development Corp.	$ 5,148	
American Gas Association	621,015	*
Association for material protection and performance	1,932	
Cyber Resilient Energy Delivery Consortium	30,480	
Economic Development Co. of Lancaster County	32,964	
Energy Association of Pennsylvania	154,317	**
Energy Solutions Center Inc.	6,225	
Focus Central Pennsylvania Inc.	3,096	
Lebanon Valley Economic Development Corp.	8,244	
Lehigh Valley Economic Development Corp	21,636	
Natural Gas Supply Collaborative	20,000	
Natural Gas Vehicles for America	26,753	
Northeast Gas Association	55,000	
Northeastern Pennsylvania Alliance	1,704	
Penn's Northeast	5,664	
Pennsylvania Chamber of Business & Industry	66,521	
Pennsylvania Economy League	12,117	
Society of Gas Operators	1,863	
The Coalition for renewable natural gas	29,000	
Organizations Under $1,500	11,724	
	$ 1,115,404	

* Of the American Gas Association expense shown for the fully projected future test year, $597,416 will be included in the claim, while $23,599 relates to lobbying activities and will be excluded.

** Of the Energy Association of Pennsylvania expense shown for the fully projected future test year, $145,058 will be included in the claim, while $9,259 relates to lobbying activities and will be excluded.

SDR-RR-31

Request:

Please provide a description and the purpose for membership for each organization listed in the previous response.

Response:

Refer to response SDR-RR-32 for the purpose of memberships in industry organizations. The purpose of the Company's membership in other organizations is to improve the welfare, educational, social and economic climate in the Company's local communities, as well as to sponsor memberships for employees whose active participation in these organizations would be in the best interests of the Company and the communities within which the Company serves.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-32

Request:

Please provide the level of payments made to industry organizations included in cost of service along with a description of each payee organization or project.

Response:

Please refer to Attachment SDR-RR-32 for the industry organization payments included in the cost of service. The description of each payee organization is provided below.

- The American Gas Association (AGA) is a trade association that represents more than 200 local energy companies that deliver clean natural gas throughout the United States.

- The Cyber Resilient Energy Delivery Consortium (CREDC) performs multidisciplinary R&D in support of the Energy Sector Control Systems Working Group's Roadmap of resilient Energy Delivery Systems (EDS) that focuses on the cybersecurity of EDS.

- The Energy Association of Pennsylvania (EAP) is a trade association whose members include the electric and natural gas utilities operating in Pennsylvania.

- The Energy Solutions Center, Inc. (ESC) is a non-profit organization of energy utilities and equipment manufacturers that promotes energy efficient natural gas solutions and systems for use by residential, commercial, and industrial energy users.

- The Natural Gas Supply Collaborative (NGSC) is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for natural gas supply.

- The Natural Gas Vehicles for America (NGVAmerica) is a national organization dedicated to the development of a growing, profitable, and sustainable market for vehicles powered by natural gas or biomethane.

- The Northeast Gas Association (NGA) is a regional trade association that focuses on education and training, technology research and development, operations, planning, and increasing public awareness of natural gas in the Northeast U.S.

SDR-RR-32 (Continued)

- The Society of Gas Lighting is a group of over 100 industry executives from the Northeast and Mid-Atlantic states that meet to engage fellow members, and their guests, in discussion about the issues of the day as they may affect the development, transmission or distribution of natural gas.

- The Society of Gas Operators is an Industry group focusing on the sharing of information and topics relevant to Gas Operations. Membership is predominantly from gas companies and suppliers in the Northeast United States.

- The Coalition for Renewable Natural Gas (RNG Coalition) serves as the public policy advocate and education platform for Renewable Natural Gas in North America.

Prepared by or under the supervision of: Tracy A. Hazenstab

UGI UTILITIES, INC. - GAS DIVISION
SCHEDULE OF INDUSTRY ORGANIZATION PAYMENTS
FOR THE TWELVE MONTHS ENDING SEPTEMBER 30, 2023

Organization Name	**Included in Claim**	**Excluded from Claim***	**Total Payment**
American Gas Association	$ 597,416	$ 23,599	$ 621,015
Cyber Resilient Energy Delivery Consortium	30,480	-	30,480
Energy Association of Pennsylvania	145,058	9,259	154,317
Energy Solutions Center Inc.	6,225	-	6,225
Natural Gas Supply Collaborative	20,000	-	20,000
Natural Gas Vehicles for America	26,753	-	26,753
Northeast Gas Association	55,000	-	55,000
Society of Gas Lighting	1,257	-	1,257
Society of Gas Operators	1,863	-	1,863
The Coalition for Renewable Natural Gas	29,000	-	29,000
	$ 913,052	$ 32,858	$ 945,910

* Expenses related to lobbying activities have been excluded from the cost of service.

SDR-RR-33

Request:

Please provide the following information related to the Company's membership in AGA:

a. Cost included in requested cost of service.

b. Cost excluded from requested cost of service.

c. Copy of the most recent audit report of AGA expenditures prepared by NARUC.

d. Most recent correspondence received from AGA which addresses the percentage of dues related to lobbying or other separate activities.

e. Policy statement, objective, purpose, etc. of AGA.

Response:

a. The cost of service includes membership fees paid to AGA in the amounts of $563,094 for historic, $580,015 for future and $597,416 for fully projected future test years, respectively.

b. The cost of service excludes membership fees paid to AGA for lobbying activities in the amounts of $22,243 for historic, $22,911 for future and $23,599 for fully projected future test years, respectively.

c. NARUC last performed an audit of AGA expenditures in 2002, for which the audit report has been provided in Attachment SDR-RR-33.c.

d. Please refer to Attachment SDR-RR-33.d.

e. Please refer to Attachment SDR-RR-33.e.

Prepared by or under the supervision of: Tracy A. Hazenstab

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 2002

March 2005

NARUC STAFF SUBCOMMITTEE
ON ACCOUNTING AND FINANCE

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005

N A R U C
National Association of Regulatory Utility Commissioners

March 2005

To: **The State Regulatory Commissions**

From: **The NARUC Staff Subcommittee on Accounting and Finance**

Re: **Transmittal of the 2002 Report on the Expenditures of the American Gas Association**

Dear State Regulatory Commissions:

This is the annual report on the expenditures of the American Gas Association (AGA) provided for your review and consideration. Hopefully you will find the information contained herein to be useful in helping you to decide which, if any, of the costs of the association you should approve for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities.

With the possible exception of expenses directly related to research and development relevant to utility operations, and a proportional amount of associated administrative overhead expense, these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit.

The Staff Subcommittee on Accounting and Finance is pleased to provide you with the AGA report for 2002 to allow you to review the information contained therein and to utilize it in a manner consistent with your commission's regulatory policies and practices.

Sincerely,

Thomas J. Ferris

Thomas J. Ferris
Chair
Staff Subcommittee on Accounting and Finance

Calculation of Lobbying Expenses Pursuant to
Internal Revenue Code Section 162(e)

The American Gas Association incurred lobbying expenses, as defined under IRC Section 162, of 2.28% of total member dues during calendar year 2002.

IRC Section 162 Definition of Lobbying

(e) Denial of deduction for certain lobbying and political expenditures
- (1) In general no deduction shall be allowed under subsection (a) for any amount paid or incurred in connection with -
  - (A) influencing legislation,
  - (B) participation in, or intervention in, any political campaign on behalf of (or in opposition to) any candidate for public office,
  - (C) any attempt to influence the general public, or segments thereof, with respect to elections, legislative matters, or referendums, or
  - (D) any direct communication with a covered executive branch official in an attempt to influence the official actions or positions of such official.
- (2) Exception for local legislation - In the case of any legislation of any local council or similar governing body -
  - (A) paragraph (1)(A) shall not apply, and
  - (B) the deduction allowed by subsection (a) shall include all ordinary and necessary expenses (including, but not limited to, traveling expenses described in subsection (a)(2) and the cost of preparing testimony) paid or incurred during the taxable year in carrying on any trade or business -
    - (i) in direct connection with appearances before, submission of statements to, or sending communications to the committees, or individual members, of such council or body with respect to legislation or proposed legislation of direct interest to the taxpayer, or
    - (ii) in direct connection with communication of information between the taxpayer and an organization of which the taxpayer is a member with respect to any such legislation or proposed legislation which is of direct interest to the taxpayer and to such organization, and that portion of the dues so paid or incurred with respect to any organization of which the taxpayer is a member which is attributable to the expenses of the activities described in clauses (i) and (ii) carried on by such organization.
- (3) Application to dues of tax-exempt organizations - No deduction shall be allowed under subsection (a) for the portion of dues or other similar amounts paid by the taxpayer to an organization which is exempt from tax under this subtitle which the organization notifies the taxpayer under section 6033(e)(1)(A)(ii) is allocable to expenditures to which paragraph (1) applies.
- (4) Influencing legislation - For purposes of this subsection -
  - (A) In general The term "influencing legislation" means any attempt to influence any legislation through communication with any member or employee of a legislative body, or with any government official or employee who may participate in the formulation of legislation.
  - (B) Legislation - The term "legislation" has the meaning given such term by section 4911(e)(2).
- (5) Other special rules
  - (A) Exception for certain taxpayers - In the case of any taxpayer engaged in the trade or business of conducting activities described in paragraph (1), paragraph (1) shall not apply to expenditures of the taxpayer in conducting such activities directly on behalf of another person (but shall apply to payments by such other person to the taxpayer for conducting such activities).
  - (B) De minimis exception
    - (i) In general Paragraph (1) shall not apply to any in-house expenditures for any taxable year if such expenditures do not exceed $2,000. In determining whether a taxpayer exceeds the $2,000 limit under this clause, there shall not be taken into account overhead costs otherwise allocable to activities described in paragraphs (1)(A) and (D).
    - (ii) In-house expenditures for purposes of clause (i), the term "in-house expenditures" means expenditures described in paragraphs (1)(A) and (D) other than
      - (I) payments by the taxpayer to a person engaged in the trade or business of conducting activities described in paragraph (1) for the conduct of such activities on behalf of the taxpayer, or
      - (II) dues or other similar amounts paid or incurred by the taxpayer which are allocable to activities described in paragraph (1).
  - (C) Expenses incurred in connection with lobbying and political activities - Any amount paid or incurred for research for, or preparation, planning, or coordination of, any activity described in paragraph (1) shall be treated as paid or incurred in connection with such activity.
- (6) Covered executive branch official - For purposes of this subsection, the term "covered executive branch official" means -
  - (A) the President,
  - (B) the Vice President,
  - (C) any officer or employee of the White House Office of the Executive Office of the President, and the 2 most senior level officers of each of the other agencies in such Executive Office, and
  - (D) (i) any individual serving in a position in level I of the Executive Schedule under section 5312 of title 5, United States Code, (ii) any other individual designated by the President as having Cabinet level status, and (iii) any immediate deputy of an individual described in clause (i) or (ii).
- (7) Special rule for Indian tribal governments - For purposes of this subsection, an Indian tribal government shall be treated in the same manner as a local council or similar governing body.
- (8) Cross reference - For reporting requirements and alternative taxes related to this subsection, see section 6033(e).

Citation: IRC Sec. 6033(e)

AMERICAN GAS ASSOCIATION

Table of Contents

Report of American Gas Association Financial Operations
In accordance with agreement between
American Gas Association and NARUC Oversight Committee

For the Year Ended December 31, 2002

Internal Revenue Service Form 990

The American Gas Association is a non-profit and tax exempt organization required to file informational returns with the U.S. Internal Revenue Service (IRS). Public inspection of the completed American Gas Association Exempt Organization Return (IRS Form 990) may be made in accordance with IRS regulation by request directly to the Internal Revenue Service, Attention: FOI Reading Room, 1111 Constitution Avenue, N.W., Washington, D.C. 20224. The American Gas Association makes its Exempt Organization Return available for public inspection during normal business hours (9:00 a.m. - 5:00 p.m.) at the Association's principal office, 400 N. Capitol St., N.W., Washington, D.C. 20001, preferably by written request directed to Joseph L. Martin, AGA's Controller, at the same address. State public utility commissions that wish to receive a copy of AGA's Exempt Organization Return should also direct their request to Joseph Martin. Internal Revenue Service Form 4506-A may also be used to request copies of the return from the Internal Revenue Service if public inspection is not desired by the requestor. IRS may make a charge for its photocopying service.

(1) *Continued*

Revenue Recognition

Membership dues are recognized as revenue in the year to which the membership applies. Dues received in advance are deferred. Publications revenue is recognized upon the sale of the related publication and meetings revenue is recognized when the related meetings are held.

Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Functional Allocation of Expenses

The costs of providing the various programs and other activities have been summarized on a functional basis in the statements of activities. Accordingly, certain costs have been allocated among the programs and supporting services benefited. Salaries are charged directly to the programs and supporting services served. Fringe benefits are allocated to the programs and supporting services proportionate to salaries charged, and certain expenses benefiting all programs and supporting services are allocated based on the number of staff supporting each service.

Income Taxes

The Association is recognized as exempt from federal income tax under Section 501(c)(6) of the Internal Revenue Code, except for taxes on unrelated business income. Income tax expense on unrelated business activities totaled approximately $25,000 and $20,500 for the years ended December 31, 2002 and 2001, respectively.

The Association has elected to pay the federal proxy tax on behalf of its members on expenses related to lobbying activities. The proxy tax approximates $125,000 for both years ended December 31, 2002 and 2001.

Reclassifications

Certain reclassifications of prior year balances have been made to conform to the current year presentation.

(Continued)

AMERICAN GAS ASSOCIATION

Notes to Financial Statements

(2) Cash and Cash Equivalents and Marketable Securities

At December 31, 2002 and 2001, the components of cash and cash equivalents and marketable securities were as follows:

	2002	2001
Cash	$ 482,603	$ 461,013
Cash equivalents:		
Money market accounts	1,432,064	2,204,914
U.S. government agency obligations	599,760	-
Commercial paper	749,102	347,584
Total cash and cash equivalents	$ 3,263,529	$ 3,013,511
U.S. government agency obligations	$ 4,053,550	$ 4,322,497
Mortgage-backed securities	-	255,117
Corporate obligations	1,737,602	1,544,019
Other debt securities	9,128,124	9,968,957
Equity mutual funds and securities	5,757,285	6,980,682
Total marketable securities	$ 20,676,561	$ 23,071,272

(3) Property, Plant, and Equipment

Property, plant, and equipment are composed of the following as of December 31, 2002 and 2001:

	2002	2001
Leasehold improvements	$ 986,148	$ 949,311
Equipment	3,267,192	3,624,270
Furniture and fixtures	1,199,761	1,199,761
	5,453,101	5,773,342
Less accumulated depreciation and amortization	(2,844,837)	(2,557,526)
Property, plant, and equipment, net	$ 2,608,264	$ 3,215,816

(Continued)

AMERICAN GAS ASSOCIATION

Notes to Financial Statements

(4) Pension and Other Postretirement Benefits

The Association has the following noncontributory defined benefit pension plans:

- a qualified plan which covers substantially all Association employees,
- a non-qualified plan which is for employees who were determined to be eligible by the Association's Compensation Committee when the plan was created in 1985 (plan was frozen to new participants in 1986), and
- a non-qualified "excess" plan for those employees whose compensation exceeds the IRS limits for the qualified plan. This plan was approved by the Compensation Committee and is effective January 1, 2003.

These plans provide retirement benefits based on employees' years of services and compensation prior to retirement. In addition, there is an unfunded, nonqualified supplemental retirement benefit plan for the President and CEO that was approved by the Board of Directors in February 2001.

The funded plan's assets consist primarily of common stocks and U.S. government and corporate bonds.

The following provides a reconciliation of benefit obligations, plan assets, and funded status of the plans at December 31, 2002 and 2001:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Benefit obligation	$ 25,592,012	$ 23,168,922	$ 8,489,792	$ 7,554,951
Fair value of plan assets	19,832,983	23,282,900	4,203,939	5,037,630
Funded status	$ (5,759,029)	$ 113,978	$ (4,285,853)	$ (2,517,321)
Accrued benefit cost recognized in the statements of financial position	$ 1,531,068	$ 1,045,369	$ 850,289	$ 854,771
Intangible asset recognized in the statements of financial position	$ 98,428	$ -	$ -	$ -

(Continued)

AMERICAN GAS ASSOCIATION

Notes to Financial Statements

(4) Continued

Weighted-average assumptions:	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.50%	4.50%	N/A	N/A

Net periodic pension and other postretirement costs for 2002 and 2001 include the following components:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Pension (benefit) cost	$ 461,488	$ 139,626	$ 205,763	$ 23,285
Employer contribution	443,191	211,414	218,476	-
Plan participants' contributions	-	-	47,554	123,910
Benefits paid	1,576,467	1,341,069	545,110	594,492

In accordance with Statement of Financial Accounting Standard (SFAS) No. 87, *"Employers' Accounting for Pensions"*, the Association has recognized the required minimum liability represented by the excess of the accumulated benefit obligation over the plan assets at December 31, 2002 and 2001, which totaled $827,925 and $360,522, respectively. An intangible pension asset of $98,428, representing the unamortized prior service cost of the defined benefit plan, has been recognized within prepaid expenses and other assets in the accompanying statement of financial position as of December 31, 2002. The change in the total minimum liability of $368,975 is being recognized as a reduction to unrestricted net assets.

AMERICAN GAS ASSOCIATION
2021 and 2022 BUDGET

Expenses	$ 2021 Allocation	% 2021 Allocation	$ 2022 Allocation	% 2022 Allocation
Communications	$ 3,409,000	8.63%	$ 3,234,000	7.95%
Energy Markets, Analysis, and Standards	$ 4,840,000	12.26%	$ 4,403,000	10.82%
General and Administrative	$ 8,466,000	21.44%	$ 9,963,000	24.49%
General Counsel and Regulatory Affairs	$ 3,180,000	8.05%	$ 3,637,000	8.94%
Government Affairs and Public Policy	$ 5,428,000	13.74%	$ 5,991,000	14.73%
Industry Finance & Administrative Programs	$ 1,430,000	3.62%	$ 1,540,000	3.79%
Membership and Strategic Development	$ 4,222,000	10.69%	$ 4,323,000	10.63%
Operations and Engineering	$ 8,516,000	21.56%	$ 7,586,000	18.65%
Expense Budget *	$ 39,491,000	100.00%	$ 40,677,000	100.00%

Notes
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 3.8% of members dues in 2021.

* Does not include certain expenses or activities not funded by annual member company dues.

AGA
American Gas Association

VISION STATEMENT

Committed to leveraging and utilizing America's abundant, domestic, affordable and clean natural gas to help meet the nation's energy and environmental needs.

MISSION STATEMENT

The American Gas Association (AGA) represents companies delivering natural gas safely, reliably, and in an environmentally responsible way to help improve the quality of life for their customers every day. AGA's mission is to provide clear value to its membership and serve as the indispensable, leading voice and facilitator on its behalf in promoting the safe, reliable, and efficient delivery of natural gas to homes and businesses across the nation.

CORE STRENGTHS

1. Conducts programs and develops standards to help enhance the safe delivery of natural gas to consumers;
2. Advocates for natural gas industry issues, regulatory constructs and business models that are priorities for the industry;
3. Promotes growth in the efficient use of natural gas by emphasizing before a variety of stakeholders the benefits of clean, abundant natural gas as part of the solution to the nation's energy and environmental goals;
4. Facilitates the exchange of information and improvement of performance metrics to help members achieve operational excellence;
5. Helps members manage and respond to the energy needs of customers, regulatory trends, natural gas or capital market issues and emerging technologies;
6. Collects, analyzes and disseminates information to opinion leaders, policy makers and consumers about the benefits provided by energy utilities and the natural gas industry;
7. Encourages the development, commercialization, and regulatory acceptance of natural gas end-use technologies; and
8. Delivers measurable value to AGA members.

Approved: October 13, 2015

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 2017

Communications develops informational material for member companies and consumers and coordinates all media activity.

Corporate Affairs provides opportunities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

Energy Analysis & Standards identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics, and the environment. It supports the development of building energy codes and standards that help enhance natural gas safety.

General and Administrative includes:

1. Office of the President provides senior management guidance for all AGA activities.
2. Human Resources develops and administers employee programs and provides office and personnel services.
3. Finance and Administration develops and administers financial accounting and treasury services and maintains computer services capability.

General Counsel & Federal Regulatory Affairs includes:

1. General Counsel provides legal counsel to the Association.
2. Federal Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

Government Relations provides members with information on legislative developments; prepares testimony, comments, and filings regarding legislative activities, lobbies on behalf of the industry.

Industry Finance and Administration develops and implements programs in such areas as accounting, human resources, and risk management for member companies.

Operations and Engineering develops and implements programs and practices to meet the operational, safety, and engineering needs of the industry.

Policy leads AGA's policy strategy development, engages key stakeholders and policy makers and develops studies and joint initiatives that support advancing the industry's advocacy priorities. It supports the growth objectives of members by advancing sustainable growth opportunities for the direct and distributed use of natural gas in the residential, commercial and industrial markets.

SDR-RR-34

Request:

Please provide a copy of the most recent FERC audit findings, the Company's response and final disposition of audit exceptions.

Response:

A copy of our most recent FERC Audit findings can be found at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210114-3022&optimized=false.

Please see Attachment SDR-RR-34 for the Company's response to those findings.

No final disposition of the audit exceptions has occurred to date.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc.
1 UGI Drive
Denver, PA 17517
(610) 796-3400

Via Electronic Delivery

February 12, 2021

Kristen Fleet
Acting Director and Chief Accountant
Division of Audits and Accounting
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street NE, Room 51-59
Washington, DC 20426

RE: UGI Utilities, Inc.
Docket No. FA20-3-000
Implementation Plan in Response to January 14, 2021 Audit Report

Dear Ms. Fleet:

In conjunction with UGI Utilities, Inc.'s ("UGIU's") January 8, 2021 response to the Federal Regulatory Commission (the "Commission") audit report dated January 14, 2021 ("Audit Report"), please accept UGIU's plan of implementing the audit recommendations contained in the Audit Report.

As set forth in the attached implementation plan, UGIU accepts many of the Division of Audit and Accounting's ("DAA's") audit findings and recommendations in the Audit Report and provides documented corrective action plans and timelines for each of the 50 recommendations. UGIU will make quarterly submissions to DAA describing the progress made with respect to each recommendation, beginning within 30 days after the end of the first calendar quarter, and continuing until all the corrective actions are completed. UGIU's submission of its implementation plan is without prejudice to, or waiver of its rights, including its right to contest the Commission's authority generally to make retroactive changes to, or require refunds for, rates that have been allowed to go into effect.

Should you have any questions concerning UGIU's response, please direct your questions to [redacted], or me, at [redacted].

Sincerely,

[redacted]

Controller

INTRODUCTION

UGI Utilities, Inc. ("UGIU" or "the Company") hereby submits the following Implementation Plan ("Plan") in response to the Division of Audits and Accounting ("DAA") within the Office of Enforcement ("OE") of the Federal Energy Regulatory Commission's ("FERC") audit covering the period January 1, 2017 through July 29, 2020.

The Plan is organized to address each finding and recommendation contained in the OE'S audit report dated January 14, 2021. For each finding, the Plan states the Company's response, and for each recommendation, the Plan states the action to be taken, the individual responsible, and the expected completion date.

TABLE OF CONTENTS

UGI UTILITIES, INC.
IMPLEMENTATION PLAN FOR
FEDERAL ENERGY REGULATOR COMMISSION AUDIT
OFFICE OF ENFORCEMENT DOCKET NO. FA20-3-000

1. EXCESS ACCUMULATED DEFERRED INCOME TAX

UGIU improperly recorded the excess Accumulated Deferred Income Taxes (ADIT) related to the 2017 Tax Cuts and Jobs Act in Account 282, Accumulated Deferred Income Taxes – Other Property and Account 190, Accumulated Deferred Income Taxes. In addition, UGIU improperly excluded excess and deficient ADIT, created as a result of the 2017 Tax Cuts and Jobs Act, from its wholesale transmission formula rate computation. As a result, UGIU overstated its annual transmission revenue requirement by approximately $357,476 and overbilled wholesale transmission customers in 2018.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 1

Implement procedures to ensure that deficient and excess ADIT asset and liability amounts are included in rate base for the computation of the annual transmission revenue requirement.

Action: On May 15, 2020, UGIU submitted an Order No. 864 Compliance Filing making updates to its formula rate to encompass the impacts of the TCJA relates to such items as excess ADIT and its subsequent amortization. Further, in filing its 2019 FERC formula rate, the Company included the excess ADIT in its wholesale transmission formula rate computation. Lastly, the Company made correcting entries to reclass the deferred tax asset associated with the excess ADIT from account 190 to account 282.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Completed

RECOMMENDATION NO. 2

Revise its accounting policies and procedures to ensure that the effect of changes in tax laws or tax rates are implemented in accordance with the Commission’s accounting guidance in Docket No. AI93-5.

Action: UGIU will internally develop and deliver training to its staff to ensure that the effect of changes in tax laws or tax rates are implemented in accordance with the Commission’s accounting guidance. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 3

Submit correcting journal entries, within 60 days of issuance of this audit report, with proposed accounting entries and supporting documentation to DAA that reflect corrections to recorded excess and deficient ADIT in the appropriate USofA accounts.

Action: UGIU will submit correcting journal entries reflecting corrections to recorded excess and deficient ADIT in the appropriate USofA accounts to DAA.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 4

Submit a refund analysis, within 60 days of issuance of the audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of excess and deficient ADIT asset and liability amounts excluded from the transmission formula rates in 2018, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 4.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 5

File a refund report with the Commission after receiving DAA’s assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA’s assessment of the submitted refund analysis.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 6

Refund amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.

Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 6.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

2. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

UGIU's method for computing its AFUDC rate was deficient. Specifically, UGIU improperly excluded short-term debt, as the first source of financing construction, in calculating its AFUDC rate. In addition, UGIU improperly included Account 216.1, Unappropriated Undistributed Subsidiary Earnings, and Account 219, Accumulated Other Comprehensive Income, in the equity component to compute its AFUDC rate. Also, UGIU improperly used its fiscal year-end book balance for long-term debt and common equity amounts when computing its AFUDC rate rather than the calendar year-end balances reported in its FERC Form No. 1 during the audit period. As a result, UGIU overaccrued AFUDC amounts included in utility plant accounts by approximately $436,000 from 2017 to 2019 and overbilled wholesale transmission customers.

<u>UGIU Response</u>

UGIU accepts this finding and the recommendations. The Company has calculated the overaccrued amount related to transmission customers to be approximately $58,000.

RECOMMENDATION NO. 7

Revise and implement procedures to ensure that AFUDC rate calculations are consistent with Order Nos. 561 and 561-A, EPI No. 3 (A)(17), and other applicable Commission requirements.

Action: During 2019, UGIU revised its procedures to ensure that the AFUDC rate calculations are consistent with applicable Commission requirements.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: Completed

RECOMMENDATION NO. 8

Revise its procedures to ensure that it includes short-term debt in the computation of the AFUDC rate for its electric utility business.

Action: During 2019, UGIU revised its procedures to ensure that short-term debt is included in the computation of the AFUDC rate for its electric utility business.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: Completed

RECOMMENDATION NO. 9

Revise its procedures to exclude Account 216.1 and Account 219 balances from the equity components used to derive its AFUDC rate.

Action: During 2019, UGIU revised its procedures to exclude Account 216.1 and Account 219 balances from the equity components used to derive its AFUDC rate.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: Completed

RECOMMENDATION NO. 10

Revise its procedures to ensure that it computes AFUDC rates using the calendar year-end balances reported in its FERC Form No. 1 for common equity, preferred stock, and long-term debt.

Action: UGIU will file a request for waiver to continue its practice of using its fiscal year-end balances for common equity, preferred stock and long-term debt balances in its AFUDC rate computation.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: December 31, 2021

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RECOMMENDATION NO. 11

Provide training to its staff on the revised procedures implemented under Recommendation Nos. 7, 8, 9, and 10. Provide periodic training in these areas as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised procedures implemented under Recommendation Nos. 7, 8, 9, and 10. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 12

Recalculate its accrued AFUDC, in a manner consistent with EPI No. 3(A)(17) that corrects for the improper exclusion of short-term debt, improper inclusion of Account 216.1 and 219 balances, and improper use of fiscal year-end book balances for common equity, preferred stock, and long-term debt from 2012 through the date of issuance of the audit report.

Action: UGIU will recalculate its accrued AFUDC, as specified in recommendation no. 12.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 13

Submit proposed accounting entries and supporting documentation to DAA that reflect the correction of the CWIP, electric plant in service, accumulated depreciation, ADIT, and other accounts impacted by over-accrual of AFUDC within 60 days of issuance of the audit report.

Action: UGIU will submit proposed accounting entries and supporting documentation as specified in recommendation no. 13 to DAA.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: March 15, 2021

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RECOMMENDATION NO. 14

Submit a refund analysis, within 60 days of issuance of the audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of excess AFUDC included in the transmission formula rates since 2017, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains all items listed in recommendation no. 14.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 15

Revise CWIP, electric plant in service, accumulated depreciation, ADIT, and other accounts impacted by over-accrual of AFUDC after receiving DAA's assessment of the proposed accounting entries per Recommendation No. 13 and restate and footnote the FERC Form No. 1 for current and comparative years as necessary.

Action: UGIU will revise CWIP, electric plant in service, accumulated depreciation, ADIT, and other accounts impacted by over-accrual of AFUDC and restate and footnote the FERC Form No. 1 for current and comparative years as necessary.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: FERC Form No. 1 will be updated as necessary as described in recommendation No. 15 in the Company's first FERC Form No. 1 dated after the receipt of the DAA's assessment of the submitted proposed accounting entries.

RECOMMENDATION NO. 16

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 17

Refund the amounts disclosed in the refund report to wholesale customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 17.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

3. POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

UGIU improperly included ADIT related to SFAS 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, as an input to its wholesale transmission formula rate contrary to the directives of its tariff. As a result, UGIU overstated the ADIT balances included in its wholesale transmission formula rate, which led to overstating its annual transmission revenue requirements and overbilling its wholesale transmission customers.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 18

Revise and implement procedures, policies, and controls to track and review the transmission formula rate inputs and calculations for accuracy, completeness, and compliance with UGIU's Commission approved formula rate.

Action: UGIU corrected this inadvertent formula error in filing its 2020 FERC formula rate.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Completed

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RECOMMENDATION NO. 19

Provide training to staff on the revised wholesale transmission formula rate procedures. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised wholesale transmission formula rate procedures. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 20

Submit a refund analysis to DAA, within 60 days of issuance of this audit report, that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the inclusion SFAS 106 amounts plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 20.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 21

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.
Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 22

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.

Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 22.

Individual Responsible: Senior Manager Natural Gas Tax Accounting

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

4. COMMON PLANT O&M EXPENSES

UGIU improperly included common plant O&M expenses, that were also included as A&G expenses, in its wholesale transmission formula rate. As a result, UGIU double counted expenses associated with common plant, and consequently, overstated its wholesale transmission revenue requirement by approximately $423,454 during the audit period. This led UGIU to overbill its wholesale transmission customers.

<u>UGIU Response</u>

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 23

Develop and implement procedures, policies, and controls to ensure expenses included in the transmission formula rate are not included in multiple areas.

Action: UGIU will develop and implement procedures, policies, and controls, focusing on coding of the Company's natural chart of accounts, mapping to the FERC chart of accounts, and how those amounts are inputted to the Company's formula rate. This will ensure expenses included in the transmission formula rate are not included in multiple areas.

Individual Responsible: Assistant Controller

Expected Completion Date: May 15, 2021

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RECOMMENDATION NO. 24

Provide training to staff on the revised transmission formula rate procedures. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised transmission formula rate procedures. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 25

Submit a refund analysis, within 60 days of issuance of this audit report, to DAA for review that explains and details the following: (1) calculation of refunds to UGIU's wholesale transmission customers since 2017, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) for which refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 25.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 26

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Assistant Controller

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

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RECOMMENDATION NO. 27

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.
Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 27.

Individual Responsible: Assistant Controller

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

5. TRANSMISSION REVENUE CREDITS

UGIU understated its revenue credits that were used to reduce the annual transmission revenue requirements calculated by its wholesale transmission formula rate by improperly excluding certain transmission- related revenues recorded in Account 454, Rent from Electric Property. Additionally, UGIU improperly accounted for rental revenue associated with third parties' usage of its utility assets by recording such revenue in Account 418, Nonoperating Rental Income. As a result, UGIU understated the revenue credits includible in its wholesale transmission formula rate, which led to an overstatement of its annual transmission revenue requirements.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 28

Develop and implement procedures and policies to track, report, review, and account for wholesale transmission revenues consistent with Commission accounting and ratemaking requirements.

Action: UGIU will develop and implement procedures and policies to track, report, review, and account for wholesale transmission revenues consistent with Commission accounting and ratemaking requirements. This will include proper identification of wholesale transmission revenues at recognition and adjustments to the coding, as necessary, as well as review checks to ensure that all revenues are recorded to the proper FERC accounts.

Individual Responsible: Assistant Controller

Expected Completion Date: May 15, 2021

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RECOMMENDATION NO. 29

Provide training to staff on the revised accounting and wholesale transmission revenue procedures. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised accounting and wholesale transmission formula rate procedures. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 30

Perform an analysis of rental income accounts to identify revenues that were not properly credited to wholesale transmission customers through UGIU's transmission formula rates for the audit period. Provide the results of the analysis to audit staff within 60 days of the date of issuance of the audit report.

Action: UGIU will perform and submit the results of the analysis of rental income as specified in recommendation no. 30 to audit staff.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 31

Submit a refund analysis to DAA, within 60 days of receiving the audit report, that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the exclusion of revenue credits plus interest; (2) determinative components of the refund; (3) refund method; (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 31.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 32

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Assistant Controller

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 33

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.
Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 33.

Individual Responsible: Assistant Controller

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

6. ACCOUNTING FOR AFFILIATE TRANSACTIONS

UGIU misclassified various expenses associated with services provided by its parent company in Account 923, Outside Services Employed. Also, UGIU did not consistently apply its internally calculated, cost allocation percentages used to allocate costs between UGIU's electric utility business and its gas utility business. These allocation errors resulted in improper amounts being included in UGIU's wholesale transmission formula rate.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 34

Revise and implement procedures and policies to track, report, review, and account for UGI Corporation allocated expenses consistent with Commission accounting requirements.

Action: UGIU will revise and implement procedures and policies to track, report, review, and account for UGI Corporation allocated expenses consistent with Commission accounting requirements. This will include getting detail of all allocated expenses and properly assigning those to respective FERC accounts.

Individual Responsible: Assistant Controller

Expected Completion Date: May 15, 2021

RECOMMENDATION NO. 35

Revise and implement procedures, policies and controls to ensure the correct allocation factors are used to calculate and allocate common expenses recorded in the A&G accounts for the electric utility business.

Action: UGIU has revised its procedures, policies and controls to ensure the correct allocation factors are used to calculate and allocate common expenses recorded in the A&G accounts for the electric utility business. With the Company's implementation of a new ERP system, SAP, in July of 2019, employees are instructed to code common A&G costs to shared cost centers, which are then systematically allocated to the electric utility business based on the Company's annual MWF allocation. No manual allocation should be completed going forward. This methodology is also documented in UGIU's updated 2020 Cost Allocation Manual. Accounting also performs periodic checks to ensure that all costs coded to the shared cost centers are properly allocated.

Individual Responsible: Assistant Controller

Expected Completion Date: Completed

RECOMMENDATION NO. 36

Train staff on the procedures and policies and provide periodic training, as needed.

Action: UGIU will internally develop and deliver training to its staff specifying how UGI Corporation allocated expenses and UGIU common expenses should be coded to ensure that they are properly allocated and consistent with the Commission accounting requirements. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 37

Perform an analysis of A&G expense accounts to identify common expenses that were allocated using the incorrect allocation percentages during the audit period. Provide the results of the analysis to audit staff within 60 days of the date of issuance of the audit report.

Action: In conjunction with its response to recommendation no. 43, UGIU will perform an analysis of A&G expense accounts to identify expenses that were incorrectly allocated or improperly recorded. UGIU's analysis will consist of a reasonable sample of A&G expenses during the audit period. UGIU will submit the results of the analysis of A&G expense accounts to audit staff.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 38

Submit a refund analysis to DAA, within 60 days of receiving the audit report, that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the improper allocation of common expenses recorded in A&G accounts as identified pursuant to the analysis performed in response to Recommendation No. 43, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 38.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 39

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis.

Individual Responsible: Assistant Controller

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 40

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.
Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 40.

Individual Responsible: Assistant Controller

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

7. ACCOUNTING FOR ADMINISTRATIVE AND GENERAL EXPENSES

UGIU improperly recorded various A&G expenses in a manner contrary to the Commission's accounting regulations. As a result, UGIU overbilled wholesale transmission customers.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 41

Revise policies and procedures to ensure that UGIU properly accounts for expenditures in its books and records.

Action: UGIU will revise its policies and procedures to ensure that expenditures are properly accounted for. This will include proper coding of invoices, as well as policies to periodically review the Company's mapping from its natural chart of accounts to the FERC chart of accounts.

Individual Responsible: Assistant Controller

Expected Completion Date: May 15, 2021

RECOMMENDATION NO. 42

Provide training to its staff on the revised procedures for properly accounting for expenditures in UGIU's books and records. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised procedures for properly accounting for expenditures in UGIU's books and records. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

RECOMMENDATION NO. 43

Perform an analysis of A&G expense accounts to identify expenses that were inappropriately recovered through UGIU's transmission formula rate and the related customer billings, such as advertising, donations, lobbying, distribution O&M costs, legal costs, and asset insurance improperly charged to accounts included in the transmission formula rate during the audit period. Provide the results of the analysis to audit staff within 60 days of the date of issuance of the audit report.

Action: In conjunction with its response to recommendation no. 37, UGIU will perform an analysis of A&G expense accounts to identify expenses that were incorrectly allocated or improperly recorded. UGIU's analysis will consist of a reasonable sample of A&G expenses during the audit period. UGIU will submit the results of the analysis of A&G expense accounts to audit staff.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

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RECOMMENDATION NO. 44

Submit a refund analysis to DAA, within 60 days of receiving the audit report, that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the improper accounting for expenses recorded in A&G accounts as identified pursuant to the analysis performed in response to Recommendation No. 43, plus interest; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

Action: UGIU will complete and submit a refund analysis to DAA that explains and details all items listed in recommendation no. 44.

Individual Responsible: Assistant Controller

Expected Completion Date: March 15, 2021

RECOMMENDATION NO. 45

File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Action: UGIU will file a consolidated refund report with the Commission after receiving DAA's assessment of the submitted refund analysis

Individual Responsible: Assistant Controller

Expected Completion Date: Within 60 days of receiving DAA's assessment of the submitted refund analysis.

RECOMMENDATION NO. 46

Refund the amounts disclosed in the refund report to wholesale transmission customers with interest calculated in accordance with section 35.19a of the Commission's regulations.

Action: UGIU will refund amounts disclosed in the refund report as specified in recommendation no. 46.

Individual Responsible: Assistant Controller

Expected Completion Date: Amounts will be refunded as a reduction of UGIU's transmission rates, reflected in its first formula rate filing following the filing of the related refund report.

8. FILING OF DEPRECIATION RATES WITH THE COMMISSION

UGIU did not file its depreciation rate schedule with the Commission when depreciation rates were changed. This hindered the Commission's and other interested parties' ability to timely review and monitor UGIU's depreciation rates, which impact prices charged for wholesale transmission services through the formula rate.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 47

Develop and implement processes and procedures to ensure that depreciation rates and related studies are filed with the Commission when depreciation rates are changed.

Action: UGIU will develop and implement a process to ensure that depreciation rates and related studies are filed with the Commission when depreciation rates are changed.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: May 15, 2021

RECOMMENDATION NO. 48

File current depreciation studies with the Commission relating to UGIU's current annual transmission revenue requirement within 60 days of issuance of this audit report.

Action: UGIU will file current depreciation studies with the Commission relating to UGIU's current annual transmission revenue requirement.

Individual Responsible: Senior Manager, SOX, Plant Accounting & AP

Expected Completion Date: March 15, 2021

9. FERC FORM NO. 1 REPORTING

UGIU did not properly follow the FERC Form No. 1 instructions and, therefore, did not report all required information in its FERC Form No. 1 filings.

UGIU Response

UGIU accepts this finding and the recommendations.

RECOMMENDATION NO. 49

Revise and strengthen documented policies, procedures, and practices to ensure information reported in the FERC Form No. 1 is correct, accurate, and consistent with the instructions of the form.

Action: UGIU will revise and strengthen policies, procedures, and practices to ensure information reported in the FERC Form No. 1 is correct, accurate and consistent with the instructions.

Individual Responsible: Assistant Controller

Expected Completion Date: Time of filing UGIU's December 31, 2020 FERC Form No. 1.

RECOMMENDATION NO. 50

Provide training to staff on the revised FERC Form No. 1 policies, procedures, and practices. Also, develop a training program that supports the provision of periodic training in this area, as needed.

Action: UGIU will internally develop and deliver training to its staff on the revised FERC Form No. 1 policies, procedures, and practices. In addition, UGIU will formalize future periodic training with internal and external counsel to ensure that the proper accounting individuals are knowledgeable on any FERC accounting and tax updates.

Individual Responsible: Assistant Controller

Expected Completion Date: The internal training will be conducted by May 15, 2021. The training with counsel will be conducted within 12 months of issuance of the audit report.

SDR-RR-35

Request:

Please provide the annual level of forfeited discounts or late payment charges for the preceding three calendar years. Identify the level of sales revenue with which these are associated.

Response:

Please see Attachment SDR-RR-35.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division

Forfeited Discounts and Late Payment Charges Schedule

For the twelve months ending September 30 ($ in 000's):

	2019	2020	2021
Forfeited Discounts and Late Payment Charges	$ 5,635	$ 2,815	$ 4,882
Sales Revenue[1]	$ 828,380	$ 835,001	$ 843,571

[1] Includes billed revenue only

SDR-RR-36

Request:

If not reflected in the lead-lag study, please provide a listing of the various types of employee withholdings, garnishments and other employee funds held by the Company for remittance at a later date.

Response:

United Way
Operation Share
Union Dues
Potter Game Club
Voluntary Accidental Death & Dismemberment
Employee Supplemental Life
Spouse Life
Child Life
Medical, Dental, and Vision
Flexible Spending Account
Political Action Committee
UGI Stock Purchase Plan
Employee Bill Payments
Other Various Wage Attachments (Federal, State Taxes)

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-37

Request:

Please provide all detailed work papers supporting the adjustments to rate base and operating income.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Fully Projected), Sections C and D.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-38

Request:

Please provide a copy of the Company's most recent SFAS 106 plan actuarial study.

Response:

UGI Gas' most recent SFAS 106 plan actuarial studies were conducted at the end of Fiscal Year 2021. Please refer to Attachment SDR-RR-38 for a copy of the reports issued as a result of these studies.

Prepared by or under the supervision of: Vivian K. Ressler

WillisTowersWatson

September 30, 2021

[redacted]
UGI Utilities, Inc.
1 UGI Drive
Denver, PA 17517

[redacted]

ACCOUNTING VALUATION RESULTS FOR UGI UTILITIES POSTRETIREMENT WELFARE PLAN

This letter provides the fiscal 2021 valuation results under ASC 715-60 for the UGI Utilities, Inc. Postretirement Welfare Plan. The valuation results are based on participant census data collected as of January 1, 2021 and VEBA trust assets as of September 30, 2020 provided by UGI.

These valuation results are used to measure the postretirement welfare accounting expense (income) for the 2021 fiscal year (October 1, 2020 to September 30, 2021).

POSTRETIREMENT WELFARE PLAN EXPENSE (INCOME)

Below is a summary of expense (income) for fiscal 2021 by company compared to fiscal 2020.

Company	2021 Fiscal Year	2020 Fiscal Year
Holding Company	$ 22,690	$ 20,299
Utilities	(232,758)	(419,066)
Enterprises	264	319
TOTAL ACCOUNTING EXPENSE (INCOME)	**$ (209,804)**	**$ (398,448)**

The results for fiscal 2021 yield an increase in postretirement welfare expense (decrease in income) of approximately $190,000. The primary reason for this change is the expiration of approximately $225,000 in prior service credit amortizations in fiscal 2021.

The fiscal 2021 income slightly increased from the budget estimate of $(196,000) prepared for UGI in November 2020 primarily due to modest actuarial gains in service cost from demographic experience.

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Details of the 2021 postretirement welfare expense results by reporting segment are provided below.

Valuation Results by Company as of October 1, 2020 (Fiscal 2021 Expense)

	Holding Company	Utilities	Enterprises	Total
Accumulated Postretirement Benefit Obligation (APBO):				
▪ Medical	$ 0	$ 179,015	$ 0	$ 179,015
▪ Life Insurance	1,108,978	9,685,875	38,153	10,833,006
▪ Total	$ 1,108,978	$ 9,864,890	$ 38,153	$ 11,012,021
Postretirement Welfare Expense				
▪ Service Cost	$ 11,094	$ 127,645	$ 0	$ 138,739
▪ Interest Cost	33,091	293,762	1,127	327,980
▪ EROA	(21,495)	(635,891)	0	(657,386)
▪ Amortization of Transition Obligation	0	0	0	0
▪ Amortization of Prior Service Cost	0	(18,274)	(863)	(19,137)
▪ Amortization of (Gains)/Losses	0	0	0	0
Net Accounting Cost	$ 22,690	$(232,758)	$ 264	$(209,804)

DEMOGRAPHICS

The total number of retirees, surviving spouses, and dependents with medical coverage dropped from 76 to 62 during 2020.

The following is the breakdown of retiree medical participants (all are post-65):

Retirees and Surviving Spouses	Dependents	Total
43	19	62

The following is the breakdown of life insurance participants:

Active	490
Retiree	547
Total	1,037

INVESTMENT EXPERIENCE

The plan's actual return on assets for the period October 1, 2019 to September 30, 2020 was approximately 11.1%.

ASSUMPTIONS

- Discount rate: 3.00%
- Weighted-average salary increase assumption from age 40 to average retirement age of 3.25%
- Mortality: Pri-2012 blue collar table with rates decreased by 4.9%, projected Scale MP-2019 on a generational basis
- The expected return on VEBA trust assets: 7.10% pre-tax and 5.00% post-tax for fiscal 2021. The medical plan sub-account is subject to UBIT taxation and uses the lower rate. This assumption reflects a portfolio diversified in equities and bonds.

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[redacted]
September 30, 2021

- The health care trend assumption: an initial rate of 6.25% in fiscal 2021 decreasing to a 5.00% in fiscal 2026.

The following assumption changes were reflected in the determination of the postretirement welfare expense for fiscal 2021:

- The valuation discount rate was changed from 3.30% as of October 1, 2019 to 3.00% as of October 1, 2020.
- The assumption for mortality was changed from RP-2014 blue collar table with rates decreased by 5.5%, projected using Scale MP-2018 on a generational basis from 2006 to Pri-2012 blue collar table with rates decreased by 4.9%, projected Scale MP-2019 on a generational basis
- Assumptions for termination and retirement were updated to better reflect plan experience.

Other assumptions remain unchanged from fiscal 2020 and are documented in the October 1, 2019 valuation report.

A comprehensive list of actuarial assumptions including the rationale for key assumptions will be summarized in the 2021 actuarial valuation report which will be available in a few weeks.

PLAN PROVISIONS

There have been no changes in plan provisions since the most recent valuation. A summary of key plan provisions can be found in the October 1, 2019 valuation report.

EXPECTED CLAIMS AND EXPENSES

Total expected claims and expenses (net of retiree contributions) from October 1, 2020 to September 30, 2021 for the retiree welfare plans are as follows:

Expected Company Claims and Expenses for 2021	
UGI Postretirement Medical	$ 30,000
UGI Postretirement Life Insurance	409,000
Total	$439,000

Most of the claims and expenses would be paid (or reimbursed) from the VEBA trust for current and former “non-key” employees. Benefits for any current and former key employees would be paid from company assets.

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In preparing these results Willis Towers Watson has used the information and data provided to us by UGI. We have relied on all the data and information provided, including plan provisions as being complete and accurate. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information.

The results contained in this letter are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. Certain plan provisions may be approximated or determined to be immaterial and therefore not valued. Assumptions may be made about participant data or other factors. We have made reasonable efforts to ensure that items that are material in the context of the actuarial liabilities or costs are treated appropriately, and not excluded or included inappropriately.

Actual future experience will differ from the assumptions used in our calculations. As these differences arise, contributions or the cost for accounting purposes will be adjusted in future valuations to take changes into account. If these adjustments become material, they may result in future adjustments to the valuation model.

As required by ASC 715, the actuarial assumptions and methods employed in the development of the pension cost have been selected by the plan sponsor. ASC 715-30-35 requires that each significant assumption "individually represent the best estimate of a particular future event." Willis Towers Watson has concurred with these assumptions and methods.

Accumulated other comprehensive (income)/loss amounts shown in the report are shown prior to adjustment for deferred taxes. Any deferred tax effects in AOCI should be determined in consultation with UGI's tax advisors and auditors. Willis Towers Watson used information supplied by UGI regarding postretirement benefit asset, postretirement benefit liability and amounts recognized in accumulated other comprehensive income as of September 30, 2020. This data was reviewed for reasonableness and consistency, but no audit was performed.

The results contained in this letter have been developed based on actuarial assumptions that, to the extent evaluated or selected by Willis Towers Watson, we consider to be reasonable. Other actuarial assumptions could also be considered to be reasonable. Thus, reasonable results differing from those presented in this report could have been developed by selecting different reasonable assumptions.

The results provided in this letter have been prepared solely for the benefit of UGI to assist with its year-end financial reporting. This email should not be used for other purposes and we accept no responsibility for any such use. It should not be relied upon by, or shared with, any third parties without Willis Towers Watson's prior written consent.

This letter provides actuarial information. It does not constitute legal, accounting, tax or investment advice. We encourage UGI to consult with qualified advisors with respect to those matters.

ASOP 56 DISCLOSURE

Quantify is the Willis Towers Watson centrally developed, tested and maintained Global actuarial valuation system. It is used to perform valuations of clients' benefit plans. Quantify provides the ability to process data, calculate benefits and value benefit liabilities, develop results using applicable standards, and generate client reports. Quantify parameters provide significant flexibility to model populations and plan designs. Various demographic, economic and benefit related assumptions exist for users to model multiple demographic and economic situations.

Plan liabilities are calculated based on standard actuarial techniques, developing actuarially reasonable results using the population and parameters entered The calculation and presentation of liabilities in Quantify relies on the assumptions used and the reasonability of the assumptions selected. Quantify incorporates standard liability methodologies that are intended to reasonably reflect a variety of economic or demographic conditions. The model itself does not evaluate any assumptions entered for reasonableness, consistency or probability of occurrence.

Quantify is designed specifically for these purposes, and we know of no material limitations that would prevent the system from being suitable for these intended purposes. The actuaries signing this report have relied on the actuaries who develop, test and maintain this system, and have also performed a limited review of results to ensure that system parameters have been set appropriately and plan provisions coded correctly.

WillisTowersWatson

[redacted]
September 30, 2021

RATE:Link is a methodology to develop spot rates to be used for measurements related to employee benefit plans. The same core methodology is used to develop all RATE:Link curves. The RATE:Link process develops term structures of interest rates from corporate bond data for each covered market. The construction of RATE:Link yield curves relies on bond data collected as of the measurement date. Information regarding quoted bond prices, yields and other bond related data is from Bloomberg Finance L.P

U.S. BOND:Link is a methodology to assist with the selection of discount rates used in measurements related to employee benefit plans. Discount rates are derived by identifying a theoretical settlement portfolio of high- quality corporate bonds sufficient to provide for a plan’s projected benefit payments. The single interest rate is then determined that results in a discounted value of the plan’s benefit payments that equals the market value of the selected bond portfolio.

Updated BOND:Link models are developed monthly as of the last day of the month. The construction of a BOND:Link model relies on bond data collected as of the measurement date Parameters provide the user the ability to control aspects of the model. The model output allows the user to see the effect of those parameters. Information regarding quoted bond prices, yields and other bond related data is from Bloomberg Finance L.P.

****

The undersigned consulting actuaries are members of the Society of Actuaries and meet the “Qualification Standard for Actuaries Issuing Statements of Actuarial Opinion in the United States” relating to pension and other postretirement benefit plans. Our objectivity is not impaired by any relationship between UGI and our employer, Willis Towers Watson.

Please reach out to us if you have any questions.

Sincerely,

Christopher S. Zukas, FSA
Director, Retirement

Direct Dial: (215) 246-6104

Lori Wolfersberger, FSA
Associate Director, Retirement

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ACCOUNTING VALUATION RESULTS FOR CENTRAL PENN GAS POSTRETIREMENT WELFARE PLAN

This letter contains the Central Penn Gas Postretirement Welfare Plan valuation results for fiscal year 2021 under ASC 715-60. The accounting cost for postretirement welfare benefits decreased from $10,000 in fiscal year 2020 to $(17,618) in fiscal year 2021. The primary reason for the decrease in expense was due to favorable asset experience during fiscal 2020.

The $(17,618) also compares to an estimated cost/(income) of $(17,000) provided in November 2020.

A reconciliation of the cost decrease from fiscal 2020 to fiscal 2021 is as follows:

Fiscal 2020 net periodic benefit cost/(income)	$ 10,000
Expected decrease based on prior valuation	(7,104)
Asset experience	(22,535)
Plan experience losses (gains)	(1,111)
Change in termination and retirement assumptions	(3,734)
Change in mortality	640
Change in discount rate	6,226
Fiscal 2021 net periodic benefit cost	$ (17,618)

The table on the next page below summarizes the participant counts and financial results for the current and prior accounting valuations for Central Penn Gas. Census data as of January 1, 2021 and January 1, 2020 were used for the fiscal 2021 and fiscal 2020 valuations respectively.

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September 30, 2021

Central Penn Gas
Postretirement Welfare Plan Actuarial Valuation

	October 1, 2020	October 1, 2019
Number of Participants:		
■ Medical Benefits		
Active	0	0
Retiree / Surviving Spouse	54	56
Dependent	38	41
Total	92	97
■ Life Insurance		
Active	104	112
Retiree	60	53
Total	164	165
Accumulated Postretirement Benefit Obligation (APBO):		
■ Medical	$ 446,021	$ 491,446
■ Life Insurance	1,199,352	1,077,111
■ Total	$ 1,645,373	$ 1,568,557
Fair Value of Plan Assets (FVA):	$ 2,183,122	$ 2,073,138
Postretirement Welfare Expense		
■ Service Cost	$25,549	$24,351
■ Interest Cost	50,769	51,401
■ Expected Return on Assets	(107,504)	(101,899)
■ Amortization of Transition Obligation	0	0
■ Amortization of Prior Service Cost	(93,033)	(93,033)
■ Amortization of (Gains)/Losses	106,601	129,180
Net Accounting Cost	**$(17,618)**	**$10,000**

ASSUMPTIONS

The fiscal 2021 postretirement welfare expense determined above uses the following assumptions:

- Discount rate: 3.10%
- 3.25% weighted-average salary increase assumption from age 40 to average retirement age
- Health care inflation of 6.25% for fiscal 2021 decreasing to 5.00% in fiscal 2026
- Mortality: Pri-2012 blue collar table with rates decreased by 4.9%, projected Scale MP-2019 on a generational basis
- The expected return on VEBA trust assets: 7.10% pre-tax and 5.00% post-tax for fiscal 2021. The medical plan sub-account is subject to UBIT taxation and uses the lower rate. This assumption reflects a portfolio diversified in equities and bonds.

The following assumption changes were reflected in the determination of the postretirement welfare expense for fiscal 2021:

- The valuation discount rate was changed from 3.30% as of October 1, 2019 to 3.10% as of October 1, 2020.

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- The assumption for mortality was changed from RP-2014 blue collar table with rates decreased by 5.5%, projected using Scale MP-2018 on a generational basis from 2006 to Pri-2012 blue collar table with rates decreased by 4.9%, projected Scale MP-2019 on a generational basis
- Assumptions for termination and retirement were updated to better reflect plan experience.

Other assumptions remain unchanged from fiscal 2020 and are documented in the October 1, 2019 valuation report.

A comprehensive list of actuarial assumptions including the rationale for key assumptions will be summarized in the 2021 actuarial valuation report which will be available in a few weeks.

PLAN PROVISIONS

There have been no changes in plan provisions since the most recent valuation. A summary of key plan provisions can be found in the October 1, 2019 valuation report.

* * * * *

In preparing these results Willis Towers Watson has used the information and data provided to us by UGI. We have relied on all the data and information provided, including plan provisions as being complete and accurate. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information.

The results contained in this letter are estimates based on data that may be imperfect and on assumptions about future events that cannot be predicted with any certainty. Certain plan provisions may be approximated or determined to be immaterial and therefore not valued. Assumptions may be made about participant data or other factors. We have made reasonable efforts to ensure that items that are material in the context of the actuarial liabilities or costs are treated appropriately, and not excluded or included inappropriately.

Actual future experience will differ from the assumptions used in our calculations. As these differences arise, contributions or the cost for accounting purposes will be adjusted in future valuations to take changes into account. If these adjustments become material, they may result in future adjustments to the valuation model.

As required by ASC 715, the actuarial assumptions and methods employed in the development of the pension cost have been selected by the plan sponsor. ASC 715-30-35 requires that each significant assumption “individually represent the best estimate of a particular future event.” Willis Towers Watson has concurred with these assumptions and methods.

Accumulated other comprehensive (income)/loss amounts shown in the report are shown prior to adjustment for deferred taxes. Any deferred tax effects in AOCI should be determined in consultation with UGI’s tax advisors and auditors. Willis Towers Watson used information supplied by UGI regarding postretirement benefit asset, postretirement benefit liability and amounts recognized in accumulated other comprehensive income as of September 30, 2020. This data was reviewed for reasonableness and consistency, but no audit was performed.

The results contained in this letter have been developed based on actuarial assumptions that, to the extent evaluated or selected by Willis Towers Watson, we consider to be reasonable. Other actuarial assumptions could also be considered to be reasonable. Thus, reasonable results differing from those presented in this report could have been developed by selecting different reasonable assumptions.

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[redacted]
September 30, 2021

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Please reach out to us if you have any questions.

Sincerely,

Christopher S. Zukas, FSA
Director, Retirement

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Lori Wolfersberger, FSA
Associate Director, Retirement

(215) 246-4942

CSZ:dlm

cc: [redacted]

WillisTowersWatson

September 30, 2021

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[redacted]

ACCOUNTING VALUATION RESULTS FOR PENN NATURAL GAS POSTRETIREMENT WELFARE PLAN

This letter contains the Penn Natural Gas Postretirement Welfare Plan valuation results for fiscal year 2021 under ASC 715-60. The accounting cost for postretirement welfare benefits increased from $(26,767) in fiscal year 2020 to $(21,054) for fiscal year 2021. The primary reason for the increase in expense (decrease in income) from fiscal 2020 to fiscal 2021 is the decrease in the discount rate of 20 basis points and demographic experience (fewer than expected terminations and deaths).

The actual cost/(income) of $(21,054) compares to an estimated cost/(income) of $(30,000) provided in November 2020.

A reconciliation of the cost decrease from fiscal 2020 to fiscal 2021 is as follows:

Fiscal 2020 net periodic benefit cost/(income)	$ (26,767)
Expected decrease based on prior valuation	(1,174)
Asset experience	(13,390)
Plan experience losses (gains)	8,859
Change in termination and retirement assumptions	1,937
Change in mortality	2,229
Change in discount rate	7,252
Fiscal 2021 net periodic benefit cost/(income)	$ (21,054)

The table on the next page summarizes the participant counts and financial results for the current and prior accounting valuations for The Penn Natural Gas Postretirement Welfare Plan.

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[redacted]
September 30, 2021

Penn Natural Gas
Postretirement Welfare Plan Actuarial Valuation

	October 1, 2020	October 1, 2019
Number of Participants:		
■ Active	114	117
■ Inactive	48	45
■ Total	162	162
Accumulated Postretirement Benefit Obligation:	$ 1,217,597	$ 1,051,607
Fair Value of Assets	1,506,680	1,375,117
Funded Status	$ 289,083	$ 323,510

	Fiscal Year 2021	Fiscal Year 2020
Postretirement Welfare Expense		
■ Service Cost	$ 14,077	$ 12,547
■ Interest Cost	40,461	37,069
■ Expected Return on Assets	(75,055)	(68,505)
■ Amortization of Prior Service Cost	1,167	2,508
■ Amortization of (Gains)/Losses	(1,704)	(10,386)
Net Accounting Cost	**$ (21,054)**	**$ (26,767)**

ASSUMPTIONS

The fiscal 2021 Postretirement Welfare expense determined above uses the following assumptions:

- Discount rate: 3.30%
- Weighted-average salary increase assumption from age 40 to average retirement age of 3.25%
- Mortality: Pri-2012 blue collar table with rates decreased by 4.9%, projected Scale MP-2019 on a generational basis
- The expected return on VEBA trust assets: 7.10% pre-tax and 5.00% post-tax for fiscal 2021. The medical plan sub-account is subject to UBIT taxation and uses the lower rate. This assumption reflects a portfolio diversified in equities and bonds.

The following assumption changes were reflected in the determination of the postretirement welfare expense for fiscal 2021:

- The valuation discount rate was changed from 3.50% as of October 1, 2019 to 3.30% as of October 1, 2020.
- The assumption for mortality was changed from RP-2014 blue collar table with rates decreased by 5.5%, projected using Scale MP-2018 on a generational basis from 2006 to Pri-2012 blue collar table with rates decreased by 4.9%, projected Scale MP-2019 on a generational basis
- Assumptions for termination and retirement were updated based on the results of an experience study conducted in 2020.

Other assumptions remain unchanged from fiscal 2020 and are documented in the October 1, 2019 valuation report.

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A comprehensive list of actuarial assumptions including the rationale for key assumptions will be summarized in the 2021 actuarial valuation report which will be available in a few weeks.

PLAN CHANGES

There have been no changes in plan provisions since the most recent valuation. A summary of key plan provisions can be found in the October 1, 2019 valuation report.

* * * * *

In preparing these results Willis Towers Watson has used the information and data provided to us by UGI. We have relied on all the data and information provided, including plan provisions as being complete and accurate. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information.

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Willis Towers Watson

[redacted]
September 30, 2021

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Willis Towers Watson

Please reach out to us if you have any questions.

Sincerely,

Christopher S. Zukas

Christopher S. Zukas, FSA
Director, Retirement

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Associate Director, Retirement

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cc: [redacted]

SDR-RR-39

Request:

Please reconcile the historical and future test year SFAS No. 106 expense levels with the amount identified in the actuarial report.

Response:

Please see Attachment SDR-RR-39 for the schedule reconciling SFAS No. 106 expenses for all three test years.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Schedule of SFAS No. 106 Expenses

		HTY 9/30/2021	FTY 9/30/2022	FPFTY 9/30/2023
Amortization of Regulatory Liability		$ (974,464)	$ (974,464)	$ (974,464)
Actual/Budget Year Expense/(Income)		(246,160)	(314,694)	(332,832)
Total Actual/Budget Year Expense/(Income)		$ (1,220,624)	$ (1,289,158)	$ (1,307,296)
Actuarial Expense (Income)		$ (246,160)	$ (382,712)	N/A
Difference		$ (974,464)	$ (906,447)	
Reconciling Items:				
Amortization of Regulatory Liability	(1)	$ (974,464)	$ (974,464)	
Actual/Budget Year Expense/(Income)	(2)	-	68,017	
		$ 974,464	$ 906,447	

(1) HTY and FTY expense/(income) includes $974,464 per year of amortization expense for a regulatory liability associated with the over recovery of SFAS 106 costs, which is not part of the actuarial expense (income).

(2) The $68,017 reconciling item for the FTY is the result of the annual budget being prepared (based on an estimate) before the actuarial report totals for the year were available. There is no reconciling difference in the HTY because we record a true-up entry at year end to make our expense/(income) equal to the actuarial report.

SDR-RR-40

Request:

Please identify the actual or projected amounts contributed to SFAS No. 106 funds for the historic and future test years. Identify the actual or projected dates and amounts of the contributions.

Response:

There are no actual or projected SFAS 106 contributions included in the historic, future or fully projected future test years.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-41

Request:

Please explain the funding options or plans which are being used for SFAS No. 106 costs. Identify the portion of the costs which are eligible for tax preferred funding.

Response:

All of the SFAS No. 106 (post-employment plan) costs are funded assets which are held in a tax advantaged VEBA trust.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-42

Request:

Is the Company studying and/or anticipating any changes to its postretirement benefits offered to employees as a result of SFAS No. 106 or for other reasons? If yes, please provide such study and/or explain the anticipated change.

Response:

The Company is not studying or anticipating any changes to its postretirement benefits offered to employees.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-43

Request:

Please state whether the Company has included expenses related to SFAS No. 112 in its test year claim. If so, please provide complete details and include a copy of the actuarial study.

Response:

Yes. However, in accordance with HIPAA guidelines, UGI Gas does not record or track these additional expenses separately from active employee benefit costs. For this reason, UGI Gas does not have the ability to calculate this additional post-employment benefit expense.

The Company's most recent SFAS 112 actuarial study was conducted at the end of Fiscal Year 2021. Refer to Attachment SDR-RR-43 for a copy of the report issued as a result of this study.

Prepared by or under the supervision of: Vivian K. Ressler

WillisTowersWatson

October 4, 2021

[redacted]
Director, Corporate Reporting
UGI Corporation
Irwin Building
460 N. Gulph Road
King of Prussia, PA 19406

[redacted]

UGI FAS 112 VALUATION RESULTS AS OF SEPTEMBER 30, 2021

The purpose of this letter is to provide you with the estimated FAS 112 obligations for UGI Utilities and Penn Natural Gas (PNG) group as of September 30, 2021. Consistent with the September 30, 2020 results, the UGI Utilities results contain the obligations attributable to Central Penn Gas (CPG) participants as well.

Valuation Results

Below is a summary of the estimated FAS 112 obligations as of September 30, 2021 for UGI's short-term disability (STD) income benefit and COBRA continuation of health coverage (long-term disability income, medical and life insurance continuation are estimated by UGI and are not included with the results presented in this letter). In addition, the FAS 112 obligation for PNG is provided for the STD income benefit. Each of the obligations was developed according to the standards of FAS 112, 5 and 43. For comparative purposes the individual plan obligations are shown relative to September 30, 2020 results.

	Obligation as of					
	September 30, 2021			**September 30, 2020**		
Benefit	**Current**	**Non-Current**	**Total**	**Current**	**Non-Current**	**Total**
STD income (UGI+CPG+PNG)	$882,000	$1,477,000	$2,358,000	$820,000	$1,368,000	$2,188,000
COBRA	258,000	0	258,000	236,000	0	236,000
Total	1,140,000	1,477,000	2,616,000	1,056,000	1,368,000	2,424,000

Philadelphia Consulting Office
1735 Market Street
Philadelphia, PA 19103-7501

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W willistowerswatson.com

Willis Towers Watson

[redacted]
October 4, 2021

Please note the following regarding this year's valuation results:

Short-term Disability Income Continuation

The UGI+CPG+PNG obligation for the STD income benefit as of September 30, 2021 is $2,358,000 using a 3.0% discount rate; this compares to $2,188,000 as of September 30, 2020 using a 3.0% discount rate.

The liability amount represents the obligation for the STD income benefit to which employees are entitled as years of active service increase. The valuation reflects the costs associated with all future disabilities expected to occur after September 30, 2021. The rates of incidence and duration of STD claims are based on a blend of standard actuarial assumptions and actual experience received from UGI, CPG and PNG.

COBRA Continuation of Health Coverage

This amount represents UGI's obligation for the additional medical expense anticipated from COBRA participants above the 102% of premium UGI collects from COBRA beneficiaries. The projected cost of health coverage is based on UGI's average 2021 cost of providing these benefits for COBRA participants.

George, if you have any questions or need further information, please call us.

Sincerely,

Marc B. Freedman, ASA
Direct Dial: 215-246-6280

Daniel Callahan, FSA
Direct Dial: 215-246-7336

MBF/edd

cc: [redacted]

Willis Towers Watson

[redacted]
October 4, 2021

September 30, 2021 FAS 112 Methods and Assumptions – UGI+CPG+PNG

<u>Short-term Disability Income Continuation</u>

<u>UGI+CPG+PNG</u>

Methods and Assumptions

Discount Rate	3.0%	
Incidence of disability	5.3%	
Average duration of disability	7.0 weeks	
Accounting method	FAS 43, LIFO	
Benefit schedule	Weeks at 100%	Weeks at 50%
Service (years)		
Less than 1	1	0
1 less than 2	3	0
2 less than 5	5	8
5 less than 10	8	18
10 less than 15	12	14
15 less than 20	17	9
20+	26	0
Average age	45.4	
Average years of service	12.3	
Percent male	69%	
Average salary	$82,176	
Headcount	2,265	

Willis Towers Watson

[redacted]
October 4, 2021

COBRA

UGI+CPG

Methods and Assumptions

Discount Rate	3.0%
Accounting method	FAS 5
Average age	54.7
Percent male	55%
Expected utilization	150% of average
Headcount	44
Average monthly rate	$1,273

V:\UGI CORPORATION - 110001\16\HGB\2021 FAS112\SEP 30 2021 FAS 43 DISABILITY INCOME\DELIVERABLE\UGI FAS 112 VALUATION RESULTS AS OF 9302021 LETTER.DOCX/

Willis Towers Watson

Information Related to Actuarial Standard of Practice No. 56

AGEDIST

AgeDist is a spreadsheet tool that applies relative cost factors by age to average per capita costs (pre and post 65) and census weights to produce age-graded plan costs for pre- and post-65 populations. The average per capita costs and census weights are provided as inputs to the tool which is then combined with a morbidity curve to produce a set of weighted average age-related costs that equal the average. The age-graded costs are used in the actuarial valuation.

The morbidity curve was developed from a broad set of claims data aggregated by age and blended and may not reflect your specific morbidity. The model does not evaluate the average per capita costs or census weights for reasonableness or consistency.

The model(s) used for this analysis is designed specifically for these purposes, and we know of no material limitations that would prevent the model(s) from being suitable for these intended purposes.

We are not aware of any material inconsistencies among assumptions used in this work. The model itself does not evaluate any assumptions entered for reasonableness, consistency or probability of occurrence. The calculation and presentation of results relies on the assumptions used and the reasonability of the assumptions selected. The output of the model(s) used in this analysis are considered reasonable based on the aggregation of assumptions used. However, a different set of results could also be considered reasonable based on a range of possible values used for each assumption.

The individuals signing or delivering this report have relied on other Willis Towers Watson employees and actuaries who develop, test and maintain each of the proprietary models used for this analysis and have also performed a basic review of assumptions and results to ensure that the models have been set up appropriately and coded correctly. We have not relied on any external experts to develop, review, or validate the model(s) used in this analysis

In preparing the results presented in this report, we have relied upon information provided to us regarding plan provisions, plan participants, participant contribution amounts and/or claims data. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this report is dependent upon the accuracy and completeness of the underlying information. We are aware of no errors or omissions that would have a significant effect on the results of our calculations.

Quantify

Quantify is the Willis Towers Watson centrally developed, tested and maintained Global actuarial valuation system. It is used to perform valuations of clients' benefit plans. Quantify provides the ability to process data, calculate benefits and value benefit liabilities, develop results using applicable standards, and generate client reports. Quantify parameters provide significant flexibility to model populations and plan designs. Various demographic, economic and benefit related assumptions exist for users to model multiple demographic and economic situations.

Plan liabilities are calculated based on standard actuarial techniques, developing actuarially reasonable results using the population and parameters entered the calculation and presentation of liabilities in Quantify relies on the assumptions used and the reasonability of the assumptions selected. Quantify incorporates standard liability methodologies that are intended to reasonably reflect a variety of economic or demographic conditions. The model itself does not evaluate any assumptions entered for reasonableness, consistency or probability of occurrence.

Quantify is designed specifically for these purposes, and we know of no material limitations that would prevent the system from being suitable for these intended purposes. The actuaries signing this report have relied on the actuaries who develop, test and maintain this system, and have also performed a limited review of results to ensure that system parameters have been set appropriately and plan provisions coded correctly.

RATE:Link

RATE:Link is a methodology to develop spot rates to be used for measurements related to employee benefit plans. The same core methodology is used to develop all RATE:Link curves. The RATE:Link process develops term structures of interest rates from corporate bond data for each covered market. The construction of RATE:Link yield curves relies on bond data collected as of the measurement date. Information regarding quoted bond prices, yields and other bond related data is from Bloomberg Finance L.P

Willis Towers Watson

[redacted]
October 4, 2021

Actuarial Certification

UGI retained Willis Towers Watson to perform a valuation of its postemployment benefit plans in order to determine its postemployment benefit cost in accordance with ASC 712 (formerly FAS 112). This valuation has been conducted in accordance with generally accepted actuarial principles and practices.

The consulting actuaries are members of the Society of Actuaries and other professional actuarial organizations and meet the “Qualification Standards for Actuaries Issuing Statements of Actuarial Opinion in the United States” relating to postemployment benefit plans.

In preparing the results presented in this report, we have relied upon information provided to us regarding plan provisions, plan participants, and plan costs. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this report is dependent upon the accuracy and completeness of the underlying information.

The actuarial assumptions and the accounting policies and methods employed in the development of the postemployment benefit cost have been selected by the plan sponsor, with the concurrence of Willis Towers Watson. ASC 712 requires that each significant assumption “individually represent the best estimate of a particular future event.”

The results shown in this report are reasonable actuarial results. However, a different set of results could also be considered reasonable actuarial results, since the actuarial standards of practice describe a “best-estimate” range for each assumption, rather than a single best-estimate value. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

The information contained in this report was prepared for the internal use of UGI and its auditors in connection with our actuarial valuation of the postemployment benefit plans. It is neither intended nor necessarily suitable for other purposes. UGI may also distribute this actuarial valuation report to the appropriate authorities who have the legal right to require UGI to provide them with this report, in which case UGI will use best efforts to notify Willis Towers Watson of this distribution. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited without Willis Towers Watson’s prior written consent.

Marc Freedman

Marc B. Freedman, ASA
Willis Towers Watson

Daniel Callahan, FSA
Willis Towers Watson

SDR-RR-44

Request:

Please provide all documentation supporting the uncollectible accrual rate reflected in the Company's filing.

Response:

Please refer to UGI Gas Exhibit A (Historic), UGI Gas Exhibit (A (Future), and UGI Gas Exhibit A (Fully Projected Future), Schedule D-11, for a calculation of the uncollectible accrual rate.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-45

Request:

Please provide all work papers and documentation supporting the Company's claimed balance of gas stored underground - current. Include support for the monthly injections and withdrawals and the gas cost rate.

Response:

Please see Attachment SDR-RR-45.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
GAS STORED UNDERGROUND - CURRENT
SEPTEMBER 2020 - SEPTEMBER 2021

Month	Injections DTH	Withdrawals DTH	Inventory Change DTH	Inventory Balance DTH	Injected Value	Withdrawn Value	Monthly $ Change	Balance $ Value	Average Weighted Cost of Inventory $ per DTH
Beginning Balance				11,071,346				$ 16,336,272	
September 2020	2,148,185	(196,510)	1,951,675	13,023,021	$ 3,855,012	$ (318,664)	$ 3,536,348	$ 19,872,620	$ 1.5260
October 2020	2,444,620	(234,901)	2,209,719	15,232,740	$ 4,053,726	$ (384,595)	$ 3,669,131	$ 23,541,751	$ 1.5455
November 2020	319,042	(548,332)	(229,290)	15,003,450	$ 514,013	$ (853,670)	$ (339,657)	$ 23,202,094	$ 1.5465
December 2020	39,233	(2,761,238)	(2,722,005)	12,281,445	$ 92,574	$ (4,343,155)	$ (4,250,581)	$ 18,951,513	$ 1.5431
January 2021	72,845	(4,110,005)	(4,037,160)	8,244,285	$ 52,341	$ (6,407,242)	$ (6,354,901)	$ 12,596,612	$ 1.5279
February 2021	39,021	(4,175,733)	(4,136,712)	4,107,573	$ 130,508	$ (6,489,003)	$ (6,358,495)	$ 6,238,117	$ 1.5187
March 2021	193,385	(2,677,776)	(2,484,391)	1,623,182	$ 451,386	$ (4,129,029)	$ (3,677,643)	$ 2,560,473	$ 1.5774
April 2021	1,914,410	(646,501)	1,267,909	2,891,091	$ 4,089,494	$ (1,155,780)	$ 2,933,714	$ 5,494,187	$ 1.9004
May 2021	2,132,111	(373,767)	1,758,344	4,649,435	$ 4,893,384	$ (804,166)	$ 4,089,218	$ 9,583,405	$ 2.0612
June 2021	2,551,956	79,058	2,631,014	7,280,449	$ 6,138,294	$ 166,138	$ 6,304,432	$ 15,887,837	$ 2.1823
July 2021	2,413,847	(138,136)	2,275,711	9,556,160	$ 7,470,370	$ (347,255)	$ 7,123,115	$ 23,010,952	$ 2.4080
August 2021	2,342,421	(146,160)	2,196,261	11,752,421	$ 8,492,242	$ (398,825)	$ 8,093,418	$ 31,104,370	$ 2.6466
September 2021	2,203,105	(223,224)	1,979,881	13,732,302	$ 9,075,013	$ (660,078)	$ 8,414,935	$ 39,519,305	$ 2.8778

Sub Total:	$ 231,563,235
Number of Months:	13
Average Monthly Balance:	$ 17,812,557

SDR-RR-46

Request:

Please provide a comparison between actual and budgeted O&M expenses by budget cost element for the historical test year and explain any budget variances of 10 percent or more.

Response:

Please see Attachment SDR-RR-46.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division

Actual versus Budgeted Cost Element Comparison

Comparison - Actual to Budget FY 2021 ($000)

	Actual 2021	Budget 2021	Variance	% Variance
Cost of Sales	404,896	411,779	6,883	1.7%
Maintenance and Other Operating Expenses	210,693	218,336	7,643	3.5%
Depreciation/Amortization	109,154	106,921	(2,233)	(2.1%)
Taxes Other than Income Taxes	8,709	11,255	2,546	22.6%
Total Operating Expenses	733,452	748,291	14,839	2.0%

Maintenance and Other Operating Expenses

	Actual 2021	Budget 2021	Variance	% Variance
Payroll and Employee Benefits	90,398	95,249	4,851	5.1%
Transportation	3,719	5,335	1,616	30.3%
Contracted Labor, Materials and Equipment	32,761	33,002	241	0.7%
Uncollectible Allowance	11,932	11,850	(82)	(0.7%)
Information Technology	18,197	21,210	3,013	14.2%
Other	53,686	51,690	(1,996)	(3.9%)
	210,693	218,336	7,643	3.5%

Taxes Other than Income Taxes

The favorable variance in Taxes Other than Income Taxes was primarily driven by lower payroll taxes.

Transportation

The favorable variance in Transportation expense was primarily driven by lower fleet expenses.

Information Technology

The favorable variance in Information Technology expense was primarily driven by lower than anticipated hardware and software maintenance expenses.

SDR-RR-47

Request:

Please provide the most recent actual number of eligible participants in each of the employee medical and dental plans reflected in the Company's filing.

Response:

See Attachment SDR-RR-47.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Enrolled Employees for Calendar 2022 (as of November 2021)

Medical - Aetna POS II	Count as of 1/2022
Employee	252
Employee + spouse	91
Employee + child	45
Employee + children	46
Family	81
TOTAL	515

Medical - Independence BlueCross PPO	Count as of 1/2022
Employee	138
Employee + spouse	52
Employee + child	19
Employee + children	26
Family	54
TOTAL	289

Medical - Aetna HAP	Count as of 1/2022
Employee	145
Employee + spouse	46
Employee + child	39
Employee + children	25
Family	67
TOTAL	322

Medical - Independence BlueCross HDP	Count as of 1/2022
Employee	145
Employee + spouse	30
Employee + child	18
Employee + children	17
Family	71
TOTAL	281

Dental - United Concordia Basic	Count as of 1/2022
Employee	484
Employee + Spouse	154
Employee + child	59
Employee + children	50
Family	202
TOTAL	949

Dental - United Concordia Buy Up	Count as of 1/2022
Employee	241
Employee + Spouse	115
Employee + child	38
Employee + children	59
Family	122
TOTAL	575

SDR-RR-48

Request:

Please provide workpapers showing the derivation of future test year Social Security and Medicare FICA taxes based on future test year labor expense. Identify both the total and O&M amounts.

Response:

Please refer to UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedules D-31 and D-32.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-49

Request:

Please provide work papers showing the derivation of future test year federal and state unemployment taxes. Show both the total and O&M amounts.

Response:

Please refer to UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Fully Projected), Schedules D-31 and D-32.

Prepared by or under the supervision of: Tracy A. Hazenstab

SDR-RR-50

Request:

Please provide work papers showing the derivation of future test year capital stock taxes.

Response:

Not applicable. The PA Capital Stock tax was eliminated for tax years beginning January 1, 2016.

Prepared by or under the supervision of: Nicole M. McKinney

SDR-RR-51

Request:

If applicable, please provide a copy of the billing and payment terms for all contracts between the Company and its parent or an affiliated company for services. Further, to the extent that the parent or affiliated company provides service to non-affiliated companies, please provide the corresponding billing and payment terms.

Response:

Please see the response to III-A-22.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-52

Request:

Please provide the annual level of outside services employed for the preceding three calendar years. Include in your response a breakdown of the test year amount indicating the service provider and the type of service performed.

Response:

Please see the response to III-A-28.

Prepared by or under the supervision of: Vivian K. Ressler

SDR-RR-53

Request:

Please describe each budgeted or planned cost savings program to be implemented during the historic or future year. Please identify the cost of implementing the program and the anticipated annual savings.

Response:

While not related to a specific program, included in both the FTY and the FPFTY is an anticipated $2.4 million of procurement savings associated with the consolidation of the non-energy supply component of UGI Utilities' procurement function within UGI Corporation.

Prepared by or under the supervision of: Christopher R. Brown

SDR-RR-54

Request:

Please explain how the Company has treated reserve accruals and balances for ratemaking purposes and provide the requested level of any self-funded reserve accruals by type of item.

Response:

Please refer to Attachment SDR-RR-54.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Schedule of Reserve Accruals and Balances
(Thousands of Dollars)

Reserve Type	HTY Balance 9/30/21	Expense Treatment for Ratemaking Purposes	Related Adjustment Schedules (1)
Environmental	$53,531	Adjusted to a three-year historical average, plus or minus the amount of reconcilable cost differences since the last rate case (2)	Schedule D-8
Bad Debt	$14,518	Adjusted by applying the three-year historical average uncollectible percentage to adjusted revenues	Schedule D-11
Workers' Compensation	$1,513	No adjustment required (3)	None
Medical	$1,300	No adjustment required (3)	None
Injuries & Damages	$1,668	Adjusted to a three-year historical average	Schedule D-15

(1) Each respective schedule is disclosed in UGI Gas Exhibit A (Historic), Exhibit A (Future) and Exhibit A (Fully Projected).
(2) Refer to the Direct Testimony of Vivian K. Ressler, UGI Gas Statement No. 3 for discussion of the environmental adjustment.
(3) There are no related ratemaking adjustments required, as expenses are budgeted on a normalized basis.

SDR-RR-55

Request:

Please provide a copy of the corporate federal tax returns and supporting schedules for the preceding three years and, if applicable, a copy of the calculation work papers for the Company's consolidated tax savings adjustment.

Response:

UGI Gas is included as part of a consolidated federal income tax return. Since the complete federal tax return is a voluminous document, only excerpts from the preceding three years' returns are provided. Please see Attachment SDR-RR-55 for these excerpts. The complete tax returns are available at UGI Corporation headquarters in King of Prussia, PA.

Please also see the response to II-A-26 for the calculation of a consolidated tax savings adjustment.

Prepared by or under the supervision of: Nicole M. McKinney

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2017 or tax year beginning 10/01/2017, ending 09/30/2018

▶ Go to *www.irs.gov/Form1120* for instructions and the latest information.

OMB No. 1545-0123 | **2017**

A Check if:
1a Consolidated return (attach Form 851) X
b Life/nonlife consolidated return
2 Personal holding co. (attach Sch. PH)
3 Personal service corp. (see instructions)
4 Schedule M-3 attached X

TYPE OR PRINT

Name: UGI Corporation & Subsidiaries
Number, street, and room or suite no. If a P.O. box, see instructions.: P.O. BOX 858
City or town, state, or province, country, and ZIP or foreign postal code: Valley Forge, PA 19482

B Employer identification number: 23-2668356
C Date incorporated: 12/01/1994
D Total assets (see instructions): $ 6,981,830,376.

E Check if: (1) Initial return (2) Final return (3) Name change (4) Address change

Income	1a	Gross receipts or sales	1a	3,172,307,157.		
	b	Returns and allowances	1b			
	c	Balance. Subtract line 1b from line 1a			1c	3,172,307,157.
	2	Cost of goods sold (attach Form 1125-A)			2	2,169,989,931.
	3	Gross profit. Subtract line 2 from line 1c			3	1,002,317,226.
	4	Dividends (Schedule C, line 19)			4	NONE
	5	Interest			5	8,595,059.
	6	Gross rents			6	2,626,037.
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	1,888,165.
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	1,812,652.
	10	Other income (see instructions - attach statement) See Statement 3			10	37,502,433.
	11	**Total income.** Add lines 3 through 10 ▶			11	1,054,741,572.
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions - attach Form 1125-E) ▶			12	15,814,794.
	13	Salaries and wages (less employment credits)			13	148,813,333.
	14	Repairs and maintenance			14	105,047,330.
	15	Bad debts			15	12,703,966.
	16	Rents			16	3,738,825.
	17	Taxes and licenses			17	47,341,347.
	18	Interest			18	61,057,136.
	19	Charitable contributions See Statement 6			19	2,171,169.
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	486,155,032.
	21	Depletion			21	434,691.
	22	Advertising			22	2,305,105.
	23	Pension, profit-sharing, etc., plans			23	7,219,411.
	24	Employee benefit programs			24	16,272,772.
	25	Domestic production activities deduction (attach Form 8903)			25	
	26	Other deductions (attach statement) See Statement 7			26	124,934,746.
	27	**Total deductions.** Add lines 12 through 26 ▶			27	1,034,009,657.
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11			28	20,731,915.
	29a	Net operating loss deduction (see instructions)	29a			
	b	Special deductions (Schedule C, line 20)	29b	NONE		
	c	Add lines 29a and 29b			29c	NONE
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28. See instructions			30	20,731,915.
	31	Total tax (Schedule J, Part I, line 11)			31	7,214,792.
	32	Total payments and refundable credits (Schedule J, Part II, line 21)			32	48,589,168.
	33	Estimated tax penalty. See instructions. Check if Form 2220 is attached ▶			33	
	34	**Amount owed.** If line 32 is smaller than the total of lines 31 and 33, enter amount owed			34	
	35	**Overpayment.** If line 32 is larger than the total of lines 31 and 33, enter amount overpaid			35	41,374,376.
	36	Enter amount from line 35 you want: **Credited to 2018 estimated tax** ▶		41,374,376.	Refunded ▶ 36	

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer: MICHAEL R PEARSON | Date: 07/08/2019 | Title: VICE PRESIDENT CORP TAX ADMIN

May the IRS discuss this return with the preparer shown below? See instructions. Yes No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check if self-employed	PTIN

Firm's name ▶ | Firm's EIN ▶
Firm's address ▶ | Phone no.

UGI Corporation & Subsidiaries 23-2668356

Schedule C Dividends and Special Deductions (see instructions)

		(a) Dividends received	(b) %	(c) Special deductions (a) x (b)
1	Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	NONE	70	NONE
2	Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		80	
3	Dividends on debt-financed stock of domestic and foreign corporations		see instructions	
4	Dividends on certain preferred stock of less-than-20%-owned public utilities		42	
5	Dividends on certain preferred stock of 20%-or-more-owned public utilities		48	
6	Dividends from less-than-20%-owned foreign corporations and certain FSCs		70	
7	Dividends from 20%-or-more-owned foreign corporations and certain FSCs		80	
8	Dividends from wholly owned foreign subsidiaries		100	
9	**Total.** Add lines 1 through 8. See instructions for limitation			NONE
10	Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11	Dividends from affiliated group members		100	
12	Dividends from certain FSCs		100	
13	Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, or 12			
14	Income from controlled foreign corporations under subpart F (attach Form(s) 5471)			
15	Foreign dividend gross-up			
16	IC-DISC and former DISC dividends not included on line 1, 2, or 3			
17	Other dividends			
18	Deduction for dividends paid on certain preferred stock of public utilities			
19	**Total dividends.** Add lines 1 through 17. Enter here and on page 1, line 4 ▶	NONE		
20	**Total special deductions.** Add lines 9, 10, 11, 12, and 18. Enter here and on page 1, line 29b ▶			NONE

UGI Corporation & Subsidiaries 23-2668356

Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ▶ ☐				
2	Income tax. Check if a qualified personal service corporation. See instructions ▶ ☐			2	5,085,283.
3	Alternative minimum tax (attach Form 4626)			3	NONE
4	Add lines 2 and 3			4	5,085,283.
5a	Foreign tax credit (attach Form 1118)	5a	NONE		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c	751,196.		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	751,196.
7	Subtract line 6 from line 4			7	4,334,087.
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement) See Statement 17	9f	2,880,705.		
10	**Total.** Add lines 9a through 9f			10	2,880,705.
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	7,214,792.

Part II-Payments and Refundable Credits

12	2016 overpayment credited to 2017			12	18,582,636.
13	2017 estimated tax payments			13	30,000,000.
14	2017 refund applied for on Form 4466			14	( )
15	Combine lines 12, 13, and 14			15	48,582,636.
16	Tax deposited with Form 7004			16	
17	Withholding (see instructions)			17	
18	**Total payments.** Add lines 15, 16, and 17			18	48,582,636.
19	Refundable credits from:				
a	Form 2439	19a			
b	Form 4136	19b	6,532.		
c	Form 8827, line 8c	19c			
d	Other (attach statement - see instructions)	19d			
20	**Total credits.** Add lines 19a through 19d			20	6,532.
21	**Total payments and credits.** Add lines 18 and 20. Enter here and on page 1, line 32			21	48,589,168.

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a ☐ Cash b ☒ Accrual c ☐ Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ N/A		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X

UGI Corporation & Subsidiaries 23-2668356

Schedule K **Other Information** *(continued from page 3)*

	Yes	No
5 At the end of the tax year, did the corporation:		
a Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851**, Affiliations Schedule? For rules of constructive ownership, see instructions.	X	
If "Yes," complete (i) through (iv) below. See Statement 18		

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock

	Yes	No
b Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions.	X	
If "Yes," complete (i) through (iv) below. See Statement 20		

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital

	Yes	No
6 During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316		X
If "Yes," file **Form 5452**, Corporate Report of Nondividend Distributions. See the instructions for Form 5452.		
If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		
7 At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of the total voting power of all classes of the corporation's stock entitled to vote or at least 25% of the total value of all classes of the corporation's stock?		X
For rules of attribution, see section 318. If "Yes," enter:		
(a) Percentage owned ▶ ______ and **(b)** Owner's country ▶ ______		
(c) The corporation may have to file **Form 5472**, Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶ ______		
8 Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ ☐		
If checked, the corporation may have to file **Form 8281**, Information Return for Publicly Offered Original Issue Discount Instruments.		
9 Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $ ______		
10 Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶ ______		
11 If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here ▶ ☐		
If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election will not be valid.		
12 Enter the available NOL carryover from prior tax years (do not reduce it by any deduction reported on page 1, line 29a.) ▶ $ ______		
13 Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year **and** its total assets at the end of the tax year less than $250,000?		X
If "Yes," the corporation is not required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $ ______		
14 Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions	X	
If "Yes," complete and attach Schedule UTP.		
15a Did the corporation make any payments in 2017 that would require it to file Form(s) 1099?	X	
b If "Yes," did or will the corporation file required Forms 1099?	X	
16 During this tax year, did the corporation have an 80% or more change in ownership, including a change due to redemption of its own stock?		X
17 During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18 Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?	X	
19 During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?	X	

UGI Corporation & Subsidiaries 23-2668356

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	(b)	End of tax year (c)	(d)
1 Cash		342,797,357.		258,428,383.
2a Trade notes and accounts receivable	125,010,997.		177,965,878.	
b Less allowance for bad debts	(5,461,695.)	119,549,302.	(11,082,325.)	166,883,553.
3 Inventories		88,556,872.		98,639,879.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)	Stmt 27	102,245,815.		117,569,594.
7 Loans to shareholders				
8 Mortgage and real estate loans				
9 Other investments (attach statement)	Stmt 35	1,977,280,151.		2,139,770,478.
10a Buildings and other depreciable assets	4,368,498,743.		4,813,984,988.	
b Less accumulated depreciation	(1,194,120,059.)	3,174,378,684.	(1,299,453,283.)	3,514,531,705.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)		24,948,240.		24,935,559.
13a Intangible assets (amortizable only)	294,960,766.		223,200,277.	
b Less accumulated amortization	(15,692,108.)	279,268,658.	(17,260,508.)	205,939,769.
14 Other assets (attach statement)	Stmt 40	462,479,032.		455,131,456.
15 Total assets		6,571,504,111.		6,981,830,376.
Liabilities and Shareholders' Equity				
16 Accounts payable		163,707,069.		215,501,970.
17 Mortgages, notes, bonds payable in less than 1 year		249,771,941.		201,322,652.
18 Other current liabilities (attach statement)	Stmt 44	149,556,386.		150,819,259.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		1,400,899,831.		1,436,924,917.
21 Other liabilities (attach statement)	Stmt 53	1,444,287,358.		1,345,179,912.
22 Capital stock: a Preferred stock				
b Common stock				
23 Additional paid-in capital		1,186,671,406.		1,199,506,775.
24 Retained earnings - Appropriated (attach statement)				
25 Retained earnings - Unappropriated		2,108,622,574.		2,612,429,855.
26 Adjustments to shareholders' equity (attach statement)		-93,448,369.		-159,798,285.
27 Less cost of treasury stock		(38,564,085.)		(20,056,679.)
28 Total liabilities and shareholders' equity		6,571,504,111.		6,981,830,376.

Schedule M-1 Reconciliation of Income (Loss) per Books With Income per Return

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 Analysis of Unappropriated Retained Earnings per Books (Line 25, Schedule L)

1 Balance at beginning of year	2,108,622,574.	5 Distributions: a Cash	176,903,746.
2 Net income (loss) per books	615,382,700.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize) Stmt 63	38,027,073.
See Statement 59	103,355,400.	7 Add lines 5 and 6	214,930,819.
4 Add lines 1, 2, and 3	2,827,360,674.	8 Balance at end of year (line 4 less line 7)	2,612,429,855.

SCHEDULE M-3 (Form 1120)
Department of the Treasury
Internal Revenue Service

Net Income (Loss) Reconciliation for Corporations With Total Assets of $10 Million or More

▶ Attach to Form 1120 or 1120-C.
▶ Go to *www.irs.gov/Form1120* for instructions and the latest information.

OMB No. 1545-0123
2017

Name of corporation (common parent, if consolidated return): UGI Corporation
Employer identification number: 23-2668356

Check applicable box(es): (1) ☐ Non-consolidated return (2) ☐ Consolidated return (Form 1120 only)
(3) ☒ Mixed 1120/L/PC group (4) ☐ Dormant subsidiaries schedule attached

Part I Financial Information and Net Income (Loss) Reconciliation (see instructions)

1 a Did the corporation file SEC Form 10-K for its income statement period ending with or within this tax year?
☒ **Yes.** Skip lines 1b and 1c and complete lines 2a through 11 with respect to that SEC Form 10-K.
☐ **No.** Go to line 1b. See instructions if multiple non-tax-basis income statements are prepared.

b Did the corporation prepare a certified audited non-tax-basis income statement for that period?
☐ **Yes.** Skip line 1c and complete lines 2a through 11 with respect to that income statement.
☐ **No.** Go to line 1c.

c Did the corporation prepare a non-tax-basis income statement for that period?
☐ **Yes.** Complete lines 2a through 11 with respect to that income statement.
☐ **No.** Skip lines 2a through 3c and enter the corporation's net income (loss) per its books and records on line 4a.

2 a Enter the income statement period: Beginning 10/01/2017 Ending 09/30/2018

b Has the corporation's income statement been restated for the income statement period on line 2a?
☐ **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
☒ **No.**

c Has the corporation's income statement been restated for any of the five income statement periods immediately preceding the period on line 2a?
☐ **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
☒ **No.**

3 a Is any of the corporation's voting common stock publicly traded?
☒ **Yes.**
☐ **No.** If "No," go to line 4a.

b Enter the symbol of the corporation's primary U.S. publicly traded voting common stock . . . . . UGI

c Enter the nine-digit CUSIP number of the corporation's primary publicly traded voting common stock 902681105

4 a	Worldwide consolidated net income (loss) from income statement source identified in Part I, line 1	**4a**	718,711,691.
b	Indicate accounting standard used for line 4a (see instructions): (1) ☒ GAAP (2) ☐ IFRS (3) ☐ Statutory (4) ☐ Tax-basis (5) ☐ Other (specify)		
5 a	Net income from nonincludible foreign entities (attach statement) Stmt. 66.	**5a**	(103,355,400).
b	Net loss from nonincludible foreign entities (attach statement and enter as a positive amount)	**5b**	
6 a	Net income from nonincludible U.S. entities (attach statement)	**6a**	( )
b	Net loss from nonincludible U.S. entities (attach statement and enter as a positive amount)	**6b**	
7 a	Net income (loss) of other includible foreign disregarded entities (attach statement)	**7a**	
b	Net income (loss) of other includible U.S. disregarded entities (attach statement)	**7b**	
c	Net income (loss) of other includible entities (attach statement)	**7c**	
8	Adjustment to eliminations of transactions between includible entities and nonincludible entities (attach statement)	**8**	
9	Adjustment to reconcile income statement period to tax year (attach statement)	**9**	
10 a	Intercompany dividend adjustments to reconcile to line 11 (attach statement)	**10a**	
b	Other statutory accounting adjustments to reconcile to line 11 (attach statement)	**10b**	
c	Other adjustments to reconcile to amount on line 11 (attach statement) Stmt. 67.	**10c**	26,409.
11	**Net income (loss) per income statement of includible corporations.** Combine lines 4 through 10	**11**	615,382,700.

Note: Part I, line 11, must equal Part II, line 30, column (a) or Schedule M-1, line 1 (see instructions).

12 Enter the total amount (not just the corporation's share) of the assets and liabilities of all entities included or removed on the following lines.

		Total Assets	Total Liabilities
a	Included on Part I, line 4 ▶	11,938,028,450.	7,837,981,253.
b	Removed on Part I, line 5 ▶	1,658,446,299.	1,116,575,795.
c	Removed on Part I, line 6 ▶		
d	Included on Part I, line 7 ▶		

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [X] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): Nonlife Consolidation

Employer identification number:

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25				
27 **Total expense/deduction items** (from Part III, line 38)				
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28	615,446,048.	-493,597,286.	-100,877,567.	20,971,195.
b PC insurance subgroup reconciliation totals	-63,348.	-20,138.	-155,788.	-239,274.
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	615,382,700.	-493,617,424.	-101,033,355.	20,731,921.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) ☐ Consolidated group (2) ☐ Parent corp (3) ☐ Consolidated eliminations (4) ☐ Subsidiary corp (5) ☒ Mixed 1120/L/PC group

Check if a sub-consolidated: (6) ☒ 1120 group (7) ☐ 1120 eliminations

Name of subsidiary (if consolidated return): 1120 Subgroup

Employer identification number:

Part II **Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return** (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed	98,502,829.	-98,502,829.		
3 Subpart F, QEF, and similar income inclusions				
4 Section 78 gross-up				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation		-14,924,445.	14,924,445.	
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	87,256,939.	-22,566,448.		64,690,491.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	6,917,992.	-1,816,554.		5,101,438.
14 Total accrual to cash adjustment				
15 Hedging transactions	-20,053,395.	-19,811,547.	-129,823.	-39,994,765.
16 Mark-to-market income (loss)	28,898,830.			28,898,830.
17 Cost of goods sold (see instructions)	(1,783,087,953.)	-362,228,402.		(2,145,316,355.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	-182,184.	192,611.	-10,427.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		138,590.		138,590.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory			864,052.	864,052.
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	-414,259,835.	403,179,453.	-3,106,414.	-14,186,796.
26 **Total income (loss) items.** Combine lines 1 through 25	-1,996,006,777.	-116,339,571.	12,541,833.	-2,099,804,515.
27 **Total expense/deduction items** (from Part III, line 38)	-290,162,652.	-377,257,715.	-113,419,400.	-780,839,767.
28 Other items with no differences	2,901,615,477.			2,901,615,477.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	615,446,048.	-493,597,286.	-100,877,567.	20,971,195.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	615,446,048.	-493,597,286.	-100,877,567.	20,971,195.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): 1120 Subgroup

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-4,910,667.		4,910,667.	
2 U.S. deferred income tax expense	-76,196,532.		76,196,532.	
3 State and local current income tax expense	24,161,769.	-266,294.		23,895,475.
4 State and local deferred income tax expense	5,461,204.	-5,461,204.		
5 Foreign current income tax expense (other than foreign withholding taxes)	165,372.	-165,372.		
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Interest expense (see instructions)	54,767,744.	2,355,350.	1.	57,123,095.
9 Stock option expense	5,905,687.	-514,440.	35,173,147.	40,564,394.
10 Other equity-based compensation	10,828,976.	-6,751,933.	1,779,914.	5,856,957.
11 Meals and entertainment	1,398,812.		-829,737.	569,075.
12 Fines and penalties	1,014,483.		-1,014,214.	269.
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation	2,511,450.		-511,450.	2,000,000.
16 Pension and profit-sharing	17,019,701.	-9,800,290.		7,219,411.
17 Other post-retirement benefits	-970,513.	886,962.		-83,551.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	2,124,947.	-300.	-4,714.	2,119,933.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization/impairment of goodwill	1,026.	11,376,540.		11,377,566.
27 Amortization of acquisition, reorganization, and start-up costs	486,943.	-438,250.		48,693.
28 Other amortization or impairment write-offs	14,071,538.	-8,105,073.		5,966,465.
29 Reserved				
30 Depletion		434,691.		434,691.
31 Depreciation	120,818,647.	365,336,528.		486,155,175.
32 Bad debt expense	18,324,596.	-5,620,630.		12,703,966.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)	23,451.	123,422.		146,873.
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Other expense/deduction items with differences (attach statement)	93,154,018.	33,868,008.	-2,280,746.	124,741,280.
38 **Total expense/deduction items.** Combine lines 1 through 37. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	290,162,652.	377,257,715.	113,419,400.	780,839,767.

UGI Corporation & Subsidiaries 23-2668356

Consolidated Schedules
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		Combined	UGI Eliminations Top Consolidation	Adjustments	UGI Corporation & Subsidiaries
1a	Gross receipts or sales	3,172,307,157.			3,172,307,157.
1b	Returns and allowances				
1c	Balance	3,172,307,157.			3,172,307,157.
2	Cost of goods sold	2,169,989,931.			2,169,989,931.
3	Gross profit	1,002,317,226.			1,002,317,226.
4	Dividends	NONE			NONE
5	Interest	8,595,059.			8,595,059.
6	Gross rents	2,626,037.			2,626,037.
7	Gross royalties				
8	Capital gain net income	1,888,165.			1,888,165.
9	Net gain or (loss) from Form 4797	1,812,652.			1,812,652.
10	Other income	37,502,433.			37,502,433.
11	Total income	1,054,741,572.			1,054,741,572.
12	Compensation of officers	15,814,794.			15,814,794.
13	Salaries and wages	148,813,333.			148,813,333.
14	Repairs and maintenance	105,047,330.			105,047,330.
15	Bad debts	12,703,966.			12,703,966.
16	Rents	3,738,825.			3,738,825.
17	Taxes and licenses	47,341,347.			47,341,347.
18	Interest	61,057,136.			61,057,136.
19	Charitable contributions	2,171,169.			2,171,169.
20	Depreciation	486,155,032.			486,155,032.
21	Depletion	434,685.		6.	434,691.
22	Advertising	2,305,105.			2,305,105.
23	Pension, profit-sharing etc., plans	7,219,411.			7,219,411.
24	Employee benefit programs	16,272,772.			16,272,772.
25	Domestic production activities deduction				
26	Other deductions	124,934,746.			124,934,746.
27	Total deductions	1,034,009,651.		6.	1,034,009,657.
28	Taxable income before NOL & Spec. Deductions	20,731,921.	NONE	-6.	20,731,915.
29	NOL,Spec. deductions	NONE			NONE
30	Taxable income	20,731,921.	NONE	-6.	20,731,915.

Consolidated Schedules

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		1120C Subgroup	1120 PC Subgroup
		23-2668356	03-0338831
1a	Gross receipts or sales	3,170,543,551.	1,763,606.
1b	Returns and allowances		
1c	Balance	3,170,543,551.	1,763,606.
2	Cost of goods sold	2,169,989,931.	
3	Gross profit	1,000,553,620.	1,763,606.
4	Dividends		NONE
5	Interest	8,525,326.	69,733.
6	Gross rents	2,626,037.	
7	Gross royalties		
8	Capital gain net income	1,320,254.	567,911.
9	Net gain or (loss) from Form 4797	1,812,652.	
10	Other income	37,502,433.	
11	Total income	1,052,340,322.	2,401,250.
12	Compensation of officers	15,814,794.	
13	Salaries and wages	148,813,333.	
14	Repairs and maintenance	105,047,330.	
15	Bad debts	12,703,966.	
16	Rents	3,738,825.	
17	Taxes and licenses	47,273,006.	68,341.
18	Interest	61,057,136.	
19	Charitable contributions	2,171,169.	
20	Depreciation	486,155,032.	
21	Depletion	434,685.	
22	Advertising	2,305,105.	
23	Pension, profit-sharing etc., plans	7,219,411.	
24	Employee benefit programs	16,272,772.	
25	Domestic production activities deduction		
26	Other deductions	122,362,563.	2,572,183.
27	Total deductions	1,031,369,127.	2,640,524.
28	Taxable income before NOL & Spec. Deductions	20,971,195.	-239,274.
29	NOL,Spec. deductions		NONE
30	Taxable income	20,971,195.	-239,274.

1120C Subgroup 23-2668356

Consolidated Schedules

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		Combined	UGI Eliminations	Adjustments	1120C Subgroup
1a	Gross receipts or sales	3,188,074,709.	-17,531,158.		3,170,543,551.
1b	Returns and allowances				
1c	Balance	3,188,074,709.	-17,531,158.		3,170,543,551.
2	Cost of goods sold	2,169,989,931.			2,169,989,931.
3	Gross profit	1,018,084,778.	-17,531,158.		1,000,553,620.
4	Dividends	172,192,094.	-172,192,094.		
5	Interest	9,390,075.	-864,749.		8,525,326.
6	Gross rents	2,626,037.			2,626,037.
7	Gross royalties				
8	Capital gain net income	3,114,546.		-1,794,292.	1,320,254.
9	Net gain or (loss) from Form 4797	18,360.		1,794,292.	1,812,652.
10	Other income	91,431,595.	-53,929,162.		37,502,433.
11	Total income	1,296,857,485.	-244,517,163.		1,052,340,322.
12	Compensation of officers	15,814,794.			15,814,794.
13	Salaries and wages	148,813,333.			148,813,333.
14	Repairs and maintenance	105,047,330.			105,047,330.
15	Bad debts	12,703,966.			12,703,966.
16	Rents	3,738,825.			3,738,825.
17	Taxes and licenses	47,273,006.			47,273,006.
18	Interest	65,536,607.	-4,479,471.		61,057,136.
19	Charitable contributions	2,171,169.			2,171,169.
20	Depreciation	486,155,032.			486,155,032.
21	Depletion	434,685.			434,685.
22	Advertising	2,305,105.			2,305,105.
23	Pension, profit-sharing etc., plans	7,219,411.			7,219,411.
24	Employee benefit programs	16,272,772.			16,272,772.
25	Domestic production activities deduction				
26	Other deductions	190,208,161.	-67,845,598.		122,362,563.
27	Total deductions	1,103,694,196.	-72,325,069.		1,031,369,127.
28	Taxable income before NOL & Spec. Deductions	193,163,289.	-172,192,094.		20,971,195.
29	NOL,Spec. deductions	172,192,094.	-172,192,094.		
30	Taxable income	20,971,195.			20,971,195.

1120C Subgroup 23-2668356

Consolidated Schedules 1120 Page 1	UGI Corporation 23-2668356	AmeriGas Propane, Inc. 23-2786294	AmeriGas Technology Group, Inc. 23-2861011	AmeriGas, Inc. 23-2716858	Ashtola Production Company 23-2101362	Eastfield International Holdings, Inc. 51-0385770	Energy Services Funding Corporation 23-3099149	EuroGas Holdings, Inc. 51-0392140
1a Gross receipts or sales	1,317,205,624.							
1b Returns and allowances								
1c Balance	1,317,205,624.							
2 Cost of goods sold	1,047,537,965.							
3 Gross profit	269,667,659.							
4 Dividends	125,392,667.			46,799,427.				
5 Interest	950,513.	3,310,345.					146,803.	
6 Gross rents	314.							
7 Gross royalties								
8 Capital gain net income	-3,849.	2,988,597.						
9 Net gain or (loss) from Form 4797	9,568.							
10 Other income	9,967,780.	61,124,202.					6,288,497.	
11 Total income	405,984,652.	67,423,144.		46,799,427.			6,435,300.	
12 Compensation of officers	10,382,560.	1,000,000.						
13 Salaries and wages	68,516,590.	3,771,331.						
14 Repairs and maintenance	536,678.							
15 Bad debts							133,448.	
16 Rents	2,095,323.							
17 Taxes and licenses	15,055,860.	3,350,579.		19,454.			530,719.	
18 Interest	1,836,560.	397.						
19 Charitable contributions	342,272.	51,089.						
20 Depreciation	120,835,792.	5,448.		4,038.				
21 Depletion	434,685.							
22 Advertising	911,567.							
23 Pension, profit-sharing etc., plans	3,309,919.							
24 Employee benefit programs	2,625,423.							
25 Domestic production activities deduction								
26 Other deductions	26,567,089.	-1,980,120.		2,337.	1,133.		989,349.	
27 Total deductions	253,450,318.	6,198,724.		25,829.	1,133.		1,653,516.	
28 Taxable income before NOL & Spec. Deductions	152,534,334.	61,224,420.	NONE	46,773,598.	-1,133.	NONE	4,781,784.	NONE
29 NOL,Spec. deductions	125,392,667.			46,799,427.				
30 Taxable income	27,141,667.	61,224,420.	NONE	-25,829.	-1,133.	NONE	4,781,784.	NONE

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Consolidated Schedules
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	Four Flags Drilling Company	Hellertown Pipeline Company	Homestead Holding Company	Newbury Holding Company	UGI Asset Management, Inc.	UGI Black Sea Enterprises, Inc.	UGI China, Inc.	UGI Development Company
	23-2178262	46-0490470	51-0467618	30-0170818	51-0380873	23-2800542	52-2095053	23-1650159
1a Gross receipts or sales								68,354,089.
1b Returns and allowances								
1c Balance								68,354,089.
2 Cost of goods sold								33,492,416.
3 Gross profit								34,861,673.
4 Dividends								
5 Interest				2,667,060.				16,549.
6 Gross rents								164.
7 Gross royalties								
8 Capital gain net income								
9 Net gain or (loss) from Form 4797								
10 Other income								1,864.
11 Total income				2,667,060.				34,880,250.
12 Compensation of officers								
13 Salaries and wages								2,235,033.
14 Repairs and maintenance								
15 Bad debts								
16 Rents			1,849.	1,849.				146,873.
17 Taxes and licenses				275.				745,479.
18 Interest			146,803.					
19 Charitable contributions								
20 Depreciation								18,659,593.
21 Depletion								
22 Advertising								
23 Pension, profit-sharing etc., plans								182,893.
24 Employee benefit programs								454,565.
25 Domestic production activities deduction								
26 Other deductions			5,852.	4,920.	438.			11,197,197.
27 Total deductions			154,504.	7,044.	438.			33,621,633.
28 Taxable income before NOL & Spec. Deductions	NONE	NONE	-154,504.	2,660,016.	-438.	NONE	NONE	1,258,617.
29 NOL,Spec. deductions								
30 Taxable income	NONE	NONE	-154,504.	2,660,016.	-438.	NONE	NONE	1,258,617.

Consolidated Schedules 1120 Page 1	UGI Energy Ventures, Inc 71-0992456	UGI Ethanol Development Company 23-2179048	UGI Europe, Inc. 23-3070112	UGI Hunlock Development Company 23-3051491	UGI HVAC Enterprises, Inc. 51-0375688	UGI International (China), Inc. 23-2867252	UGI International (Romania), Inc. 23-2837401	UGI LNG, Inc 51-0590685
1a Gross receipts or sales			608,031,462.		48,989,628.			13,268,374.
1b Returns and allowances								
1c Balance			608,031,462.		48,989,628.			13,268,374.
2 Cost of goods sold			560,160,232.		26,502,670.			
3 Gross profit			47,871,230.		22,486,958.			13,268,374.
4 Dividends								
5 Interest			2,274,940.					
6 Gross rents								
7 Gross royalties								
8 Capital gain net income								
9 Net gain or (loss) from Form 4797					-104,794.			
10 Other income			1,708,155.					
11 Total income			51,854,325.		22,382,164.			13,268,374.
12 Compensation of officers					150,692.			
13 Salaries and wages			27,574.		9,336,540.			
14 Repairs and maintenance								875,698.
15 Bad debts					307,574.			
16 Rents					607,622.			
17 Taxes and licenses			1,394,520.	90,141.	1,581,765.			381,681.
18 Interest			19,021,564.		508,444.			
19 Charitable contributions					3,722.			
20 Depreciation					1,394,725.			4,999,628.
21 Depletion								
22 Advertising					756,072.			
23 Pension, profit-sharing etc., plans					288,135.			
24 Employee benefit programs					2,554,377.			
25 Domestic production activities deduction								
26 Other deductions			26,192,856.		5,785,372.			2,219,399.
27 Total deductions			46,636,514.	90,141.	23,275,040.			8,476,406.
28 Taxable income before NOL & Spec. Deductions	NONE	NONE	5,217,811.	-90,141.	-892,876.	NONE	NONE	4,791,968.
29 NOL,Spec. deductions								
30 Taxable income	NONE	NONE	5,217,811.	-90,141.	-892,876.	NONE	NONE	4,791,968.

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Consolidated Schedules
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		UGI Penn HVAC Services, Inc 23-1946160	UGI Penn Natural Gas, Inc 56-2557139	UGI Petroleum Products of Delaware, Inc 51-0056772	UGI Properties, Inc. 23-2710207	UGI Romania, Inc. 23-2925615	UGI Storage Company 32-0309503	UGID Holding Company 51-0389590	UGI Utilities, Inc 23-1174060
1a	Gross receipts or sales		268,997,599.				10,923,406.		695,598,808.
1b	Returns and allowances								
1c	Balance		268,997,599.				10,923,406.		695,598,808.
2	Cost of goods sold		114,830,247.				-151,793.		336,960,990.
3	Gross profit		154,167,352.				11,075,199.		358,637,818.
4	Dividends								
5	Interest								23,865.
6	Gross rents				2,598,791.				26,768.
7	Gross royalties								
8	Capital gain net income		129,798.						
9	Net gain or (loss) from Form 4797						-20,360.		84,697.
10	Other income		1,063,212.				2,580.	3.	5,309,152.
11	Total income		155,360,362.		2,598,791.		11,057,419.	3.	364,082,300.
12	Compensation of officers								4,281,542.
13	Salaries and wages		14,940,307.						37,546,057.
14	Repairs and maintenance		32,497,109.		364,177.				62,818,234.
15	Bad debts		3,146,493.						7,191,798.
16	Rents							1,849.	592,022.
17	Taxes and licenses	15,229.	2,499,839.		237,699.		487,070.		14,192,614.
18	Interest		2,064,483.		776,195.				41,142,254.
19	Charitable contributions		186,236.		1,000.		200,000.		1,312,271.
20	Depreciation		132,465,877.		935,016.		1,754,496.		163,731,388.
21	Depletion								
22	Advertising								624,619.
23	Pension, profit-sharing etc., plans		1,660,382.						-798,807.
24	Employee benefit programs		2,331,577.						7,298,342.
25	Domestic production activities deduction								
26	Other deductions	328.	40,423,004.		383,362.		2,713,094.	5,182.	55,515,664.
27	Total deductions	15,557.	232,215,307.		2,697,449.		5,154,660.	7,031.	395,447,998.
28	Taxable income before NOL & Spec. Deductions	-15,557.	-76,854,945.	NONE	-98,658.	NONE	5,902,759.	-7,028.	-31,365,698.
29	NOL,Spec. deductions								
30	Taxable income	-15,557.	-76,854,945.	NONE	-98,658.	NONE	5,902,759.	-7,028.	-31,365,698.

Consolidated Schedules

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		UGI Central Penn Gas, Inc 23-1278755
1a	Gross receipts or sales	156,705,719.
1b	Returns and allowances	
1c	Balance	156,705,719.
2	Cost of goods sold	50,657,204.
3	Gross profit	106,048,515.
4	Dividends	
5	Interest	
6	Gross rents	
7	Gross royalties	
8	Capital gain net income	
9	Net gain or (loss) from Form 4797	49,249.
10	Other income	5,966,150.
11	Total income	112,063,914.
12	Compensation of officers	
13	Salaries and wages	12,439,901.
14	Repairs and maintenance	7,955,434.
15	Bad debts	1,924,653.
16	Rents	291,438.
17	Taxes and licenses	6,690,082.
18	Interest	39,907.
19	Charitable contributions	74,579.
20	Depreciation	41,369,031.
21	Depletion	
22	Advertising	12,847.
23	Pension, profit-sharing etc., plans	2,576,889.
24	Employee benefit programs	1,008,488.
25	Domestic production activities deduction	
26	Other deductions	20,181,705.
27	Total deductions	94,564,954.
28	Taxable income before NOL & Spec. Deductions	17,498,960.
29	NOL,Spec. deductions	
30	Taxable income	17,498,960.

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2018 or tax year beginning 10/01/2018, ending 09/30/2019

▶ Go to www.irs.gov/Form1120 for instructions and the latest information.

OMB No. 1545-0123 **2018**

A Check if:
1a Consolidated return (attach Form 851) X
b Life/nonlife consolidated return
2 Personal holding co. (attach Sch. PH)
3 Personal service corp (see instructions)
4 Schedule M-3 attached X

TYPE OR PRINT

Name: UGI Corporation & Subsidiaries
Number, street, and room or suite no. If a P.O. box, see instructions.: P.O. BOX 858
City or town, state, or province, country, and ZIP or foreign postal code: Valley Forge, PA 19482

B Employer identification number: 23-2668356
C Date incorporated: 12/01/1994
D Total assets (see instructions): $ 15,062,267,891.

E Check if: (1) Initial return (2) Final return (3) Name change (4) Address change

Income	1a	Gross receipts or sales	1a	2,839,287,655.		
	b	Returns and allowances	1b			
	c	Balance. Subtract line 1b from line 1a			1c	2,839,287,655.
	2	Cost of goods sold (attach Form 1125-A)			2	1,991,901,876.
	3	Gross profit. Subtract line 2 from line 1c			3	847,385,779.
	4	Dividends and inclusions (Schedule C, line 23, column (a))			4	64,230,131.
	5	Interest			5	11,880,967.
	6	Gross rents			6	243.
	7	Gross royalties			7	
	8	Capital gain net income (attach Schedule D (Form 1120))			8	NONE
	9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)			9	666,191.
	10	Other income (see instructions - attach statement) See Statement 3			10	155,282,009.
	11	**Total income.** Add lines 3 through 10 ▶			11	1,079,445,320.
Deductions (See instructions for limitations on deductions.)	12	Compensation of officers (see instructions - attach Form 1125-E) ▶			12	32,630,512.
	13	Salaries and wages (less employment credits)			13	142,535,634.
	14	Repairs and maintenance See Statement 6			14	139,040,169.
	15	Bad debts See Statement 8			15	16,097,683.
	16	Rents See Statement 9			16	4,254,660.
	17	Taxes and licenses See Statement 12			17	39,296,066.
	18	Interest (see instructions) See Statement 18			18	80,469,846.
	19	Charitable contributions See Statement 21			19	813,748.
	20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)			20	161,990,053.
	21	Depletion			21	343,824.
	22	Advertising See Statement 22			22	5,660,642.
	23	Pension, profit-sharing, etc., plans			23	-105,570,501.
	24	Employee benefit programs See Statement 23			24	16,170,680.
	25	Reserved for future use			25	
	26	Other deductions (attach statement) See Statement 24			26	270,540,959.
	27	**Total deductions.** Add lines 12 through 26 ▶			27	804,273,975.
	28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11			28	275,171,345.
	29a	Net operating loss deduction (see instructions)	29a			
	b	Special deductions (Schedule C, line 24, column (c))	29b	32,115,066.		
	c	Add lines 29a and 29b			29c	32,115,066.
Tax, Refundable Credits, and Payments	30	**Taxable income.** Subtract line 29c from line 28. See instructions			30	243,056,279.
	31	Total tax (Schedule J, Part I, line 11)			31	44,979,282.
	32	2018 net 965 tax liability paid (Schedule J, Part II, line 12)			32	
	33	Total payments, credits, and section 965 net tax liability (Schedule J, Part III, line 23)			33	48,882,927.
	34	Estimated tax penalty. See instructions. Check if Form 2220 is attached ▶ ☐			34	
	35	**Amount owed.** If line 33 is smaller than the total of lines 31, 32, and 34, enter amount owed			35	
	36	**Overpayment.** If line 33 is larger than the total of lines 31, 32, and 34, enter amount overpaid			36	3,903,645.
	37	Enter amount from line 36 you want: **Credited to 2019 estimated tax** ▶ 3,903,645. **Refunded** ▶			37	

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer: MICHAEL R PEARSON | Date: 07/15/2020 | Title: ASSISTANT TREASURER

May the IRS discuss this return with the preparer shown below? See instructions. ☐ Yes ☐ No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN

Firm's name ▶ | Firm's EIN ▶
Firm's address ▶ | Phone no.

For Paperwork Reduction Act Notice, see separate instructions. Form **1120** (2018)

JSA
8C1110 2.000

UGI Corporation & Subsidiaries 23-2668356
Form 1120 (2018) Page 2

Schedule C Dividends, Inclusions, and Special Deductions (see instructions)	(a) Dividends and inclusions	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)	NONE	50	NONE
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		65	
3 Dividends on certain debt-financed stock of domestic and foreign corporations		see instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		23.3	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		26.7	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		50	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		65	
8 Dividends from wholly owned foreign subsidiaries		100	
9 **Subtotal.** Add lines 1 through 8. See instructions for limitations	NONE	see instructions	NONE
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members		100	
12 Dividends from certain FSCs		100	
13 Foreign-source portion of dividends received from a specified 10%-owned foreign corporation (excluding hybrid dividends) (see instructions)		100	
14 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, 12, or 13 (including any hybrid dividends)			
15 Section 965(a) inclusion		see instructions	
16 a Subpart F inclusions derived from the sale by a controlled foreign corporation (CFC) of the stock of a lower-tier foreign corporation treated as a dividend (attach Form(s) 5471) (see instructions)		100	
b Subpart F inclusions derived from hybrid dividends of tiered corporations (attach Form(s) 5471) (see instructions)			
c Other inclusions from CFCs under subpart F not included on line 15, 16a, 16b, or 17 (attach Form(s) 5471) (see instructions)			
17 Global Intangible Low-Taxed Income (GILTI) (attach Form(s) 5471 and Form 8992)	44,754,641.		
18 Gross-up for foreign taxes deemed paid	19,475,491.		
19 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
20 Other dividends			
21 Deduction for dividends paid on certain preferred stock of public utilities			
22 Section 250 deduction (attach Form 8993)			32,115,066.
23 **Total dividends and inclusions.** Add lines 9 through 20. Enter here and on page 1, line 4	64,230,131.		
24 **Total special deductions.** Add lines 9 through 22, column (c). Enter here and on page 1, line 29b			32,115,066.

Form **1120** (2018)

UGI Corporation & Subsidiaries 23-2668356

Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ▶ ☐				
2	Income tax. See instructions			2	51,041,819.
3	Base erosion minimum tax (attach Form 8991)			3	
4	Add lines 2 and 3			4	51,041,819.
5a	Foreign tax credit (attach Form 1118)	5a	5,904,583.		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c	157,954.		
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	6,062,537.
7	Subtract line 6 from line 4			7	44,979,282.
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement)	9f			
10	**Total.** Add lines 9a through 9f			10	
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	44,979,282.

Part II-Section 965 Payments (see instructions)

12	2018 net 965 tax liability paid from Form 965-B, Part II, column (k), line 2. Enter here and on page 1, line 32	12	

Part III-Payments, Refundable Credits, and Section 965 Net Tax Liability

13	2017 overpayment credited to 2018			13	41,374,376.
14	2018 estimated tax payments			14	7,500,000.
15	2018 refund applied for on Form 4466			15	( )
16	Combine lines 13, 14, and 15			16	48,874,376.
17	Tax deposited with Form 7004			17	
18	Withholding (see instructions)			18	
19	**Total payments.** Add lines 16, 17, and 18			19	48,874,376.
20	Refundable credits from:				
a	Form 2439	20a			
b	Form 4136	20b	8,551.		
c	Form 8827, line 8c	20c			
d	Other (attach statement - see instructions)	20d			
21	**Total credits.** Add lines 20a through 20d			21	8,551.
22	2018 net 965 tax liability from Form 965-B, Part I, column (d), line 2. See instructions			22	
23	**Total payments, credits, and section 965 net tax liability.** Add lines 19, 21, and 22. Enter here and on page 1, line 33			23	48,882,927.

UGI Corporation & Subsidiaries 23-2668356

Form 1120 (2018) Page 4

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a [ ] Cash b [X] Accrual c [ ] Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ N/A		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X
5	At the end of the tax year, did the corporation:		
a	Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851**, Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock
See Statement 43			

		Yes	No
b	Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital
See Statement 45			

		Yes	No
6	During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316. If "Yes," file **Form 5452**, Corporate Report of Nondividend Distributions. See the instructions for Form 5452. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		X
7	At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of the total voting power of all classes of the corporation's stock entitled to vote or at least 25% of the total value of all classes of the corporation's stock? For rules of attribution, see section 318. If "Yes," enter: (a) Percentage owned ▶ ______ and (b) Owner's country ▶ ______ (c) The corporation may have to file **Form 5472**, Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶		X
8	Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ [ ] If checked, the corporation may have to file **Form 8281**, Information Return for Publicly Offered Original Issue Discount Instruments.		
9	Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $		
10	Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶		
11	If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here (see instructions) ▶ [ ] If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election will not be valid.		
12	Enter the available NOL carryover from prior tax years (do not reduce it by any deduction reported on page 1, line 29a.) ▶ $		

UGI Corporation & Subsidiaries 23-2668356

Schedule K **Other Information** *(continued from page 4)*

		Yes	No
13	Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year **and** its total assets at the end of the tax year less than $250,000?		X
	If "Yes," the corporation is not required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $		
14	Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions	X	
	If "Yes," complete and attach Schedule UTP.		
15a	Did the corporation make any payments in 2018 that would require it to file Form(s) 1099?		X
b	If "Yes," did or will the corporation file required Forms 1099?		
16	During this tax year, did the corporation have an 80% or more change in ownership, including a change due to redemption of its own stock?		X
17	During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18	Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19	During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?		X
20	Is the corporation operating on a cooperative basis?		X
21	During the tax year, did the corporation pay or accrue any interest or royalty for which the deduction is not allowed under section 267A? See instructions		X
	If "Yes," enter the total amount of the disallowed deductions ▶ $		
22	Does the corporation have gross receipts of at least $500 million in any of the 3 preceding tax years? (See sections 59A(e)(2) and (3))		X
	If "Yes," complete and attach Form 8991.		
23	Did the corporation have an election under section 163(j) for any real property trade or business or any farming business in effect during the tax year? See instructions		X
24	Does the corporation satisfy **one** of the following conditions and the corporation does not own a pass-through entity with current year, or prior year carryover, excess business interest expense? See instructions		X
a	The corporation's aggregate average annual gross receipts (determined under section 448(c)) for the 3 tax years preceding the current tax year do not exceed $25 million, and the corporation is not a tax shelter, or		
b	The corporation only has business interest expense from (1) an electing real property trade or business, (2) an electing farming business, or (3) certain utility businesses under section 163(j)(7).		
	If "No," complete and attach Form 8990.		
25	Is the corporation attaching Form 8996 to certify as a Qualified Opportunity Fund?		X
	If "Yes," enter amount from Form 8996, line 13 ▶ $		

UGI Corporation & Subsidiaries 23-2668356

Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	(b)	End of tax year (c)	(d)
1 Cash		258,428,383.		305,774,908.
2a Trade notes and accounts receivable	177,965,878.		210,738,611.	
b Less allowance for bad debts	(11,082,325.)	166,883,553.	(9,470,663.)	201,267,948.
3 Inventories		98,639,879.		79,648,166.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)	Stmt 52	117,569,594.		675,156,924.
7 Loans to shareholders				
8 Mortgage and real estate loans				
9 Other investments (attach statement)	Stmt 60	2,139,770,478.		7,795,717,410.
10a Buildings and other depreciable assets	4,813,984,988.		5,900,064,945.	
b Less accumulated depreciation	(1,299,453,283.)	3,514,531,705.	(1,403,980,859.)	4,496,084,086.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)		24,935,559.		18,851,956.
13a Intangible assets (amortizable only)	223,200,277.		815,812,704.	
b Less accumulated amortization	(17,260,508.)	205,939,769.	(20,130,109.)	795,682,595.
14 Other assets (attach statement)	Stmt 64	455,131,456.		694,083,898.
15 Total assets		6,981,830,376.		15,062,267,891.
Liabilities and Shareholders' Equity				
16 Accounts payable		215,501,970.		178,898,840.
17 Mortgages, notes, bonds payable in less than 1 year		201,322,652.		481,378,465.
18 Other current liabilities (attach statement)	Stmt 68	150,819,259.		353,099,255.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		1,436,924,917.		3,248,821,335.
21 Other liabilities (attach statement)	Stmt 78	1,345,179,912.		1,375,731,502.
22 Capital stock: a Preferred stock				
b Common stock			64,140,213.	64,140,213.
23 Additional paid-in capital		1,199,506,775.		7,593,567,477.
24 Retained earnings - Appropriated (attach statement)				2,191,068.
25 Retained earnings - Unappropriated		2,612,429,855.		2,017,154,023.
26 Adjustments to shareholders' equity (attach statement)		-159,798,285.		-236,572,304.
27 Less cost of treasury stock		(20,056,679.)		(16,141,983.)
28 Total liabilities and shareholders' equity		6,981,830,376.		15,062,267,891.

Schedule M-1 Reconciliation of Income (Loss) per Books With Income per Return

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 Analysis of Unappropriated Retained Earnings per Books (Line 25, Schedule L)

1 Balance at beginning of year	2,612,429,855.	5 Distributions: a Cash	579,446,847.
2 Net income (loss) per books	299,004,527.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize) Stmt 88	20,197,008.
See Statement 84	264,759,103.	7 Add lines 5 and 6	599,643,855.
4 Add lines 1, 2, and 3	3,176,193,485.	8 Balance at end of year (line 4 less line 7)	2,576,549,630.

SCHEDULE M-3 (Form 1120)
Department of the Treasury
Internal Revenue Service

Net Income (Loss) Reconciliation for Corporations With Total Assets of $10 Million or More

▶ Attach to Form 1120 or 1120-C.
▶ Go to *www.irs.gov/Form1120* for instructions and the latest information.

OMB No. 1545-0123
2018

Name of corporation (common parent, if consolidated return): UGI Corporation
Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Non-consolidated return (2) [ ] Consolidated return (Form 1120 only)
(3) [X] Mixed 1120/L/PC group (4) [ ] Dormant subsidiaries schedule attached

Part I Financial Information and Net Income (Loss) Reconciliation (see instructions)

1 a Did the corporation file SEC Form 10-K for its income statement period ending with or within this tax year?
[X] **Yes.** Skip lines 1b and 1c and complete lines 2a through 11 with respect to that SEC Form 10-K.
[ ] **No.** Go to line 1b. See instructions if multiple non-tax-basis income statements are prepared.

b Did the corporation prepare a certified audited non-tax-basis income statement for that period?
[ ] **Yes.** Skip line 1c and complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Go to line 1c.

c Did the corporation prepare a non-tax-basis income statement for that period?
[ ] **Yes.** Complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Skip lines 2a through 3c and enter the corporation's net income (loss) per its books and records on line 4a.

2 a Enter the income statement period: Beginning 10/01/2018 Ending 09/30/2019

b Has the corporation's income statement been restated for the income statement period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

c Has the corporation's income statement been restated for any of the five income statement periods immediately preceding the period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

3 a Is any of the corporation's voting common stock publicly traded?
[X] **Yes.**
[ ] **No.** If "No," go to line 4a.

b Enter the symbol of the corporation's primary U.S. publicly traded voting common stock: UGI

c Enter the nine-digit CUSIP number of the corporation's primary publicly traded voting common stock: 902681105

4 a	Worldwide consolidated net income (loss) from income statement source identified in Part I, line 1	4a	256,201,950.
b	Indicate accounting standard used for line 4a (see instructions): (1) [X] GAAP (2) [ ] IFRS (3) [ ] Statutory (4) [ ] Tax-basis (5) [ ] Other (specify)		
5 a	Net income from nonincludible foreign entities (attach statement) Stmt. 91.	5a	(25,674,929.
b	Net loss from nonincludible foreign entities (attach statement and enter as a positive amount) Stmt. 91.	5b	68,649,330.
6 a	Net income from nonincludible U.S. entities (attach statement)	6a	( )
b	Net loss from nonincludible U.S. entities (attach statement and enter as a positive amount)	6b	
7 a	Net income (loss) of other includible foreign disregarded entities (attach statement)	7a	
b	Net income (loss) of other includible U.S. disregarded entities (attach statement)	7b	
c	Net income (loss) of other includible entities (attach statement)	7c	
8	Adjustment to eliminations of transactions between includible entities and nonincludible entities (attach statement)	8	
9	Adjustment to reconcile income statement period to tax year (attach statement)	9	
10 a	Intercompany dividend adjustments to reconcile to line 11 (attach statement)	10a	
b	Other statutory accounting adjustments to reconcile to line 11 (attach statement)	10b	
c	Other adjustments to reconcile to amount on line 11 (attach statement) Stmt. 92.	10c	-171,824.
11	**Net income (loss) per income statement of includible corporations.** Combine lines 4 through 10	11	299,004,527.

Note: Part I, line 11, must equal Part II, line 30, column (a), or Schedule M-1, line 1 (see instructions).

12 Enter the total amount (not just the corporation's share) of the assets and liabilities of all entities included or removed on the following lines.

		Total Assets	Total Liabilities
a	Included on Part I, line 4 ▶		
b	Removed on Part I, line 5 ▶		
c	Removed on Part I, line 6 ▶		
d	Included on Part I, line 7 ▶		

Schedule M-3 (Form 1120) 2018 Page **2**

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [X] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): Nonlife Consolidation

Employer identification number

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Gross-up for foreign taxes deemed paid				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25				
27 **Total expense/deduction items** (from Part III, line 39)				
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28	299,501,757.	25,416,023.	-55,505,710.	269,412,070.
b PC insurance subgroup reconciliation totals	-497,230.	-125,858.	-127,596.	-750,684.
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	299,004,527.	25,290,165.	-55,633,306.	268,661,386.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2018 Page **2**

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): 1120 Subgroup

Employer identification number:

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions			44,754,641.	44,754,641.
4 Gross-up for foreign taxes deemed paid		19,475,491.		19,475,491.
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation	118,129,976.		-118,129,976.	
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	48,211,641.	46,285,363.		94,497,004.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	13,584,507.	-1,691,682.	26,150.	11,918,975.
14 Total accrual to cash adjustment				
15 Hedging transactions	11,303,457.	112,011,876.		123,315,333.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(1,915,447,223.)	-43,041,908.		(1,958,489,131.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue	-956,883.	753,778.		-203,105.
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	-657,020.	809,155.	-13,997.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		18,310.		18,310.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory			608,356.	608,356.
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	3,442,601.	6,745,194.	-4,502,331.	5,685,464.
26 **Total income (loss) items.** Combine lines 1 through 25	-1,722,388,944.	141,365,577.	-77,257,157.	-1,658,280,524.
27 **Total expense/deduction items** (from Part III, line 39)	-375,190,493.	-115,949,554.	21,751,447.	-469,388,600.
28 Other items with no differences	2,397,081,194.			2,397,081,194.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	299,501,757.	25,416,023.	-55,505,710.	269,412,070.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	299,501,757.	25,416,023.	-55,505,710.	269,412,070.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) 2018 Page **3**

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): 1120 Subgroup

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	52,848,854.		-52,848,863.	
2 U.S. deferred income tax expense	1,712,042.		-1,712,033.	
3 State and local current income tax expense	12,490,459.	-210,067.		12,280,392.
4 State and local deferred income tax expense	2,802,740.	-2,802,740.		
5 Foreign current income tax expense (other than foreign withholding taxes)	-12,082,950.	12,082,888.		-62.
6 Foreign deferred income tax expense	-18,366,375.		18,366,375.	
7 Foreign withholding taxes				
8 Interest expense (see instructions)	74,735,365.	99,020.		74,834,385.
9 Stock option expense	6,214,221.	-5,620,605.	14,291,165.	14,884,781.
10 Other equity-based compensation	3,200,064.	7,429,253.	4,917,583.	15,546,900.
11 Meals and entertainment	1,966,259.		-886,534.	1,079,725.
12 Fines and penalties	10,685.		-5,083.	5,602.
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation	4,599,963.		-2,000,739.	2,599,224.
16 Pension and profit-sharing	14,380,505.	-117,200,504.	-365,012.	-103,185,011.
17 Other post-retirement benefits	-2,015,643.	-371,560.		-2,387,203.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	780,219.	44,281.	-10,800.	813,700.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction (see instructions)				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs	15,542,434.	520,880.		16,063,314.
26 Amortization/impairment of goodwill		13,821,831.		13,821,831.
27 Amortization of acquisition, reorganization, and start-up costs		97,389.		97,389.
28 Other amortization or impairment write-offs	16,364,235.	3,018,887.		19,383,122.
29 Reserved				
30 Depletion		343,824.		343,824.
31 Depreciation	134,608,323.	27,377,557.		161,985,880.
32 Bad debt expense	14,636,234.	1,461,449.		16,097,683.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)	17,783.	372,678.		390,461.
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Section 162(r) - FDIC premiums paid by certain large financial institutions (see instructions)				
38 Other expense/deduction items with differences (attach statement)	50,745,076.	175,485,093.	-1,497,506.	224,732,663.
39 **Total expense/deduction items.** Combine lines 1 through 38. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	375,190,493.	115,949,554.	-21,751,447.	469,388,600.

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return): 1120-PC Subgroup

Employer identification number:

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 11)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Gross-up for foreign taxes deemed paid				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions (attach statement)				
13 Interest income (attach Form 8916-A)	45,706.			45,706.
14 Hedging transactions				
15 Mark-to-market income (loss)				
16 Premium income (attach statement)	596,843.	-79,124.		517,719.
17 Sale versus lease (for sellers and/or lessors)				
18 Section 481(a) adjustments				
19 Income from a special loss discount account				
20 Income recognition from long-term contracts				
21 Original issue discount and other imputed interest				
22 Reserved for future use				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than pass-through entities	86,195.		-86,195.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities			92,838.	92,838.
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	728,744.	-79,124.	6,643.	656,263.
27 **Total expense/deduction items** (from Part III, line 40)	-1,180,370.	-46,734.	-134,239.	-1,361,343.
28 Other items with no differences	-45,604.			-45,604.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	-497,230.	-125,858.	-127,596.	-750,684.
b 1120 subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	-497,230.	-125,858.	-127,596.	-750,684.

Note: Line 30, column (a), must equal the amount on Part I, line 11, and column (d) must equal Form 1120-PC, Schedule A, line 35.

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return): 1120-PC Subgroup

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-141,367.		141,367.	
2 U.S. deferred income tax expense	7,128.		-7,128.	
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Stock option expense				
9 Other equity-based compensation				
10 Meals and entertainment				
11 Fines and penalties				
12 Judgments, damages, awards, and similar costs				
13 Parachute payments				
14 Compensation with section 162(m) limitation				
15 Pension and profit-sharing				
16 Other post-retirement benefits				
17 Deferred compensation				
18 Charitable contribution of cash and tangible property				
19 Charitable contribution of intangible property				
20 Charitable contribution limitation/carryforward				
21 Write-off of premium receivables				
22 Guarantee fund assessments				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization of acquisition, reorganization, and start-up costs				
27 Amortization/impairment of goodwill, insurance in force, and ceding commissions	18,368.	-18,368.		
28 Other amortization or impairment write-offs		25,622.		25,622.
29 Discounting of unpaid losses (section 846) (attach statement)	1,297,483.	37,102.		1,334,585.
30 Reduction of loss deduction (section 832(b)(5)(B))				
31 Depreciation				
32 Bad debt expense and/or agency balances written off				
33 Reserved for future use				
34 Corporate-owned life insurance premiums				
35 Purchase versus lease (for purchasers and/or lessees)				
36 Interest expense (attach Form 8916-A)				
37 Research and development costs				
38 Section 118 exclusion (attach statement)				
39 Other expense/deduction items with differences (attach statement)	-1,242.	2,378.		1,136.
40 **Total expense/deduction items.** Combine lines 1 through 39. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	1,180,370.	46,734.	134,239.	1,361,343.

UGI Corporation & Subsidiaries 23-2668356

Consolidated Schedules
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		Combined	UGI Eliminations Top Consolidation	Adjustments	UGI Corporation & Subsidiaries
1a	Gross receipts or sales	2,839,287,655.			2,839,287,655.
1b	Returns and allowances				
1c	Balance	2,839,287,655.			2,839,287,655.
2	Cost of goods sold	1,991,901,876.			1,991,901,876.
3	Gross profit	847,385,779.			847,385,779.
4	Dividends	64,230,131.			64,230,131.
5	Interest	11,880,967.			11,880,967.
6	Gross rents	243.			243.
7	Gross royalties				
8	Capital gain net income	-5,861,948.		5,861,948.	NONE
9	Net gain or (loss) from Form 4797	18,602.		647,589.	666,191.
10	Other income	155,282,009.			155,282,009.
11	Total income	1,072,935,783.		6,509,537.	1,079,445,320.
12	Compensation of officers	32,630,512.			32,630,512.
13	Salaries and wages	142,535,634.			142,535,634.
14	Repairs and maintenance	139,040,169.			139,040,169.
15	Bad debts	16,097,683.			16,097,683.
16	Rents	4,254,660.			4,254,660.
17	Taxes and licenses	39,296,066.			39,296,066.
18	Interest	80,469,846.			80,469,846.
19	Charitable contributions	813,748.			813,748.
20	Depreciation	161,990,053.			161,990,053.
21	Depletion	343,819.		5.	343,824.
22	Advertising	5,660,642.			5,660,642.
23	Pension, profit-sharing etc., plans	-105,570,501.			-105,570,501.
24	Employee benefit programs	16,170,680.			16,170,680.
25	Reserved for future use				
26	Other deductions	270,540,959.			270,540,959.
27	Total deductions	804,273,970.		5.	804,273,975.
28	Taxable income before NOL & Spec. Deductions	268,661,813.	NONE	6,509,532.	275,171,345.
29	NOL,Spec. deductions	32,115,066.			32,115,066.
30	Taxable income	236,546,747.	NONE	6,509,532.	243,056,279.

UGI Corporation & Subsidiaries 23-2668356

Consolidated Schedules

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		1120C Subgroup	1120 PC Subgroup
		23-2668356	03-0338831
1a	Gross receipts or sales	2,838,769,936.	517,719.
1b	Returns and allowances		
1c	Balance	2,838,769,936.	517,719.
2	Cost of goods sold	1,991,901,876.	
3	Gross profit	846,868,060.	517,719.
4	Dividends	64,230,131.	NONE
5	Interest	11,835,261.	45,706.
6	Gross rents	243.	
7	Gross royalties		
8	Capital gain net income	-5,954,786.	92,838.
9	Net gain or (loss) from Form 4797	18,602.	
10	Other income	155,282,009.	
11	Total income	1,072,279,520.	656,263.
12	Compensation of officers	32,630,512.	
13	Salaries and wages	142,535,634.	
14	Repairs and maintenance	139,040,169.	
15	Bad debts	16,097,683.	
16	Rents	4,254,660.	
17	Taxes and licenses	39,335,704.	-39,638.
18	Interest	80,469,846.	
19	Charitable contributions	813,748.	
20	Depreciation	161,990,053.	
21	Depletion	343,819.	
22	Advertising	5,660,642.	
23	Pension, profit-sharing etc., plans	-105,570,501.	
24	Employee benefit programs	16,170,680.	
25	Reserved for future use		
26	Other deductions	269,094,374.	1,446,585.
27	Total deductions	802,867,023.	1,406,947.
28	Taxable income before NOL & Spec. Deductions	269,412,497.	-750,684.
29	NOL,Spec. deductions	32,115,066.	NONE
30	Taxable income	237,297,431.	-750,684.

1120C Subgroup 23-2668356

Consolidated Schedules
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		Combined	UGI Eliminations	Adjustments	1120C Subgroup
1a	Gross receipts or sales	3,165,142,603.	-326,372,667.		2,838,769,936.
1b	Returns and allowances				
1c	Balance	3,165,142,603.	-326,372,667.		2,838,769,936.
2	Cost of goods sold	2,301,380,372.	-309,478,496.		1,991,901,876.
3	Gross profit	863,762,231.	-16,894,171.		846,868,060.
4	Dividends	353,124,504.	-288,894,373.		64,230,131.
5	Interest	14,118,570.	-2,283,309.		11,835,261.
6	Gross rents	243.			243.
7	Gross royalties				
8	Capital gain net income	-5,954,786.			-5,954,786.
9	Net gain or (loss) from Form 4797	18,602.			18,602.
10	Other income	155,282,009.			155,282,009.
11	Total income	1,380,351,373.	-308,071,853.		1,072,279,520.
12	Compensation of officers	32,630,512.			32,630,512.
13	Salaries and wages	142,535,634.			142,535,634.
14	Repairs and maintenance	139,040,169.			139,040,169.
15	Bad debts	16,097,683.			16,097,683.
16	Rents	4,254,660.			4,254,660.
17	Taxes and licenses	39,335,704.			39,335,704.
18	Interest	94,560,996.	-14,091,150.		80,469,846.
19	Charitable contributions	813,748.			813,748.
20	Depreciation	161,990,476.		-423.	161,990,053.
21	Depletion	343,819.			343,819.
22	Advertising	5,660,642.			5,660,642.
23	Pension, profit-sharing etc., plans	-106,484,504.	914,003.		-105,570,501.
24	Employee benefit programs	16,170,680.			16,170,680.
25	Reserved for future use				
26	Other deductions	275,094,707.	-6,000,333.		269,094,374.
27	Total deductions	822,044,926.	-19,177,480.	-423.	802,867,023.
28	Taxable income before NOL & Spec. Deductions	558,306,447.	-288,894,373.	423.	269,412,497.
29	NOL,Spec. deductions	321,009,439.	-288,894,373.		32,115,066.
30	Taxable income	237,297,008.		423.	237,297,431.

1120C Subgroup 23-2668356

Consolidated Schedules
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		UGI Corporation 23-2668356	AmeriGas Propane, Inc. 23-2786294	AmeriGas Technology Group, Inc. 23-2861011	AmeriGas, Inc. 23-2716858	Ashtola Production Company 23-2101362	Eastfield International Holdings, Inc. 51-0385770	Energy Services Funding Corporation 23-3099149	EuroGas Holdings, Inc. 51-0392140
1a	Gross receipts or sales	1,477,045,886.							
1b	Returns and allowances								
1c	Balance	1,477,045,886.							
2	Cost of goods sold	1,240,163,699.							
3	Gross profit	236,882,187.							
4	Dividends	176,137,931.			112,756,442.				
5	Interest	2,260,440.						264,383.	
6	Gross rents	243.							
7	Gross royalties								
8	Capital gain net income	-6,605,189.	650,403.						
9	Net gain or (loss) from Form 4797	4,500.							
10	Other income	32,512,368.	100,620,571.			17.		6,929,400.	
11	Total income	441,192,480.	101,270,974.		112,756,442.	17.		7,193,783.	
12	Compensation of officers	24,018,155.	599,224.						
13	Salaries and wages	53,002,525.	1,221,421.						
14	Repairs and maintenance	21,284,458.							
15	Bad debts							228,785.	
16	Rents	1,593,944.							
17	Taxes and licenses	8,774,131.	5,494,143.		18,662.			573,182.	
18	Interest	37,858,636.						1,045,479.	
19	Charitable contributions	563,180.	44,281.						
20	Depreciation	45,874,235.	5,447.		4,038.				
21	Depletion	343,819.							
22	Advertising	824,415.							
23	Pension, profit-sharing etc., plans	1,030,128.							
24	Employee benefit programs	3,835,494.							
25	Reserved for future use								
26	Other deductions	28,441,505.	26,794.		2,858.	1,115.		284,807.	
27	Total deductions	227,444,625.	7,391,310.		25,558.	1,115.		2,132,253.	
28	Taxable income before NOL & Spec. Deductions	213,747,855.	93,879,664.	NONE	112,730,884.	-1,098.	NONE	5,061,530.	NONE
29	NOL,Spec. deductions	176,137,931.			112,756,442.				
30	Taxable income	37,609,924.	93,879,664.	NONE	-25,558.	-1,098.	NONE	5,061,530.	NONE

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Consolidated Schedules 1120 Page 1	Four Flags Drilling Company 23-2178262	Hellertown Pipeline Company 46-0490470	Homestead Holding Company 51-0467618	Newbury Holding Company 30-0170818	UGI Asset Management, Inc. 51-0380873	UGI Black Sea Enterprises, Inc. 23-2800542	UGI China, Inc. 52-2095053	UGI Development Company 23-1650159
1a Gross receipts or sales								45,188,087.
1b Returns and allowances								
1c Balance								45,188,087.
2 Cost of goods sold								19,979,201.
3 Gross profit								25,208,886.
4 Dividends								
5 Interest				3,260,509.				80,453.
6 Gross rents								
7 Gross royalties								
8 Capital gain net income								
9 Net gain or (loss) from Form 4797								
10 Other income					4.			-17,989.
11 Total income				3,260,509.	4.			25,271,350.
12 Compensation of officers								
13 Salaries and wages								2,128,815.
14 Repairs and maintenance								5,948,430.
15 Bad debts								
16 Rents			2,252.	2,252.				477,283.
17 Taxes and licenses	45.			310.				188,151.
18 Interest			264,383.					
19 Charitable contributions								
20 Depreciation								16,045,554.
21 Depletion								
22 Advertising								
23 Pension, profit-sharing etc., plans								88,642.
24 Employee benefit programs								421,787.
25 Reserved for future use								
26 Other deductions			6,421.	4,902.	453.			5,896,240.
27 Total deductions	45.		273,056.	7,464.	453.			31,194,902.
28 Taxable income before NOL & Spec. Deductions	-45.	NONE	-273,056.	3,253,045.	-449.	NONE	NONE	-5,923,552.
29 NOL, Spec. deductions								
30 Taxable income	-45.	NONE	-273,056.	3,253,045.	-449.	NONE	NONE	-5,923,552.

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Consolidated Schedules
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	UGI Energy Ventures, Inc 71-0992456	UGI Ethanol Development Company 23-2179048	UGI Europe, Inc. 23-3070112	UGI Hunlock Development Company 23-3051491	UGI HVAC Enterprises, Inc. 51-0375688	UGI International (China), Inc. 23-2867252	UGI International (Romania), Inc. 23-2837401	UGI LNG, Inc 51-0590685
1a Gross receipts or sales			509,962,387.		53,843,013.			13,269,093.
1b Returns and allowances								
1c Balance			509,962,387.		53,843,013.			13,269,093.
2 Cost of goods sold			494,317,028.		30,676,490.			
3 Gross profit			15,645,359.		23,166,523.			13,269,093.
4 Dividends			64,230,131.					
5 Interest			6,506,750.		15,437.			60,392.
6 Gross rents								
7 Gross royalties								
8 Capital gain net income								
9 Net gain or (loss) from Form 4797					13,810.			
10 Other income			5,251,834.					
11 Total income			91,634,074.		23,195,770.			13,329,485.
12 Compensation of officers					505,917.			
13 Salaries and wages					9,188,271.			
14 Repairs and maintenance								865,565.
15 Bad debts					35,936.			
16 Rents					595,861.			
17 Taxes and licenses			1,150,291.		1,548,969.			235,830.
18 Interest			5,293,218.		189,433.			
19 Charitable contributions					4,288.			
20 Depreciation			423.		1,323,355.			4,588,740.
21 Depletion								
22 Advertising					1,942,873.			
23 Pension, profit-sharing etc., plans					721,868.			
24 Employee benefit programs					2,725,627.			
25 Reserved for future use								
26 Other deductions			17,308,534.		4,718,092.			2,108,900.
27 Total deductions			23,752,466.		23,500,490.			7,799,035.
28 Taxable income before NOL & Spec. Deductions	NONE	NONE	67,881,608.	NONE	-304,720.	NONE	NONE	5,530,450.
29 NOL, Spec. deductions			32,115,066.					
30 Taxable income	NONE	NONE	35,766,542.	NONE	-304,720.	NONE	NONE	5,530,450.

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Consolidated Schedules
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		UGI Penn HVAC Services, Inc	UGI Petroleum Products of Delaware, Inc	UGI Properties, Inc.	UGI Romania, Inc.	UGI Storage Company	UGID Holding Company	UGI Utilities, Inc	AmeriGas Propane Holdings, Inc
		23-1946160	51-0056772	23-2710207	23-2925615	32-0309503	51-0389590	23-1174060	83-4160550
1a	Gross receipts or sales			2,322,939.		8,938,438.		1,054,572,760.	
1b	Returns and allowances								
1c	Balance			2,322,939.		8,938,438.		1,054,572,760.	
2	Cost of goods sold					-29,687.		516,273,641.	
3	Gross profit			2,322,939.		8,968,125.		538,299,119.	
4	Dividends								
5	Interest					51,518.		1,618,688.	
6	Gross rents								
7	Gross royalties								
8	Capital gain net income								
9	Net gain or (loss) from Form 4797							292.	
10	Other income			18,565.		6,907.		9,960,332.	
11	Total income			2,341,504.		9,026,550.		549,878,431.	
12	Compensation of officers							7,507,216.	
13	Salaries and wages							76,994,602.	
14	Repairs and maintenance			341,644.		296,578.		110,303,494.	
15	Bad debts							15,832,962.	
16	Rents						2,252.	1,580,816.	
17	Taxes and licenses	-3,210.	3.	118,328.		86,840.		21,240,127.	-90,098.
18	Interest			757,703.				49,152,144.	
19	Charitable contributions			2,000.		200,000.		-1.	
20	Depreciation			478,018.		1,752,147.		91,918,519.	
21	Depletion								
22	Advertising							2,893,354.	
23	Pension, profit-sharing etc., plans							-108,325,142.	
24	Employee benefit programs							9,187,772.	
25	Reserved for future use								
26	Other deductions			398,575.		2,226,399.	5,437.	213,663,675.	
27	Total deductions	-3,210.	3.	2,096,268.		4,561,964.	7,689.	491,949,538.	-90,098.
28	Taxable income before NOL & Spec. Deductions	3,210.	-3.	245,236.	NONE	4,464,586.	-7,689.	57,928,893.	90,098.
29	NOL,Spec. deductions								
30	Taxable income	3,210.	-3.	245,236.	NONE	4,464,586.	-7,689.	57,928,893.	90,098.

Form **1120** Department of the Treasury Internal Revenue Service

U.S. Corporation Income Tax Return

For calendar year 2019 or tax year beginning 10/01/2019, ending 09/30/2020

▶Go to www.irs.gov/Form1120 for instructions and the latest information.

OMB No. 1545-0123 **2019**

A Check if: 1a Consolidated return (attach Form 851) X; b Life/nonlife consolidated return; 2 Personal holding co. (attach Sch. PH); 3 Personal service corp. (see instructions); 4 Schedule M-3 attached X	TYPE OR PRINT — Name: UGI Corporation & Subsidiaries	B Employer identification number: 23-2668356
	Number, street, and room or suite no.: P.O. BOX 858	C Date incorporated: 12/01/1994
	City or town, state or province, country, and ZIP or foreign postal code: Valley Forge, PA 19482	D Total assets: $ 10,492,702,849.

E Check if: (1) Initial return (2) Final return (3) Name change (4) Address change

Income			
1a	Gross receipts or sales	1a 2,377,424,003.	
b	Returns and allowances	1b	
c	Balance. Subtract line 1b from line 1a	1c	2,377,424,003.
2	Cost of goods sold (attach Form 1125-A)	2	1,387,491,763.
3	Gross profit. Subtract line 2 from line 1c	3	989,932,240.
4	Dividends and inclusions (Schedule C, line 23)	4	125,681,534.
5	Interest	5	8,898,853.
6	Gross rents	6	
7	Gross royalties	7	
8	Capital gain net income (attach Schedule D (Form 1120))	8	NONE
9	Net gain or (loss) from Form 4797, Part II, line 17 (attach Form 4797)	9	-8,204,736.
10	Other income (see instructions - attach statement) See Statement 3	10	-13,202,382.
11	**Total income.** Add lines 3 through 10	11	1,103,105,509.
Deductions (See instructions for limitations on deductions.)			
12	Compensation of officers (see instructions - attach Form 1125-E)	12	21,596,233.
13	Salaries and wages (less employment credits)	13	139,968,764.
14	Repairs and maintenance See Statement 6	14	143,196,726.
15	Bad debts See Statement 9	15	6,785,057.
16	Rents See Statement 10	16	4,327,566.
17	Taxes and licenses See Statement 13	17	20,983,809.
18	Interest (see instructions) See Statement 19	18	151,529,993.
19	Charitable contributions See Statement 22	19	NONE
20	Depreciation from Form 4562 not claimed on Form 1125-A or elsewhere on return (attach Form 4562)	20	322,224,589.
21	Depletion	21	370,731.
22	Advertising See Statement 23	22	3,070,755.
23	Pension, profit-sharing, etc., plans	23	9,619,017.
24	Employee benefit programs	24	20,134,697.
25	Reserved for future use	25	
26	Other deductions (attach statement) See Statement 24	26	397,484,915.
27	**Total deductions.** Add lines 12 through 26	27	1,241,292,852.
28	Taxable income before net operating loss deduction and special deductions. Subtract line 27 from line 11	28	-138,187,343.
29a	Net operating loss deduction (see instructions)	29a	
b	Special deductions (Schedule C, line 24)	29b 116,827,705.	
c	Add lines 29a and 29b	29c	116,827,705.
Tax, Refundable Credits, and Payments			
30	**Taxable income.** Subtract line 29c from line 28. See instructions	30	-255,015,048.
31	Total tax (Schedule J, Part I, line 11)	31	NONE
32	2019 net 965 tax liability paid (Schedule J, Part II, line 12)	32	
33	Total payments, credits, and section 965 net tax liability (Schedule J, Part III, line 23)	33	3,910,964.
34	Estimated tax penalty. See instructions. Check if Form 2220 is attached ▶ ☐	34	
35	**Amount owed.** If line 33 is smaller than the total of lines 31, 32, and 34, enter amount owed	35	
36	**Overpayment.** If line 33 is larger than the total of lines 31, 32, and 34, enter amount overpaid	36	3,910,964.
37	Enter amount from line 36 you want: **Credited to 2020 estimated tax** ▶ 3,910,964. **Refunded** ▶	37	

Sign Here

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct, and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Signature of officer: MICHAEL R PEARSON | Date: 07/14/2021 | Title: VICE PRESIDENT CORP TAX ADMIN

May the IRS discuss this return with the preparer shown below? See instructions. ☐ Yes ☐ No

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no.	

For Paperwork Reduction Act Notice, see separate instructions. Form **1120** (2019)

UGI Corporation & Subsidiaries 23-2668356

Form 1120 (2019) Page 2

Schedule C Dividends, Inclusions, and Special Deductions (see instructions)	(a) Dividends and inclusions	(b) %	(c) Special deductions (a) x (b)
1 Dividends from less-than-20%-owned domestic corporations (other than debt-financed stock)		50	
2 Dividends from 20%-or-more-owned domestic corporations (other than debt-financed stock)		65	
3 Dividends on certain debt-financed stock of domestic and foreign corporations		see instructions	
4 Dividends on certain preferred stock of less-than-20%-owned public utilities		23.3	
5 Dividends on certain preferred stock of 20%-or-more-owned public utilities		26.7	
6 Dividends from less-than-20%-owned foreign corporations and certain FSCs		50	
7 Dividends from 20%-or-more-owned foreign corporations and certain FSCs		65	
8 Dividends from wholly owned foreign subsidiaries		100	
9 **Subtotal.** Add lines 1 through 8. See instructions for limitations		see instructions	
10 Dividends from domestic corporations received by a small business investment company operating under the Small Business Investment Act of 1958		100	
11 Dividends from affiliated group members	10,139.	100	10,139.
12 Dividends from certain FSCs		100	
13 Foreign-source portion of dividends received from a specified 10%-owned foreign corporation (excluding hybrid dividends) (see instructions)	116,817,566.	100	116,817,566.
14 Dividends from foreign corporations not included on line 3, 6, 7, 8, 11, 12, or 13 (including any hybrid dividends)			
15 Section 965(a) inclusion		see instructions	
16 a Subpart F inclusions derived from the sale by a controlled foreign corporation (CFC) of the stock of a lower-tier foreign corporation treated as a dividend (attach Form(s) 5471) (see instructions)		100	
b Subpart F inclusions derived from hybrid dividends of tiered corporations (attach Form(s) 5471) (see instructions)			
c Other inclusions from CFCs under subpart F not included on line 15, 16a, 16b, or 17 (attach Form(s) 5471) (see instructions)			
17 Global Intangible Low-Taxed Income (GILTI) (attach Form(s) 5471 and Form 8992)	7,579,096.		
18 Gross-up for foreign taxes deemed paid	1,274,733.		
19 IC-DISC and former DISC dividends not included on line 1, 2, or 3			
20 Other dividends			
21 Deduction for dividends paid on certain preferred stock of public utilities			
22 Section 250 deduction (attach Form 8993)			
23 **Total dividends and inclusions.** Add column (a), lines 9 through 20. Enter here and on page 1, line 4	125,681,534.		
24 **Total special deductions.** Add column (c), lines 9 through 22. Enter here and on page 1, line 29b			116,827,705.

Form **1120** (2019)

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Schedule J Tax Computation and Payment (see instructions)

Part I-Tax Computation

1	Check if the corporation is a member of a controlled group (attach Schedule O (Form 1120)). See instructions ▶ ☐				
2	Income tax. See instructions			2	
3	Base erosion minimum tax amount (attach Form 8991)			3	
4	Add lines 2 and 3			4	
5a	Foreign tax credit (attach Form 1118)	5a	NONE		
b	Credit from Form 8834 (see instructions)	5b			
c	General business credit (attach Form 3800)	5c			
d	Credit for prior year minimum tax (attach Form 8827)	5d			
e	Bond credits from Form 8912	5e			
6	**Total credits.** Add lines 5a through 5e			6	NONE
7	Subtract line 6 from line 4			7	NONE
8	Personal holding company tax (attach Schedule PH (Form 1120))			8	
9a	Recapture of investment credit (attach Form 4255)	9a			
b	Recapture of low-income housing credit (attach Form 8611)	9b			
c	Interest due under the look-back method - completed long-term contracts (attach Form 8697)	9c			
d	Interest due under the look-back method - income forecast method (attach Form 8866)	9d			
e	Alternative tax on qualifying shipping activities (attach Form 8902)	9e			
f	Other (see instructions - attach statement)	9f			
10	**Total.** Add lines 9a through 9f			10	
11	**Total tax.** Add lines 7, 8, and 10. Enter here and on page 1, line 31			11	NONE

Part II-Section 965 Payments (see instructions)

12	2019 net 965 tax liability paid from Form 965-B, Part II, column (k), line 3. Enter here and on page 1, line 32	12	

Part III-Payments, Refundable Credits, and Section 965 Net Tax Liability

13	2018 overpayment credited to 2019			13	3,903,645.
14	2019 estimated tax payments			14	
15	2019 refund applied for on Form 4466			15	( )
16	Combine lines 13, 14, and 15			16	3,903,645.
17	Tax deposited with Form 7004			17	
18	Withholding (see instructions)			18	
19	**Total payments.** Add lines 16, 17, and 18			19	3,903,645.
20	Refundable credits from:				
a	Form 2439	20a			
b	Form 4136	20b	7,319.		
c	Form 8827, line 5c	20c			
d	Other (attach statement - see instructions)	20d			
21	**Total credits.** Add lines 20a through 20d			21	7,319.
22	2019 net 965 tax liability from Form 965-B, Part I, column (d), line 3. See instructions			22	
23	**Total payments, credits, and section 965 net tax liability.** Add lines 19, 21, and 22. Enter here and on page 1, line 33			23	3,910,964.

Form **1120** (2019)

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Form 1120 (2019) Page 4

Schedule K Other Information (see instructions)

		Yes	No
1	Check accounting method: a [ ] Cash b [X] Accrual c [ ] Other (specify) ▶		
2	See the instructions and enter the:		
a	Business activity code no. ▶ 551112		
b	Business activity ▶ HOLDING COMPANY		
c	Product or service ▶ N/A		
3	Is the corporation a subsidiary in an affiliated group or a parent-subsidiary controlled group? If "Yes," enter name and EIN of the parent corporation ▶		X
4	At the end of the tax year:		
a	Did any foreign or domestic corporation, partnership (including any entity treated as a partnership), trust, or tax-exempt organization own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part I of Schedule G (Form 1120) (attach Schedule G)		X
b	Did any individual or estate own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of the corporation's stock entitled to vote? If "Yes," complete Part II of Schedule G (Form 1120) (attach Schedule G)		X
5	At the end of the tax year, did the corporation:		
a	Own directly 20% or more, or own, directly or indirectly, 50% or more of the total voting power of all classes of stock entitled to vote of any foreign or domestic corporation not included on **Form 851**, Affiliations Schedule? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Corporation	(ii) Employer Identification Number (if any)	(iii) Country of Incorporation	(iv) Percentage Owned in Voting Stock
See Statement 43			

		Yes	No
b	Own directly an interest of 20% or more, or own, directly or indirectly, an interest of 50% or more in any foreign or domestic partnership (including an entity treated as a partnership) or in the beneficial interest of a trust? For rules of constructive ownership, see instructions. If "Yes," complete (i) through (iv) below.	X	

(i) Name of Entity	(ii) Employer Identification Number (if any)	(iii) Country of Organization	(iv) Maximum Percentage Owned in Profit, Loss, or Capital
See Statement 45			

		Yes	No
6	During this tax year, did the corporation pay dividends (other than stock dividends and distributions in exchange for stock) in excess of the corporation's current and accumulated earnings and profits? See sections 301 and 316. If "Yes," file **Form 5452**, Corporate Report of Nondividend Distributions. See the instructions for Form 5452. If this is a consolidated return, answer here for the parent corporation and on Form 851 for each subsidiary.		X
7	At any time during the tax year, did one foreign person own, directly or indirectly, at least 25% of the total voting power of all classes of the corporation's stock entitled to vote or at least 25% of the total value of all classes of the corporation's stock? For rules of attribution, see section 318. If "Yes," enter: **(a)** Percentage owned ▶ ______ and **(b)** Owner's country ▶ ______ **(c)** The corporation may have to file **Form 5472,** Information Return of a 25% Foreign-Owned U.S. Corporation or a Foreign Corporation Engaged in a U.S. Trade or Business. Enter the number of Forms 5472 attached ▶		X
8	Check this box if the corporation issued publicly offered debt instruments with original issue discount ▶ [ ] If checked, the corporation may have to file **Form 8281,** Information Return for Publicly Offered Original Issue Discount Instruments.		
9	Enter the amount of tax-exempt interest received or accrued during the tax year ▶ $		
10	Enter the number of shareholders at the end of the tax year (if 100 or fewer) ▶		
11	If the corporation has an NOL for the tax year and is electing to forego the carryback period, check here (see instructions) ▶ [ ] If the corporation is filing a consolidated return, the statement required by Regulations section 1.1502-21(b)(3) must be attached or the election will not be valid.		
12	Enter the available NOL carryover from prior tax years (do not reduce it by any deduction reported on page 1, line 29a.) ▶ $		

UGI Corporation & Subsidiaries 23-2668356

Schedule K **Other Information** *(continued from page 4)*

		Yes	No
13	Are the corporation's total receipts (page 1, line 1a, plus lines 4 through 10) for the tax year **and** its total assets at the end of the tax year less than $250,000?		X
	If "Yes," the corporation is not required to complete Schedules L, M-1, and M-2. Instead, enter the total amount of cash distributions and the book value of property distributions (other than cash) made during the tax year ▶ $		
14	Is the corporation required to file Schedule UTP (Form 1120), Uncertain Tax Position Statement? See instructions	X	
	If "Yes," complete and attach Schedule UTP.		
15a	Did the corporation make any payments in 2019 that would require it to file Form(s) 1099?		X
b	If "Yes," did or will the corporation file required Form(s) 1099?		
16	During this tax year, did the corporation have an 80%-or-more change in ownership, including a change due to redemption of its own stock?		X
17	During or subsequent to this tax year, but before the filing of this return, did the corporation dispose of more than 65% (by value) of its assets in a taxable, non-taxable, or tax deferred transaction?		X
18	Did the corporation receive assets in a section 351 transfer in which any of the transferred assets had a fair market basis or fair market value of more than $1 million?		X
19	During the corporation's tax year, did the corporation make any payments that would require it to file Forms 1042 and 1042-S under chapter 3 (sections 1441 through 1464) or chapter 4 (sections 1471 through 1474) of the Code?		X
20	Is the corporation operating on a cooperative basis?		X
21	During the tax year, did the corporation pay or accrue any interest or royalty for which the deduction is not allowed under section 267A? See instructions		X
	If "Yes," enter the total amount of the disallowed deductions ▶ $		
22	Does the corporation have gross receipts of at least $500 million in any of the 3 preceding tax years? (See sections 59A(e)(2) and (3))	X	
	If "Yes," complete and attach Form 8991.		
23	Did the corporation have an election under section 163(j) for any real property trade or business or any farming business in effect during the tax year? See instructions		X
24	Does the corporation satisfy one or more of the following? See instructions	X	
a	The corporation owns a pass-through entity with current, or prior year carryover, excess business interest expense.		
b	The corporation's aggregate average annual gross receipts (determined under section 448(c)) for the 3 tax years preceding the current tax year are more than $26 million and the corporation has business interest expense.		
c	The corporation is a tax shelter and the corporation has business interest expense.		
	If "Yes," to any, complete and attach Form 8990.		
25	Is the corporation attaching Form 8996 to certify as a Qualified Opportunity Fund?		X
	If "Yes," enter amount from Form 8996, line 14 ▶ $		

UGI Corporation & Subsidiaries 23-2668356

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Schedule L Balance Sheets per Books

Assets	Beginning of tax year (a)	(b)	End of tax year (c)	(d)
1 Cash		305,774,908.		171,570,741.
2a Trade notes and accounts receivable	210,738,611.		222,666,141.	
b Less allowance for bad debts	(9,470,663.)	201,267,948.	(17,035,489.)	205,630,652.
3 Inventories		79,648,166.		76,059,876.
4 U.S. government obligations				
5 Tax-exempt securities (see instructions)				
6 Other current assets (attach statement)	Stmt 52	675,156,924.		-1,270,661.
7 Loans to shareholders				-81,255,196.
8 Mortgage and real estate loans				
9 Other investments (attach statement)	Stmt 60	7,795,717,410.		2,989,613,865.
10a Buildings and other depreciable assets	5,900,064,945.		6,223,636,064.	
b Less accumulated depreciation	(1,403,980,859.)	4,496,084,086.	(1,478,272,387.)	4,745,363,677.
11a Depletable assets				
b Less accumulated depletion	( )		( )	
12 Land (net of any amortization)		18,851,956.		21,675,042.
13a Intangible assets (amortizable only)	815,812,704.		836,633,936.	
b Less accumulated amortization	(20,130,109.)	795,682,595.	(34,393,377.)	802,240,559.
14 Other assets (attach statement)	Stmt 64	694,083,898.		1,563,074,294.
15 Total assets		15,062,267,891.		10,492,702,849.
Liabilities and Shareholders' Equity				
16 Accounts payable		178,898,840.		232,416,198.
17 Mortgages, notes, bonds payable in less than 1 year		481,378,465.		204,027,119.
18 Other current liabilities (attach statement)	Stmt 69	353,099,255.		158,176,427.
19 Loans from shareholders				
20 Mortgages, notes, bonds payable in 1 year or more		3,248,821,335.		-6,661,051.
21 Other liabilities (attach statement)	Stmt 78	1,375,731,502.		5,262,708,484.
22 Capital stock: a Preferred stock				
b Common stock	64,140,213.	64,140,213.	100.	100.
23 Additional paid-in capital		7,593,567,477.		1,928,555,773.
24 Retained earnings - Appropriated (attach statement)		2,191,068.		
25 Retained earnings - Unappropriated		2,017,154,023.		2,909,544,820.
26 Adjustments to shareholders' equity (attach statement)		-236,572,304.		-147,057,459.
27 Less cost of treasury stock		(16,141,983.)		(49,007,562.)
28 Total liabilities and shareholders' equity		15,062,267,891.		10,492,702,849.

Schedule M-1 Reconciliation of Income (Loss) per Books With Income per Return

Note: The corporation may be required to file Schedule M-3. See instructions.

1 Net income (loss) per books		7 Income recorded on books this year not included on this return (itemize): Tax-exempt interest $	
2 Federal income tax per books			
3 Excess of capital losses over capital gains			
4 Income subject to tax not recorded on books this year (itemize):		8 Deductions on this return not charged against book income this year (itemize):	
5 Expenses recorded on books this year not deducted on this return (itemize):		a Depreciation $	
a Depreciation $		b Charitable contributions $	
b Charitable contributions $			
c Travel and entertainment $			
		9 Add lines 7 and 8	
6 Add lines 1 through 5		10 Income (page 1, line 28) - line 6 less line 9	

Schedule M-2 Analysis of Unappropriated Retained Earnings per Books (Line 25, Schedule L)

1 Balance at beginning of year	2,576,499,093.	5 Distributions: a Cash	273,116,533.
2 Net income (loss) per books	507,869,484.	b Stock	
3 Other increases (itemize):		c Property	
		6 Other decreases (itemize) Stmt 88	7,177,423.
See Statement 84	105,470,199.	7 Add lines 5 and 6	280,293,956.
4 Add lines 1, 2, and 3	3,189,838,776.	8 Balance at end of year (line 4 less line 7)	2,909,544,820.

Form 1120 (2019)

SCHEDULE M-3 (Form 1120) (Rev. December 2019) Department of the Treasury Internal Revenue Service

Net Income (Loss) Reconciliation for Corporations With Total Assets of $10 Million or More

▶ Attach to Form 1120 or 1120-C.
▶ Go to *www.irs.gov/Form1120* for instructions and the latest information.

OMB No. 1545-0123

Name of corporation (common parent, if consolidated return): UGI Corporation
Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Non-consolidated return (2) [ ] Consolidated return (Form 1120 only)
(3) [X] Mixed 1120/L/PC group (4) [ ] Dormant subsidiaries schedule attached

Part I Financial Information and Net Income (Loss) Reconciliation (see instructions)

1 a Did the corporation file SEC Form 10-K for its income statement period ending with or within this tax year?
[X] **Yes.** Skip lines 1b and 1c and complete lines 2a through 11 with respect to that SEC Form 10-K.
[ ] **No.** Go to line 1b. See instructions if multiple non-tax-basis income statements are prepared.

b Did the corporation prepare a certified audited non-tax-basis income statement for that period?
[ ] **Yes.** Skip line 1c and complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Go to line 1c.

c Did the corporation prepare a non-tax-basis income statement for that period?
[ ] **Yes.** Complete lines 2a through 11 with respect to that income statement.
[ ] **No.** Skip lines 2a through 3c and enter the corporation's net income (loss) per its books and records on line 4a.

2 a Enter the income statement period: Beginning 10/01/2019 Ending 09/30/2020

b Has the corporation's income statement been restated for the income statement period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

c Has the corporation's income statement been restated for any of the five income statement periods immediately preceding the period on line 2a?
[ ] **Yes.** (If "Yes," attach an explanation and the amount of each item restated.)
[X] **No.**

3 a Is any of the corporation's voting common stock publicly traded?
[X] **Yes.**
[ ] **No.** If "No," go to line 4a.

b Enter the symbol of the corporation's primary U.S. publicly traded voting common stock: UGI

c Enter the nine-digit CUSIP number of the corporation's primary publicly traded voting common stock: 902681105

4 a	Worldwide consolidated net income (loss) from income statement source identified in Part I, line 1	4a	532,421,711.
b	Indicate accounting standard used for line 4a (see instructions): (1) [X] GAAP (2) [ ] IFRS (3) [ ] Statutory (4) [ ] Tax-basis (5) [ ] Other (specify)		
5 a	Net income from nonincludible foreign entities (attach statement) Stmt. 91.	5a	(38,024,265.)
b	Net loss from nonincludible foreign entities (attach statement and enter as a positive amount) Stmt. 91.	5b	14,158,719.
6 a	Net income from nonincludible U.S. entities (attach statement)	6a	( )
b	Net loss from nonincludible U.S. entities (attach statement and enter as a positive amount)	6b	
7 a	Net income (loss) of other includible foreign disregarded entities (attach statement)	7a	
b	Net income (loss) of other includible U.S. disregarded entities (attach statement) Stmt. 91.	7b	-676,543.
c	Net income (loss) of other includible entities (attach statement)	7c	
8	Adjustment to eliminations of transactions between includible entities and nonincludible entities (attach statement)	8	
9	Adjustment to reconcile income statement period to tax year (attach statement) Stmt. 92.	9	-10,138.
10 a	Intercompany dividend adjustments to reconcile to line 11 (attach statement)	10a	
b	Other statutory accounting adjustments to reconcile to line 11 (attach statement)	10b	
c	Other adjustments to reconcile to amount on line 11 (attach statement) Stmt. 93.	10c	
11	**Net income (loss) per income statement of includible corporations.** Combine lines 4 through 10	11	507,869,484.

Note: Part I, line 11, must equal Part II, line 30, column (a), or Schedule M-1, line 1 (see instructions).

12 Enter the total amount (not just the corporation's share) of the assets and liabilities of all entities included or removed on the following lines.

		Total Assets	Total Liabilities
a	Included on Part I, line 4 ▶	14,986,755,050.	10,266,122,910.
b	Removed on Part I, line 5 ▶		
c	Removed on Part I, line 6 ▶	1,683,118,235.	1,161,514,211.
d	Included on Part I, line 7 ▶		

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [X] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [ ] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): Nonlife Consolidation

Employer identification number:

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Gross-up for foreign taxes deemed paid				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation				
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)				
14 Total accrual to cash adjustment				
15 Hedging transactions				
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	( )			( )
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue				
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities				
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25				
27 **Total expense/deduction items** (from Part III, line 39)				
28 Other items with no differences				
29a Mixed groups, see instructions. All others, combine lines 26 through 28	507,745,202.	-765,787,447.	117,341,803.	-140,700,442.
b PC insurance subgroup reconciliation totals	124,282.	77,789.	130,796.	332,867.
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	507,869,484.	-765,709,658.	117,472,599.	-140,367,575.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Schedule M-3 (Form 1120) (Rev. 12-2019) Page **2**

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): 1120 Subgroup

Employer identification number

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 12)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions			7,579,096.	7,579,096.
4 Gross-up for foreign taxes deemed paid		1,274,733.		1,274,733.
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation	119,641,050.		-2,823,483.	116,817,567.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships	257,291,246.	-457,438,555.		-200,147,309.
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions				
13 Interest income (see instructions)	9,970,515.	-1,855,080.	718,200.	8,833,635.
14 Total accrual to cash adjustment				
15 Hedging transactions	-27,990,590.	-75,404,551.		-103,395,141.
16 Mark-to-market income (loss)				
17 Cost of goods sold (see instructions)	(1,403,145,229.)	29,599,333.		(1,373,545,896.)
18 Sale versus lease (for sellers and/or lessors)				
19 Section 481(a) adjustments				
20 Unearned/deferred revenue	-5,800,381.	5,415,203.		-385,178.
21 Income recognition from long-term contracts				
22 Original issue discount and other imputed interest				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than inventory and pass-through entities	-53,501,717.	1,536,473.	52,093,691.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-1,272,439.		-1,272,439.
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses		-11,767,967.		-11,767,967.
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets other than inventory			649,945.	649,945.
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)	7,472,740.	-17,226,932.	-3,722,665.	-13,476,857.
26 **Total income (loss) items.** Combine lines 1 through 25	-1,096,062,366.	-527,139,782.	54,494,784.	-1,568,707,364.
27 **Total expense/deduction items** (from Part III, line 39)	-507,328,013.	-238,647,665.	62,847,019.	-683,128,659.
28 Other items with no differences	2,111,135,581.			2,111,135,581.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	507,745,202.	-765,787,447.	117,341,803.	-140,700,442.
b PC insurance subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	507,745,202.	-765,787,447.	117,341,803.	-140,700,442.

Note: Line 30, column (a), must equal Part I, line 11, and column (d) must equal Form 1120, page 1, line 28.

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es): (1) [ ] Consolidated group (2) [ ] Parent corp (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120 group (7) [ ] 1120 eliminations

Name of subsidiary (if consolidated return): 1120 Subgroup

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	-85,189,525.		85,189,525.	
2 U.S. deferred income tax expense	137,171,082.		-137,171,082.	
3 State and local current income tax expense	2,889,178.	-120,025.		2,769,153.
4 State and local deferred income tax expense	15,973,516.	-10,115,981.	-5,857,535.	
5 Foreign current income tax expense (other than foreign withholding taxes)	-10,612,989.	10,612,989.		
6 Foreign deferred income tax expense	8,699,991.		-8,699,991.	
7 Foreign withholding taxes				
8 Interest expense (see instructions)	150,652,919.	877,074.		151,529,993.
9 Stock option expense	8,395,362.	-8,535,196.	2,370,639.	2,230,805.
10 Other equity-based compensation	3,280,261.	2,224,778.	4,509,728.	10,014,767.
11 Meals and entertainment	1,431,228.		-783,000.	648,228.
12 Fines and penalties	17,057.		-11,455.	5,602.
13 Judgments, damages, awards, and similar costs				
14 Parachute payments				
15 Compensation with section 162(m) limitation	3,071,462.		-1,362,724.	1,708,738.
16 Pension and profit-sharing	15,874,285.	-4,802,694.	-279,155.	10,792,436.
17 Other post-retirement benefits	-2,902,549.	1,729,130.		-1,173,419.
18 Deferred compensation				
19 Charitable contribution of cash and tangible property	853,307.		-31,750.	821,557.
20 Charitable contribution of intangible property				
21 Charitable contribution limitation/carryforward				
22 Domestic production activities deduction (see instructions)				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs		686,215.		686,215.
26 Amortization/impairment of goodwill		27,296,650.		27,296,650.
27 Amortization of acquisition, reorganization, and start-up costs		97,389.		97,389.
28 Other amortization or impairment write-offs	21,326,947.	8,264,515.	694,732.	30,286,194.
29 Reserved				
30 Depletion		370,731.		370,731.
31 Depreciation	171,716,706.	150,507,882.		322,224,588.
32 Bad debt expense	14,647,348.	-7,862,291.		6,785,057.
33 Corporate owned life insurance premiums				
34 Purchase versus lease (for purchasers and/or lessees)	4,054,230.	-1,070,746.		2,983,484.
35 Research and development costs				
36 Section 118 exclusion (attach statement)				
37 Section 162(r) - FDIC premiums paid by certain large financial institutions (see instructions)				
38 Other expense/deduction items with differences (attach statement)	45,978,197.	68,487,245.	-1,414,951.	113,050,491.
39 **Total expense/deduction items.** Combine lines 1 through 38. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	507,328,013.	238,647,665.	-62,847,019.	683,128,659.

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return): 1120-PC Subgroup

Employer identification number:

Part II Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return (see instructions)

Income (Loss) Items (Attach statements for lines 1 through 11)	(a) Income (Loss) per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Income (Loss) per Tax Return
1 Income (loss) from equity method foreign corporations				
2 Gross foreign dividends not previously taxed				
3 Subpart F, QEF, and similar income inclusions				
4 Gross-up for foreign taxes deemed paid				
5 Gross foreign distributions previously taxed				
6 Income (loss) from equity method U.S. corporations				
7 U.S. dividends not eliminated in tax consolidation	10,138.			10,138.
8 Minority interest for includible corporations				
9 Income (loss) from U.S. partnerships				
10 Income (loss) from foreign partnerships				
11 Income (loss) from other pass-through entities				
12 Items relating to reportable transactions (attach statement)				
13 Interest income (attach Form 8916-A)	30,027.			30,027.
14 Hedging transactions				
15 Mark-to-market income (loss)				
16 Premium income (attach statement)	246,538.	3,986.		250,524.
17 Sale versus lease (for sellers and/or lessors)				
18 Section 481(a) adjustments				
19 Reserved for future use				
20 Income recognition from long-term contracts				
21 Original issue discount and other imputed interest				
22 Reserved for future use				
23a Income statement gain/loss on sale, exchange, abandonment, worthlessness, or other disposition of assets other than pass-through entities	-71,232.		71,232.	
b Gross capital gains from Schedule D, excluding amounts from pass-through entities				
c Gross capital losses from Schedule D, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
d Net gain/loss reported on Form 4797, line 17, excluding amounts from pass-through entities, abandonment losses, and worthless stock losses				
e Abandonment losses				
f Worthless stock losses (attach statement)				
g Other gain/loss on disposition of assets				
24 Capital loss limitation and carryforward used				
25 Other income (loss) items with differences (attach statement)				
26 **Total income (loss) items.** Combine lines 1 through 25	215,471.	3,986.	71,232.	290,689.
27 **Total expense/deduction items** (from Part III, line 40)	-65,820.	73,803.	59,564.	67,547.
28 Other items with no differences	-25,369.			-25,369.
29a Mixed groups, see instructions. All others, combine lines 26 through 28	124,282.	77,789.	130,796.	332,867.
b 1120 subgroup reconciliation totals				
c Life insurance subgroup reconciliation totals				
30 **Reconciliation totals.** Combine lines 29a through 29c	124,282.	77,789.	130,796.	332,867.

Note: Line 30, column (a), must equal the amount on Part I, line 11, and column (d) must equal Form 1120-PC, Schedule A, line 35.

Name of corporation (common parent, if consolidated return): UGI Corporation

Employer identification number: 23-2668356

Check applicable box(es). (1) [ ] Consolidated group (2) [ ] Parent corp. (3) [ ] Consolidated eliminations (4) [ ] Subsidiary corp. (5) [X] Mixed 1120/L/PC group

Check if a sub-consolidated: (6) [X] 1120-PC group (7) [ ] 1120-PC eliminations

Name of subsidiary (if consolidated return): 1120-PC Subgroup

Employer identification number:

Part III Reconciliation of Net Income (Loss) per Income Statement of Includible Corporations With Taxable Income per Return - Expense/Deduction Items (see instructions)

Expense/Deduction Items	(a) Expense per Income Statement	(b) Temporary Difference	(c) Permanent Difference	(d) Deduction per Tax Return
1 U.S. current income tax expense	67,627.		-67,627.	
2 U.S. deferred income tax expense	-8,063.		8,063.	
3 State and local current income tax expense				
4 State and local deferred income tax expense				
5 Foreign current income tax expense (other than foreign withholding taxes)				
6 Foreign deferred income tax expense				
7 Foreign withholding taxes				
8 Stock option expense				
9 Other equity-based compensation				
10 Meals and entertainment				
11 Fines and penalties				
12 Judgments, damages, awards, and similar costs				
13 Parachute payments				
14 Compensation with section 162(m) limitation				
15 Pension and profit-sharing				
16 Other post-retirement benefits				
17 Deferred compensation				
18 Charitable contribution of cash and tangible property				
19 Charitable contribution of intangible property				
20 Charitable contribution limitation/carryforward				
21 Write-off of premium receivables				
22 Guarantee fund assessments				
23 Current year acquisition or reorganization investment banking fees				
24 Current year acquisition or reorganization legal and accounting fees				
25 Current year acquisition/reorganization other costs				
26 Amortization of acquisition, reorganization, and start-up costs				
27 Amortization/impairment of goodwill, insurance in force, and ceding commissions	21,964.	-21,964.		
28 Other amortization or impairment write-offs		-58,715.		-58,715.
29 Discounting of unpaid losses (section 846) (attach statement)	-11,800.	1,700.		-10,100.
30 Reduction of loss deduction (section 832(b)(5)(B))				
31 Depreciation				
32 Bad debt expense and/or agency balances written off				
33 Reserved for future use				
34 Corporate-owned life insurance premiums				
35 Purchase versus lease (for purchasers and/or lessees)				
36 Interest expense (attach Form 8916-A)				
37 Research and development costs				
38 Section 118 exclusion (attach statement)				
39 Other expense/deduction items with differences (attach statement)	-3,908.	5,176.		1,268.
40 **Total expense/deduction items.** Combine lines 1 through 39. Enter here and on Part II, line 27, reporting positive amounts as negative and negative amounts as positive	65,820.	-73,803.	-59,564.	-67,547.

UGI Corporation & Subsidiaries 23-2668356

Consolidated Schedules
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		Combined	UGI Eliminations Top Consolidation	Adjustments	UGI Corporation & Subsidiaries
1a	Gross receipts or sales	2,377,424,003.			2,377,424,003.
1b	Returns and allowances				
1c	Balance	2,377,424,003.			2,377,424,003.
2	Cost of goods sold	1,387,491,763.			1,387,491,763.
3	Gross profit	989,932,240.			989,932,240.
4	Dividends	125,681,534.			125,681,534.
5	Interest	8,898,853.			8,898,853.
6	Gross rents				
7	Gross royalties				
8	Capital gain net income	-1,272,439.		1,272,439.	NONE
9	Net gain or (loss) from Form 4797	-8,204,736.			-8,204,736.
10	Other income	-13,202,382.			-13,202,382.
11	Total income	1,101,833,070.		1,272,439.	1,103,105,509.
12	Compensation of officers	21,596,233.			21,596,233.
13	Salaries and wages	139,968,764.			139,968,764.
14	Repairs and maintenance	143,196,726.			143,196,726.
15	Bad debts	6,785,057.			6,785,057.
16	Rents	4,327,566.			4,327,566.
17	Taxes and licenses	20,983,809.			20,983,809.
18	Interest	151,529,993.			151,529,993.
19	Charitable contributions	907,790.		-907,790.	NONE
20	Depreciation	322,224,589.			322,224,589.
21	Depletion	370,735.		-4.	370,731.
22	Advertising	3,070,755.			3,070,755.
23	Pension, profit-sharing etc., plans	9,619,017.			9,619,017.
24	Employee benefit programs	20,134,697.			20,134,697.
25	Reserved for future use				
26	Other deductions	397,484,915.			397,484,915.
27	Total deductions	1,242,200,646.		-907,794.	1,241,292,852.
28	Taxable income before NOL & Spec. Deductions	-140,367,576.	NONE	2,180,233.	-138,187,343.
29	NOL,Spec. deductions	116,827,705.			116,827,705.
30	Taxable income	-257,195,281.	NONE	2,180,233.	-255,015,048.

Consolidated Schedules

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		1120C Subgroup	1120 PC Subgroup
		23-2668356	03-0338831
1a	Gross receipts or sales	2,377,173,479.	250,524.
1b	Returns and allowances		
1c	Balance	2,377,173,479.	250,524.
2	Cost of goods sold	1,387,491,763.	
3	Gross profit	989,681,716.	250,524.
4	Dividends	125,671,396.	10,138.
5	Interest	8,868,826.	30,027.
6	Gross rents		
7	Gross royalties		
8	Capital gain net income	-1,272,439.	
9	Net gain or (loss) from Form 4797	-8,204,736.	NONE
10	Other income	-13,202,382.	
11	Total income	1,101,542,381.	290,689.
12	Compensation of officers	21,596,233.	
13	Salaries and wages	139,968,764.	
14	Repairs and maintenance	143,196,726.	
15	Bad debts	6,785,057.	
16	Rents	4,327,566.	
17	Taxes and licenses	21,045,684.	-61,875.
18	Interest	151,529,993.	
19	Charitable contributions	907,790.	
20	Depreciation	322,224,589.	
21	Depletion	370,735.	
22	Advertising	3,070,755.	
23	Pension, profit-sharing etc., plans	9,619,017.	
24	Employee benefit programs	20,134,697.	
25	Reserved for future use		
26	Other deductions	397,465,218.	19,697.
27	Total deductions	1,242,242,824.	-42,178.
28	Taxable income before NOL & Spec. Deductions	-140,700,443.	332,867.
29	NOL,Spec. deductions	116,817,567.	10,138.
30	Taxable income	-257,518,010.	322,729.

1120C Subgroup 23-2668356

Consolidated Schedules
1120 Page 1

		Combined	UGI Eliminations	Adjustments	1120C Subgroup
1a	Gross receipts or sales	2,631,902,766.	-254,729,287.		2,377,173,479.
1b	Returns and allowances				
1c	Balance	2,631,902,766.	-254,729,287.		2,377,173,479.
2	Cost of goods sold	1,625,799,550.	-238,307,787.		1,387,491,763.
3	Gross profit	1,006,103,216.	-16,421,500.		989,681,716.
4	Dividends	318,145,402.	-192,474,006.		125,671,396.
5	Interest	8,521,225.	347,601.		8,868,826.
6	Gross rents				
7	Gross royalties				
8	Capital gain net income	2,290,792.		-3,563,231.	-1,272,439.
9	Net gain or (loss) from Form 4797	-11,767,967.		3,563,231.	-8,204,736.
10	Other income	-13,070,316.	-132,066.		-13,202,382.
11	Total income	1,310,222,352.	-208,679,971.		1,101,542,381.
12	Compensation of officers	21,596,233.			21,596,233.
13	Salaries and wages	140,100,829.	-132,065.		139,968,764.
14	Repairs and maintenance	143,196,726.			143,196,726.
15	Bad debts	6,785,057.			6,785,057.
16	Rents	4,327,566.			4,327,566.
17	Taxes and licenses	21,045,684.			21,045,684.
18	Interest	151,182,392.	347,601.		151,529,993.
19	Charitable contributions	907,790.			907,790.
20	Depreciation	322,224,589.			322,224,589.
21	Depletion	370,735.			370,735.
22	Advertising	3,070,755.			3,070,755.
23	Pension, profit-sharing etc., plans	9,619,017.			9,619,017.
24	Employee benefit programs	20,134,697.			20,134,697.
25	Reserved for future use				
26	Other deductions	413,886,719.	-16,421,501.		397,465,218.
27	Total deductions	1,258,448,789.	-16,205,965.		1,242,242,824.
28	Taxable income before NOL & Spec. Deductions	51,773,563.	-192,474,006.		-140,700,443.
29	NOL,Spec. deductions	309,291,573.	-192,474,006.		116,817,567.
30	Taxable income	-257,518,010.			-257,518,010.

1120C Subgroup 23-2668356

Consolidated Schedules
1120 Page 1

	UGI Corporation 23-2668356	AmeriGas Propane, Inc. 23-2786294	AmeriGas Technology Group, Inc. 23-2861011	AmeriGas, Inc. 23-2716858	Ashtola Production Company 23-2101362	Eastfield International Holdings, Inc. 51-0385770	Energy Services Funding Corporation 23-3099149	EuroGas Holdings, Inc. 51-0392140
1a Gross receipts or sales	1,138,913,328.							
1b Returns and allowances								
1c Balance	1,138,913,328.							
2 Cost of goods sold	823,279,961.							
3 Gross profit	315,633,367.							
4 Dividends	135,659,456.			56,814,551.				
5 Interest	602,399.							
6 Gross rents								
7 Gross royalties								
8 Capital gain net income		2,264,232.						
9 Net gain or (loss) from Form 4797	-12,336.							
10 Other income	-69,610,366.	65,134,161.			9.		5,258,588.	
11 Total income	382,272,520.	67,398,393.		56,814,551.	9.		5,258,588.	
12 Compensation of officers	17,399,158.	708,738.						
13 Salaries and wages	46,960,904.	473,353.						
14 Repairs and maintenance	25,505,513.							
15 Bad debts							529,105.	
16 Rents	2,635,890.							
17 Taxes and licenses	8,124,989.	10,422,282.		14,099.			386,167.	
18 Interest	97,071,512.						603,737.	
19 Charitable contributions	618,857.	43,793.						
20 Depreciation	174,609,004.	5,447.		4,038.				
21 Depletion	370,735.							
22 Advertising	994,762.							
23 Pension, profit-sharing etc., plans	2,037,584.							
24 Employee benefit programs	5,725,560.							
25 Reserved for future use								
26 Other deductions	65,878,483.	-575,485.		4,387.	1,161.		260,117.	
27 Total deductions	447,932,951.	11,078,128.		22,524.	1,161.		1,779,126.	
28 Taxable income before NOL & Spec. Deductions	-65,660,431.	56,320,265.	NONE	56,792,027.	-1,152.	NONE	3,479,462.	NONE
29 NOL,Spec. deductions	135,659,456.			56,814,551.				
30 Taxable income	-201,319,887.	56,320,265.	NONE	-22,524.	-1,152.	NONE	3,479,462.	NONE

1120C Subgroup 23-2668356

Consolidated Schedules
1120 Page 1

		Four Flags Drilling Company	Hellertown Pipeline Company	Homestead Holding Company	Newbury Holding Company	UGI Asset Management, Inc.	UGI Black Sea Enterprises, Inc.	UGI China, Inc.	UGI Development Company
		23-2178262	46-0490470	51-0467618	30-0170818	51-0380873	23-2800542	52-2095053	23-1650159
1a	Gross receipts or sales								36,194,223.
1b	Returns and allowances								
1c	Balance								36,194,223.
2	Cost of goods sold								15,873,430.
3	Gross profit								20,320,793.
4	Dividends								
5	Interest			-598,767.	963,925.				26,386.
6	Gross rents								
7	Gross royalties								
8	Capital gain net income								-1,272,439.
9	Net gain or (loss) from Form 4797								-10,624,816.
10	Other income								-201,347.
11	Total income			-598,767.	963,925.				8,248,577.
12	Compensation of officers								
13	Salaries and wages								1,879,168.
14	Repairs and maintenance								3,679,067.
15	Bad debts								
16	Rents			2,281.	2,143.				478,830.
17	Taxes and licenses				311.				197,895.
18	Interest								103.
19	Charitable contributions								
20	Depreciation								9,991,074.
21	Depletion								
22	Advertising								
23	Pension, profit-sharing etc., plans								111,514.
24	Employee benefit programs								243,298.
25	Reserved for future use								
26	Other deductions			6,222.	6,008.				8,525,714.
27	Total deductions			8,503.	8,462.				25,106,663.
28	Taxable income before NOL & Spec. Deductions	NONE	NONE	-607,270.	955,463.	NONE	NONE	NONE	-16,858,086.
29	NOL,Spec. deductions								
30	Taxable income	NONE	NONE	-607,270.	955,463.	NONE	NONE	NONE	-16,858,086.

1120C Subgroup 23-2668356

Consolidated Schedules 1120 Page 1	UGI Energy Ventures, Inc 71-0992456	UGI Ethanol Development Company 23-2179048	UGI Europe, Inc. 23-3070112	UGI Hunlock Development Company 23-3051491	UGI HVAC Enterprises, Inc. 51-0375688	UGI International (China), Inc. 23-2867252	UGI International (Romania), Inc. 23-2837401	UGI LNG, Inc 51-0590685
1a Gross receipts or sales			362,747,044.		40,609,026.			13,269,824.
1b Returns and allowances								
1c Balance			362,747,044.		40,609,026.			13,269,824.
2 Cost of goods sold			347,273,504.		19,963,746.			
3 Gross profit			15,473,540.		20,645,280.			13,269,824.
4 Dividends			125,671,395.					
5 Interest			7,498,821.		5,808.			4,398.
6 Gross rents								
7 Gross royalties								
8 Capital gain net income								
9 Net gain or (loss) from Form 4797					-1,127,238.			
10 Other income			-918,763.		-79,895.			
11 Total income			147,724,993.		19,443,955.			13,274,222.
12 Compensation of officers					504,718.			
13 Salaries and wages			2,055,655.		8,839,555.			
14 Repairs and maintenance								1,073,204.
15 Bad debts					251,937.			
16 Rents			4,326.		591,756.			
17 Taxes and licenses			-1,649,947.		903,510.			463,897.
18 Interest			1,232,934.		78,968.			
19 Charitable contributions					200.			
20 Depreciation			420.		946,877.			7,356,862.
21 Depletion								
22 Advertising			1,490,389.		1,559,617.			
23 Pension, profit-sharing etc., plans					638,638.			
24 Employee benefit programs					1,798,918.			
25 Reserved for future use								
26 Other deductions			4,978,862.		-1,494,553.			2,062,137.
27 Total deductions			8,112,639.		14,620,141.			10,956,100.
28 Taxable income before NOL & Spec. Deductions	NONE	NONE	139,612,354.	NONE	4,823,814.	NONE	NONE	2,318,122.
29 NOL,Spec. deductions			116,817,566.					
30 Taxable income	NONE	NONE	22,794,788.	NONE	4,823,814.	NONE	NONE	2,318,122.

1120C Subgroup

23-2668356

Consolidated Schedules
1120 Page 1

		UGI Penn HVAC Services, Inc	UGI Petroleum Products of Delaware, Inc	UGI Properties, Inc.	UGI Romania, Inc.	UGI Storage Company	UGID Holding Company	UGI Utilities, Inc	AmeriGas Propane Holdings, Inc
		23-1946160	51-0056772	23-2710207	23-2925615	32-0309503	51-0389590	23-1174060	83-4160550
1a	Gross receipts or sales			2,369,875.		8,796,515.		1,029,002,931.	
1b	Returns and allowances								
1c	Balance			2,369,875.		8,796,515.		1,029,002,931.	
2	Cost of goods sold					43,169.		419,365,740.	
3	Gross profit			2,369,875.		8,753,346.		609,637,191.	
4	Dividends								
5	Interest					5,173.		13,082.	
6	Gross rents								
7	Gross royalties								
8	Capital gain net income								1,298,999.
9	Net gain or (loss) from Form 4797							-3,577.	
10	Other income			5,626.		2,580.		-4,933,813.	-7,727,096.
11	Total income			2,375,501.		8,761,099.		604,712,883.	-6,428,097.
12	Compensation of officers							2,983,619.	
13	Salaries and wages							79,892,194.	
14	Repairs and maintenance			262,292.		551,731.		112,124,919.	
15	Bad debts							6,004,015.	
16	Rents						2,143.	610,197.	
17	Taxes and licenses			257,289.		9,947.		12,227,250.	-10,312,005.
18	Interest			657,221.				51,537,917.	
19	Charitable contributions			2,500.		200,000.			42,440.
20	Depreciation			507,728.		1,532,024.		127,271,115.	
21	Depletion								
22	Advertising							-974,013.	
23	Pension, profit-sharing etc., plans							6,831,281.	
24	Employee benefit programs							12,366,921.	
25	Reserved for future use								
26	Other deductions			339,472.		2,315,576.	5,842.	120,561,100.	211,011,676.
27	Total deductions			2,026,502.		4,609,278.	7,985.	531,436,515.	200,742,111.
28	Taxable income before NOL & Spec. Deductions	NONE	NONE	348,999.	NONE	4,151,821.	-7,985.	73,276,368.	-207,170,208.
29	NOL,Spec. deductions								
30	Taxable income	NONE	NONE	348,999.	NONE	4,151,821.	-7,985.	73,276,368.	-207,170,208.

BOOK III

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 1 – CHRISTOPHER R. BROWN
UGI GAS STATEMENT NO. 2 – TRACY A. HAZENSTAB
UGI GAS STATEMENT NO. 3 – VIVIAN K. RESSLER
UGI GAS STATEMENT NO. 4 – JOHN F. WIEDMAYER
UGI GAS STATEMENT NO. 5 – VICKY A. SCHAPPELL

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 **Effective: March 29, 2022**

UGI GAS STATEMENT NO. 1

CHRISTOPHER R. BROWN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 1

Direct Testimony of
Christopher R. Brown

Topics Addressed:	**Purpose of Testimony and Rate Filing Overview** **Need for Rate Relief** **COVID-19 Relief Efforts** **Unification of Rates** **UGI-1 Initiative and UNITE** **Auburn Capacity Lease** **Salaries and Wages Adjustments** **Management Performance**

Dated: January 28, 2022

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Christopher R. Brown. My business address is 1 UGI Drive, Denver, PA 17517.

Q. By whom and in what capacity are you employed?

A. I am employed by UGI Utilities, Inc. ("UGI") as its Vice President and General Manager of Rates and Supply. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Gas Division ("UGI Gas" or the "Company") and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please briefly describe your responsibilities in that capacity.

A. As Vice President and General Manager of Rates and Supply, I am responsible for all rate, supply, and associated regulatory compliance activities for UGI Gas and UGI Electric. For the rates component, I oversee the areas of sales and revenue forecasting, tariff administration and compliance, Choice administration and compliance, rate application, Section 1307(f) purchased gas cost ("PGC") filings, electric provider of last resort ("POLR") filings, Section 1307(e) filings, base rate cases, and UGI's energy management information technology systems. My supply responsibilities include oversight of supply procurement and contracting, gas and power scheduling, and tracking of interstate pipeline and wholesale power market activities that affect the Company's gas and power procurement costs. My regulatory compliance responsibilities cover a broad range of oversight and compliance for the state and federal jurisdictional activities of UGI. Prior to my role as Vice President and General Manager of Rates and Supply, I was Senior Director of Operations for UGI's southern operating region. In my current role, I report directly to the Chief Regulatory Officer.

Q. What is your educational and professional background?

A. Please see my resume, UGI Gas Exhibit CRB-1, which is attached to my testimony.

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit CRB-1 contains a list of those proceedings.

II. PURPOSE OF TESTIMONY AND RATE FILING OVERVIEW

Q. Please describe the purpose of your testimony in this proceeding.

A. My testimony addresses several points. First, I present an overview of the rate filing, including a brief explanation of the reasons for rate relief and an outline of the testimony of each witness in this proceeding, including the Company's proposal to implement alternative ratemaking, specifically a Weather Normalization Adjustment. Second, I discuss the Company's efforts to provide relief to customers impacted by the COVID-19 Pandemic, as well as related operational impacts. Third, I explain the Company's proposal to complete the final step in the rate unification of the former North and South/Central Rate Districts (*i.e.*, Rates N/NT and DS). Fourth, I summarize the recent successes accomplished through the UGI-1 and the UGI Next Information Technology Enterprise ("UNITE") initiatives. Fifth, I describe adjustments made to salaries and wages which are additions to the original future test year ("FTY") and fully projected test year ("FPFTY") budgets. Lastly, I summarize the evidence of UGI Gas's successful management performance and propose how it should be recognized in this case.

Q. Are you sponsoring any exhibits in this proceeding?

A. I am sponsoring UGI Gas Exhibit CRB-1. Also, I am sponsoring certain responses to the Commission's standard filing requirements, as indicated on the master list accompanying this filing.

Q. Please identify the other witnesses providing direct testimony on behalf of UGI Gas in this proceeding and the subject matter of their testimony.

A. In addition to my testimony, the following witnesses are providing testimony in support of the Company's rate request:

Tracy A. Hazenstab (UGI Gas Statement No. 2) holds the position of Principal Analyst - Rates for UGI Gas. She addresses UGI Gas's budgeting process; operating revenues and expenses; compliance with Section 1301.1 of the Public Utility Code; and the revenue requirement model supporting the Company's proposed rate increase (UGI Gas Exhibit A (Fully Projected)). Ms. Hazenstab also sponsors the revenue requirement models for the future and historic periods, UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic), respectively.

Vivian K. Ressler (UGI Gas Statement No. 3) holds the position of Senior Manager, Plant and Regulatory Accounting at UGI. Ms. Ressler presents UGI Gas's rate base claim for the Historic Test Year ("HTY"), FTY, and FPFTY. Ms. Ressler also addresses accounting for information technology costs and budget adjustments.

John F. Wiedmayer (UGI Gas Statement No. 4) holds the position of Project Manager at Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Wiedmayer developed and supports UGI Gas's claim for annual depreciation expense, and the accumulated depreciation reserve. His studies are presented in UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Historic).

Vicky A. Schappell (UGI Gas Statement No. 5) holds the position of Principal Analyst, Capital Planning for UGI Gas. Ms. Schappell addresses capital expenditures and capital planning, including those for UNITE Phase III - Enterprise Asset Management ("EAM").

Paul R. Moul (UGI Gas Statement No. 6) holds the role of Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents expert testimony supporting the Company's claimed capital structure, cost of debt, cost of common equity, and overall fair rate of return. Schedules and workpapers supporting Mr. Moul's findings are set forth in UGI Gas Exhibit B (Rate of Return).

Nicole M. McKinney (UGI Gas Statement No. 7) holds the position of Director of Financial Planning and Analysis for UGI Corporation. Ms. McKinney addresses various tax issues, including the Company's claim for federal and state income taxes, taxes other than income taxes, the calculation of the accumulated deferred income taxes ("ADIT") offset to rate base, the repairs allowance and the calculation of a hypothetical consolidated tax savings adjustment as required by Section 1301.1 of the Public Utility Code.

Sherry A. Epler (UGI Gas Statement No. 8) holds the position of Senior Manager Tariff and Supplier Administration – Rates for UGI Gas. Ms. Epler's testimony addresses the development of the Company's HTY, FTY and FPFTY test year sales and revenues. In addition, Ms. Epler addresses proposed revenue allocation, rate design and tariff updates. Ms. Epler sponsors UGI Gas Exhibit E (Proof of Revenue) and UGI Gas Exhibit F (Current and Proposed Tariffs).

Timothy J. Angstadt (UGI Gas Statement No. 9) holds the position of Vice President of Operations. Mr. Angstadt's testimony addresses UGI Gas's operations and natural gas system, and the impacts COVID-19 had on the Company's field operations. In addition, Mr. Angstadt discusses UGI Gas's Commission-approved Long-Term Infrastructure Improvement Plan ("LTIIP"), and the impact of the LTIIP and other initiatives on system performance, safety, and reliability. Mr. Angstadt further discusses certain proposed employee additions that are necessary for UGI Gas to maintain the pace of its capital replacement program. In addition, Mr. Angstadt addresses UGI Gas's efforts and future plans to investigate and, where necessary, remediate sites in Pennsylvania where UGI Gas or corporate predecessors once owned and/or operated manufactured gas plants in connection with gas utility operations.

Constance E. Heppenstall (UGI Gas Statement No. 10) holds the role of Senior Project Manager – Rate Studies for Gannett Fleming Valuation & Rate Consultants, LLC. Ms.

Heppenstall prepared and sponsors UGI Gas's fully allocated cost of service study. This study is contained in UGI Gas Exhibit D. The Allocated Cost of Service Study ("ACOSS") allocates the Company's cost of service associated with Commission jurisdictional operations to the Company's retail customer classes.

John D. Taylor (UGI Electric Statement No. 11) is a Managing Partner of Atrium Economics LLC. Mr. Taylor's testimony addresses the rationale, design and applicability of the Company's proposed Weather Normalization Adjustment mechanism.

III. NEED FOR RATE RELIEF

Q. Please discuss UGI Gas's proposed rate relief request and provide an overview of the Company's proposals in this proceeding.

A. UGI Gas is requesting an increase in its annual base rate operating revenues of $82.7 million, or 7.8 percent on a total revenue basis, with a proposed effective date of March 29, 2022. The base rate increase requested in this filing utilizes a FPFTY ending September 30, 2023. In addition, UGI Gas proposes in this proceeding to complete the transition to uniform distribution rates for both Rates N/NT and Rate DS across the former North and South/Central Rate Districts, an effort proposed but not completed as part of the Company's 2019 and 2020 rate cases.

Q. Has the Company evaluated the impact of its proposed rate increase on average customer bills generally?

A. Yes. As shown in Table 1, below, the Company has evaluated the impact of its proposed rate increase on the average monthly bill of residential heating, commercial heating, and industrial customers.

Table 1 Average Monthly Bill Impact

Average Residential Heating Customer Bill Impact

		Total Monthly Bill Impact			
	Average Usage	Current	Proposed	Increase (Decrease)	Total
All Customers	73.1 Ccf	$ 98.62	$ 108.01	$ 9.39	9.5%

Average Commercial Heating Customer Bill Impact

		Total Monthly Bill Impact			
	Average Usage	Current	Proposed	Increase (Decrease)	Total
Former North	28.8 Mcf	$ 307.00	$ 330.09	$ 23.09	7.5%
All Others	28.8 Mcf	$ 317.93	$ 330.09	$ 12.16	3.8%

Average Industrial Customer Bill Impact

		Total Monthly Bill Impact			
	Average Usage	Current	Proposed	Increase (Decrease)	Total
Former North	92.4 Mcf	$ 931.45	$ 993.83	$ 62.38	6.7%
All Others	92.4 Mcf	$ 966.55	$ 993.83	$ 27.28	2.8%

The average customer monthly bill impacts set forth in Table 1, above, are fair and reasonable because, as described in more detail below, UGI Gas will utilize the increase in distribution rates to support its ongoing provision of safe and reliable distribution service for its customers and, even with this increase, will continue to have distribution rates that compare favorably to other Pennsylvania natural gas distribution companies (“NGDC”), and on a total bill basis, inclusive of natural gas costs. Moreover, the Company’s average customer bills are less than they were in 2008. The proposed customer charges also reasonably reflect cost-of-service principles, while considering the rate design principles of gradualism.

Q. Why is UGI Gas seeking a rate increase at this time?

A. UGI Gas continues to make substantial distribution system investments that are necessary to: continue the accelerated replacement of aging gas plant infrastructure; upgrade and improve system segments and modernize facilities; serve new residential and commercial customers; connect customers converting to natural gas; install and upgrade supporting information technology systems; and ensure the safety of the Company's employees, the communities it serves, and its distribution system. Moving forward, these system improvements and investments will require the Company to increase its efforts to attract, recruit, train, and retain those professional, technical, and field-qualified personnel and resources necessary to implement, operate, and maintain those investments. These investments are all necessary to grow and continue to maintain a safe and reliable distribution system and provide quality customer service. As compared to pre-FPFTY gross plant levels, UGI Gas is projecting an increase of approximately $445 million in gross plant through the FPFTY compared to the end of the FTY and $795 million in gross plant when compared to the end of the HTY. Based on this factor alone, UGI Gas's current rates will not provide it with a reasonable opportunity to earn its cost of capital on its increased rate base investments.

Other cost drivers adversely impact the Company's ability to earn a reasonable rate of return on its utility investments. Since its last base rate case in 2020, UGI Gas has adopted reasonable and competitive annual wage and salary adjustments, meeting industry benchmarks for wages and salaries in order to retain and attract qualified employees. UGI

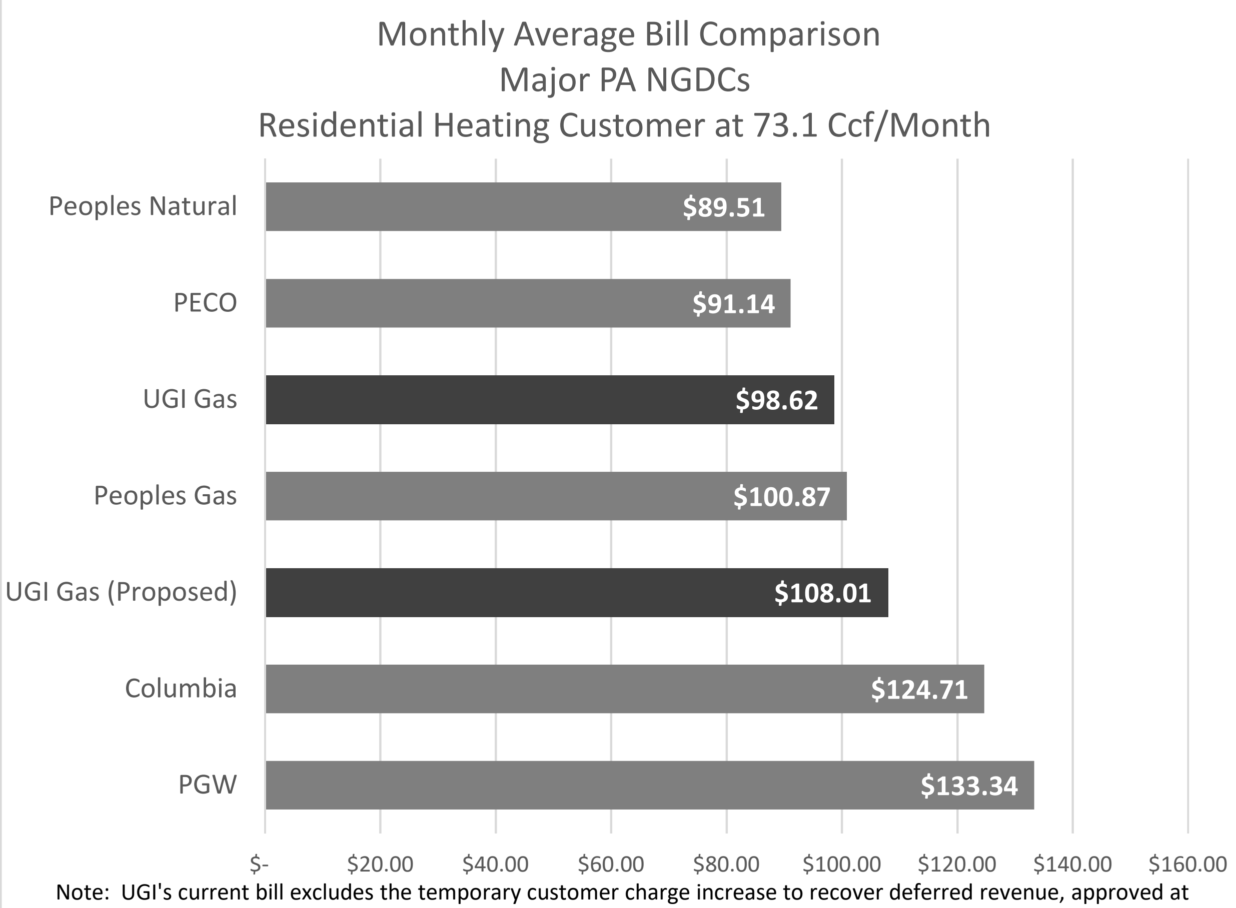
Gas will continue to do so where necessary to maintain a productive and effective workforce. The Company has also experienced other general price increases for necessary products and services. The Company is specifically planning for needed increases to staffing levels to maintain reliability, regulatory compliance, and continued improvement in several areas, most notably, information technology, operations, and training. While UGI Gas continues to focus on efficient operations and has seen stable customer growth over time, the Company's forecasted increases in operating and capital costs, along with experienced and anticipated changes in per customer usage, will prevent UGI Gas from having a reasonable opportunity to earn a fair rate of return on its investment at present rates.

Specifically, as reflected in UGI Gas Exhibit A (Fully Projected), Schedule A-1, UGI Gas's operations are projected to produce an overall return on rate base of 6.13%, which equates to a return on common equity of only 7.89% for the twelve months ending September 30, 2023. As explained by UGI Gas witness Paul R. Moul (UGI Gas Statement No. 6), those returns are not adequate based on applicable financial analysis and the risks confronted by UGI Gas. Unless UGI Gas receives the requested rate relief, those returns will continue to decline and potentially jeopardize UGI Gas's ability to attract the capital needed to make system investments that support enhancing the reach and capacity of its distribution system. Moreover, with its requested rate relief, UGI Gas will have sufficient return on investment needed to continue replacing older, more risk prone facilities, systems, and equipment, each of which is necessary to ensure continued system reliability, safety, and customer service performance. UGI Gas anticipates that it will be filing another rate case approximately a year following the filing of this base rate proceeding, as significant capital investment amounts similar to those projected for the FPFTY are projected to continue and will drive the need for additional timely rate relief.

Q. How do UGI Gas's rates compare with other Pennsylvania utilities?

A. A comparison of average residential heating bills, shown in Table 2 below, illustrates that UGI Gas's current distribution rates compare favorably to the rates of other major NGDCs in the Commonwealth, and will remain so, even at the full increase of proposed rates.

<u>Table 2 – Residential Heating Distribution Rate Comparison</u>



Note: UGI's current bill excludes the temporary customer charge increase to recover deferred revenue, approved at Docket No. R-2019-3015162 and is set to expire on September 30, 2022.

In considering UGI Gas's overall rates, it is also important to note that the Company has focused in recent years on a continued restructuring of its natural gas supply portfolio in order to maximize the benefits associated with the Commonwealth's shale gas supply resources. Also the Company has increased its focus on Environmental, Social and Governance ("ESG") activities, such as the Company's recently approved, first of its kind, pilot program designed to demonstrate the benefits of utilizing renewable natural gas ("RNG") as part of the Company's supply portfolio. RNG stands to provide numerous benefits to the natural gas industry and its consumers as related to the provision of lower-carbon solutions that can be readily integrated into existing natural gas systems. Despite recent increases in the cost of gas, customer benefits associated with these activities are readily evident. Even with the rate changes proposed in this proceeding, the average residential heating customer bill will be 21% lower than it was in 2008 when natural gas commodity prices were materially higher. In summary, UGI Gas offers excellent service to customers at reasonable rates.

IV. COVID-19 RELIEF EFFORTS

Q. Please describe how the COVID-19 pandemic has affected UGI Gas's provision of service to its customers.

A. Since March 6, 2020, when Pennsylvania Governor Wolf issued a Proclamation of Disaster Emergency,[1] followed by a March 15, 2020 Executive Order implementing widespread closures of non-life-sustaining businesses and work from home directives, UGI Gas has had to adapt its operations, accounting, and customer outreach to respond to the enduring COVID-19 Pandemic. In the intervening months, the Governor's office issued a number of subsequent orders - including, the Limited Time Mitigation Order issued December 10, 2020, which limited or suspended many indoor operations and gatherings.[2] In addition to the orders issued by the Governor's office, the Commission issued Emergency Orders on

[1] https://www.pema.pa.gov/Governor-Proclamations/Pages/default.aspx
[2] https://www.governor.pa.gov/wp-content/uploads/2020/12/20201210-TWW-Limited-Time-Mitigation-Order.pdf

March 13, 2020, March 20, 2020, and October 13, 2020, modifying the Commission's policies and procedures in response to COVID-19.

Q. How did these orders from the Governor and the Commission affect Company operations?

A. The operational impact of the COVID-19 Pandemic ("Pandemic") is discussed in more detail by UGI Gas witness Mr. Angstadt (UGI Gas Statement No. 9). However, in response to the Pandemic, the Company transitioned as much of its workforce to remote duties as possible. The Company adopted numerous practices to ensure the safety of its employees and customers. This permitted the Company to maintain the ongoing safe and reliable operation of the distribution system.

Q. Did the Company assist customers impacted by the economic effects of the Pandemic?

A. Yes. Consistent with the Commission's March 13, 2020 Emergency Order, the Company ceased service terminations and took measures to protect low-income customers affected by the Pandemic. Beginning March 18, 2020, the Company ceased removing customers from its Customer Assistance Plan ("CAP") for failure to recertify and instructed Community Based Organizations ("CBOs") to accept telephonic "signatures" for CAP program authorizations. On March 24, 2020, the Company began waiving all late payment charges. The Company subsequently resumed normal low-income activities in July 2021.

On May 21, 2020, UGI Utilities, Inc. filed a petition to modify its consolidated Universal Service and Energy Conservation Plan ("USECP") to implement a pre-pandemic proposal to reduce maximum-tiered monthly Percent-of-Income payments ("PIPs") required of its CAP customers.[3] In this PIP petition, the Company sought to update the USECP to reflect the Commission's revisions to the CAP Policy Statement at 52 Pa. Code § 69.261 et seq. On August 5, 2021, the Commission entered an Order seeking supplemental information (regarding program costs and CAP participation levels) and establishing comment and reply comment periods. While the Commission has not ruled on the petition, the Company believes energy burdens on UGI Gas's CAP customers will be reduced if the petition is approved.

The Company also made changes to its Low-Income Usage Reduction Program ("LIURP") to provide additional funding to LIURP contractors of up to $500 per LIURP job. These funds address Pandemic related costs (i.e., personal protective equipment, masks, hand sanitizer, etc.) incurred and documented by the LIURP contractors. The Company also expanded eligibility under its Operation Share grant program to 250% of the federal poverty limit ("FPL") and increased the maximum grant size from $400 to $600.

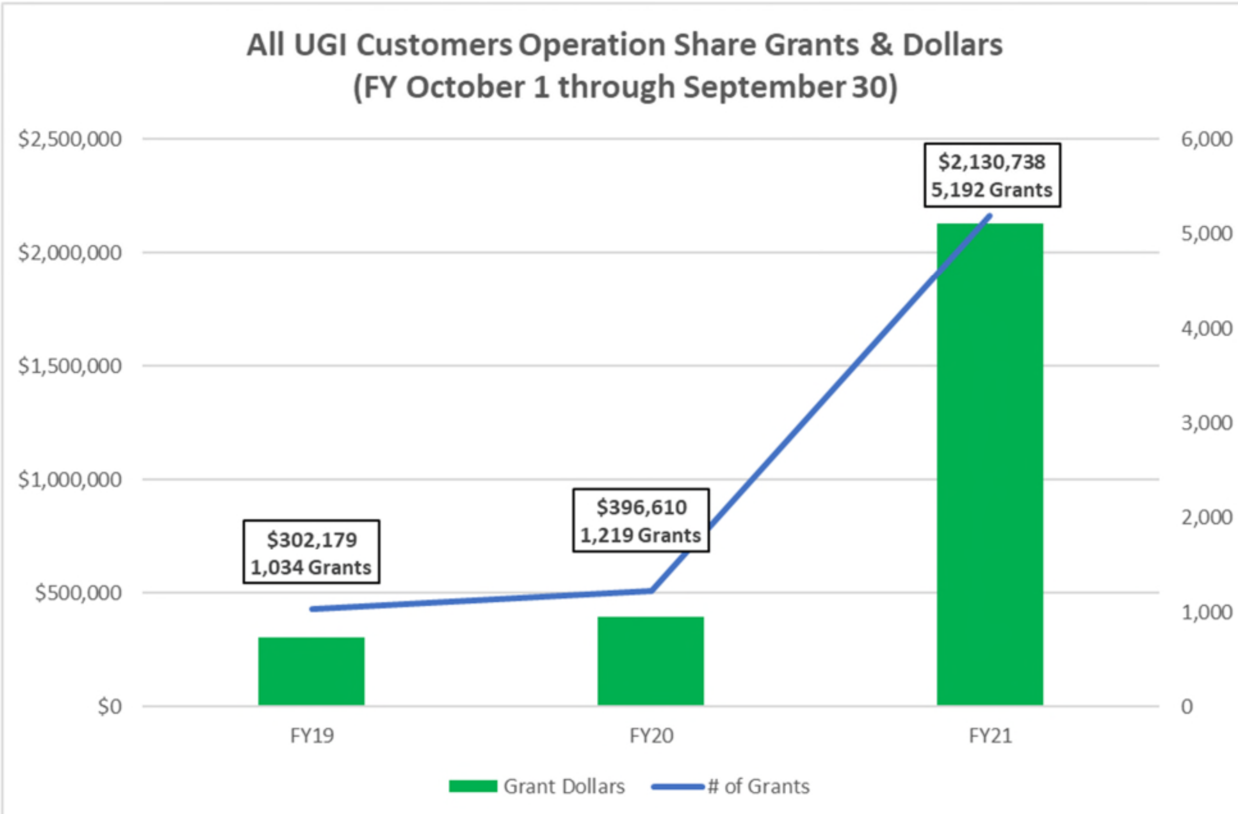
Q. Were these changes accompanied by any additional communication efforts by the Company?

A. Yes. The Company launched an extensive information and outreach campaign associated with its Pandemic response consisting of a COVID-19 Response webpage, webpages for residential and commercial customers providing additional resources, bill inserts, website-embedded customer-assistance program videos, webinars, online advertising, informational emails, and direct mail letters and postcards. The result of these efforts (in

[3] *Petition for Amendment of UGI Universal Service and Energy Conservation Plan for January 1, 2020 – December 31, 2025*, Docket Nos. M-2019-3014966 and P-2020-3019196. As of the date of this testimony, this petition remains pending before the Commission.

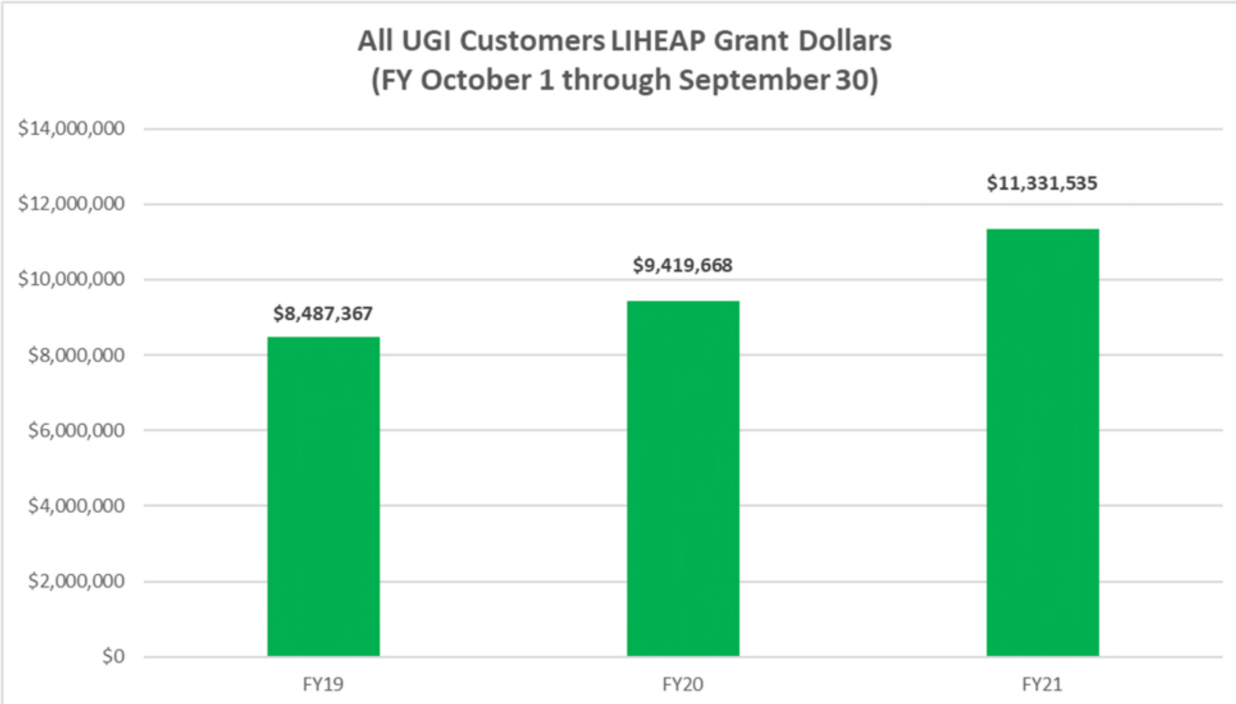
terms of Operations Share distributions and LIURP grants) are shown in Tables 3 through 4 below when comparing year-over-year results.

Table 3



Between FY 2019 and FY 2021, Operation Share grants increased by 605% (from $302,179 to $2,130,738).

Table 4



Between FY 2019 and FY 2021, LIHEAP grants increased by 34% (from $8,487,367 to $11,331,535). Additionally, the CARES Act Emergency Rental Assistance Program ("ERAP") assisted 2,377 UGI Gas and UGI Electric customers, with an average grant amount of $623 per customer. Total dollars year-to-date as of November 30, 2021 for ERAP is $1,477,366. Lastly, overall CAP enrollments increased by 16% between FY2019 to FY2021.

Q. Are there any other programs that the Company implemented to assist customers during the pandemic?

A. Yes, with Commission approval at Docket No. R-2019-3015162, the Company launched an Emergency Relief Program ("ERP") Phase I to assist natural gas customers economically impacted by the Pandemic. The program ran from October through December 2020 and provided installment payment plans for residential and business customers. It also provided an opportunity for a one-time grant of up to $400 for residential customers who either received the federal CARES Act Economic Impact Payment or filed for unemployment during the Pandemic. During the course of the program, the Company granted over $198,000 in grants to approximately 1,500 residential customers and permitted over $1.5 million in payment arrangements to approximately 1,800 customers.

On January 25, 2021, UGI Gas filed a Petition at Docket No. P-2021-3023839 to establish ERP Phase II. The Company proposed continuing the temporary, voluntary modifications to the USECP, established in ERP Phase I, in light of the ongoing COVID-19 Pandemic. Pursuant to the Commission's Order, which entered on October 28, 2021, UGI Gas was permitted to maintain the modifications to its hardship funds, which were established in ERP Phase I through the end of 2021. These modifications included expanding eligibility for hardship funds to households with income up to 250% of the FPL and increasing the maximum hardship grants from $400 to $600, to the extent funds are available.

V. UNIFICATION OF RATES AND REPORTING

Q. Has UGI Gas altered its rate structure, tariff, and rate classes in recent years?

A. Yes. Over the past few years, as a result of UGI Gas integrating three former separate NGDCs, the Company has taken many steps toward unifying its rate structure, tariff, and rate classes. This effort was undertaken to both increase efficiencies within the Company and provide the same tariffed services to customers at the same rates throughout the Company's service territory. The intra-company merger of 2018 (described below) was the first step in this process of unification.

Q. Please describe the Company's merger of its prior NGDC subsidiaries.

A. Prior to October 1, 2018, UGI Gas had two wholly-owned subsidiaries which were Commission-certificated NGDCs. Those subsidiaries were UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas, Inc. ("UGI CPG"). On March 8, 2018, UGI Gas filed a petition with the Commission at Docket Nos. A-2018-3000381 *et al*. to approve the merger of UGI PNG and UGI CPG into UGI Utilities, Inc., and the subsequent operation of UGI Gas as three rate districts under the three former tariffs of UGI Gas, UGI PNG, and UGI CPG. The Commission approved a settlement of that proceeding in an Order entered on September 20, 2018. The merger was completed on October 1, 2018, and UGI Gas commenced operations under the three-rate district structure described above with (a) three sets of base rates; (b) three gas supply portfolios; (c) three PGC rates; (d) three sets of rules applicable to Natural Gas Suppliers ("NGSs") serving Choice and Non-Choice customers; and (e) three tariffs. This successful merger positioned the Company to then move forward with further harmonization of tariffs and rates.

Q. Please describe those efforts to harmonize its tariff offerings and rate schedules after the 2018 merger.

A. In January 2019, the Company filed for a base rate increase at Docket No. R-2018-3006814 ("2019 Rate Case"). In that proceeding, the Company proposed to operate under a single uniform tariff with uniform residential and commercial base rates and associated surcharges and riders across its system.

Q. Was the Company's proposal to unify rates in the 2019 Rate Case approved?

A. In very large part, yes. The Company's proposal to unify rates was approved by the Commission in an Opinion and Order entered October 4, 2019, with the exception of the unification of former North Rate District and South/Central Rate District rates for both Rates N/NT and Rate DS. This resulted in rate unification for over 97% of all UGI Gas customers and permitted the Company to propose a two-step process to address final unification for both Rates N/NT and Rate DS across all former rate districts.

Q. Please describe the two-step process to unify Rates N/NT and Rate DS that was approved by the Commission as part of the 2019 Rate Case.

A. For Step 1, upon the effective date of new rates in the 2019 Rate Case, the Commission approved a twelve (12) percent increase to Rates N/NT (North Rate District rates) and a twenty (20) percent increase to Rate DS (North Rate District rates), with Rates N/NT and Rate DS (South and Central Rate Districts) set uniformly by class to recover the remaining N/NT and DS revenue requirements, respectively. As part of Step 2, the Company was permitted to propose full uniform rates for these two rate classes in the Company's next general rate proceeding, which the Company did propose in its 2020 Rate Case at Docket No. R-2019-3015162.

Q. Was the Company able to make Rates N/NT and DS uniform in the last base rate case filed in 2020?

A. No. In paragraph 45 of the Joint Settlement Agreement of the 2020 Gas Base Rate Case ("Settlement"), the Company withdrew its proposal to fully harmonize distribution rates for Rates N/NT and DS without prejudice. Additionally, UGI Gas reserved its right to propose unification of these rates in this proceeding.

Q. What is the Company's proposal in this proceeding with respect to Rates N/NT and Rate DS?

A. The Company proposes to take the final step to merge both Rates N/NT and Rate DS across all former rate districts by merging the rates in place for the geographic footprint of the former North Rate District with those of the former Central and South Rate Districts at this time. The Company's proposal for rate design for all customers, including the final unification of DS and N/NT customers, is described in more detail in the Direct Testimony of Sherry A. Epler (UGI Gas Statement No. 8). The Company believes that this proposed final stage of rate harmonization is fully consistent with the principles of rate gradualism given the magnitude of the proposed increases to impacted customers and the extended period of time which will have lapsed since the Company's initial unification efforts began in 2019.

VI. <u>UGI-1 INITIATIVE AND UNITE</u>

Q. Please describe UGI Gas's UGI-1 initiative.

A. UGI-1 is a Company-wide improvement initiative focusing on improvements in the area of people, tools, and processes. The Company is building on its past focus on distribution system modernization by taking advantage of newer technologies, equipping employees for future success, and improving organizational communication. The centerpiece of UGI-1 is UNITE, a multi-phased series of projects to identify and address business and technology opportunities for improvement. The Company has completed multiple UNITE phases to date and is presently engaged in a current-state analysis review of the Company's asset management processes.

Q. Has the UGI-1 initiative benefitted customers?

A. Yes. UGI-1 has already established and implemented a number of common information systems, tools, equipment types, and uniform work management and performance platforms to support UGI's operations. This has allowed, and will continue to allow, UGI Gas to become more efficient and effective in performing all aspects of its business, including: taking calls from customers, performing billing and related activities, constructing new distribution facilities, operating and maintaining its gas distribution and transmission systems, and responding to and managing emergency situations.

Q. How has the UGI-1 initiative impacted infrastructure and safety?

A. Under UGI-1, UGI Gas applies a common set of initiatives in workplace safety. The Company's standardized approach to training and safety culture, and in particular, its development of a comprehensive and centralized training center and creation of a safety and health management system, ensures that all Company employees share common values regarding safety and are trained in a consistent manner throughout the Company's service territory. The Company also uses this fully consolidated approach to the work identified in its Second LTIIP and is achieving improved distribution system safety based on measurable performance criteria. During the five-year term of its current Second LTIIP (2020-2024), UGI Gas is investing approximately $1.3 billion on infrastructure improvements, building off an already-successful LTIIP that has realized material reductions to the number of hazardous and non-hazardous leaks.

Q. What is the UNITE initiative?

A. The UNITE initiative is an effort to modernize and harmonize the Company's information technology systems.

Q. Please explain the improvements that the Company has made as part of UNITE.

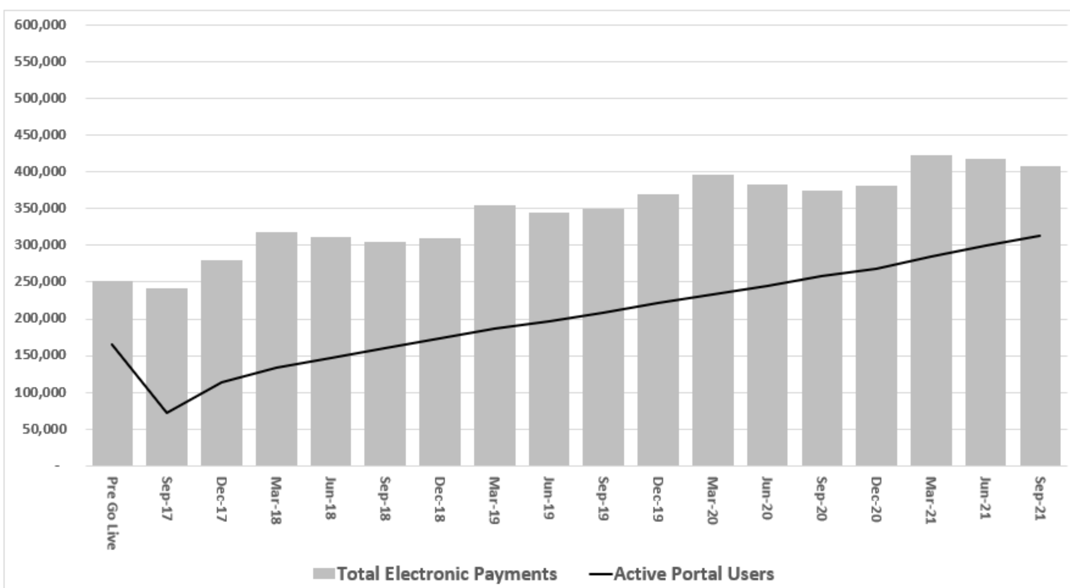
A. Phase I of UNITE replaced UGI's Customer Information Systems ("CIS") in September 2017. Since then, UGI has seen a 62% increase in electronic payments, and customers with portal profiles have increased by 88%. These statistics indicate improved customer experience and a reduction in the customer effort needed to access information and services. The upwards trend of electronic payment adoption can be seen in Figure 5. Also, as seen in Figure 6, after a brief post-implementation period, during which the Company adapted and fine-tuned its new CIS, the Company has improved its customer service with respect to certain customer service metrics, including grade of service (calls answered within 30 seconds), as compared to pre-CIS implementation. Additionally, self-service utilization rates, first call resolution, and contact center customer effort indicators have all improved over the last few years.

Phase II of UNITE, which went live in July 2019, replaced the Company's Enterprise Resource Planning ("ERP") system and introduced SAP's Fieldglass solution for contractor billing. Since the implementation in 2019, internal controls have been enhanced through the increased use of electronic purchase orders (59% increase) as well as automated wire payments, approval routings, and user access provisioning.

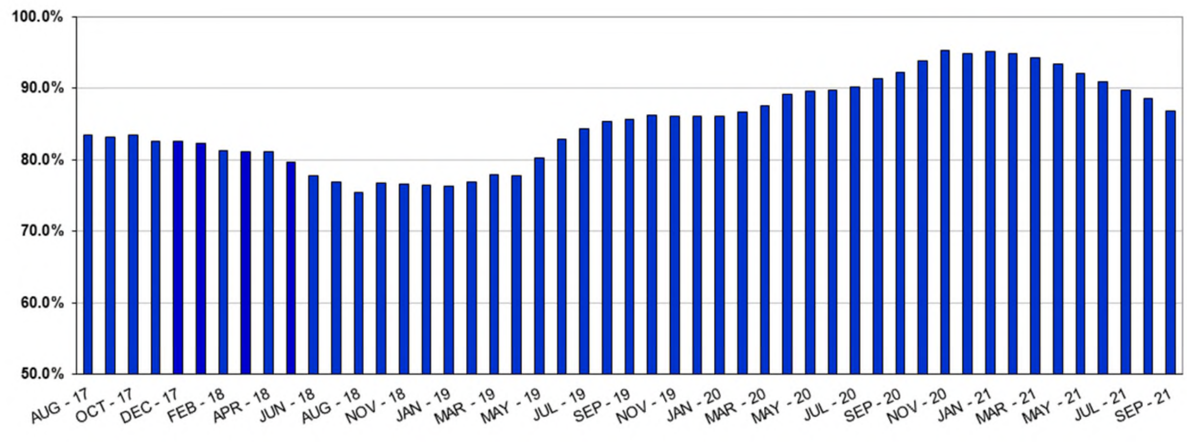
Additionally, the Company has achieved efficiency in operations by reducing invoice processing time (50% reduction in overdue invoices) and utilizing radio frequency barcode scanners in the Company's central warehouses.

Phase III of UNITE, the Enterprise Performance Management ("EPM") project, went live in October 2020 and implemented the PowerPlan Capital Budgeting and Forecasting solution integrated with the Company's ERP and PowerPlan Fixed Asset and Tax systems. PowerPlan provides embedded lifecycle governance for approving and monitoring capital projects; improved visibility of capital expenditure requests and authorized capital projects; detailed forecasting for more accurate tracking of ongoing capital projects; and improved data analytics for making timely and optimal capital decisions.

<u>Table 5 Customer Electronic Payments and Website Portal Utilization – September 2017 through September 2021</u>



<u>Table 6 Combined Customer Service Performance - Grade of Service[4]</u>
<u>Rolling 12-Month Average from August 2017 through September 2021</u>



Q. Please describe the UNITE current state analysis of the Company's asset management processes.

A. The current state analysis is a key element of UNITE's current EAM project, a multi-year, multi-phase project with the end goal of a new EAM and supporting applications. In mid-2021, the Company kicked off the EAM's asset data collection phase, which focuses on the identification and standardized capture of asset data information across UGI. The asset data collection phase is planned to go live for UGI Gas in January 2023. In the next phase, the Company will be kicking off EAM's asset management, work management, and field service management projects. The current state analysis enables UGI to understand processes and process variation across the Company, document future state recommendations from key business stakeholders, and begin setting the stage for the EAM transformation. These activities provide a critical base understanding for the UNITE team's pre-design workshops and are beneficial interactions with business stakeholders.

4 Grade of Service is the percentage of customer calls answered within 30 seconds of receiving the call and is a common measurement of call center performance and customer satisfaction.

The UNITE EAM program is described further in the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 5).

Q. What processes are being evaluated in this current state analysis for UGI Gas?

A. Specific gas processes within the scope of this current state analysis include: main replacement, distribution system reinforcement, and line extension projects; service installations; as-built tracking and traceability; record corrections; new and upgraded regulator stations; inspections, maintenance and other repairs; paving and restoration; and facility locates and damage prevention.

Q. What process and system-related improvements does UGI Gas expect to derive from the current UNITE EAM initiative?

A. The current state analysis on process documentation will feed into the design for a new EAM to leverage the same tools for similar processes that occur across UGI. One goal will be eliminating obsolete IT systems and paper-based processes, while providing automation to improve reliability and streamline operations. With respect to systems, the new EAM will be integrated with a consolidated gas and electric Geographic Information System ("GIS"), and other systems, such as CIS, ERP, and EPM discussed above. The EAM will be a central repository for housing, analyzing, and accessing UGI assets and managing full asset lifecycle information. The benefits derived from the EAM implementation will include, among others, standardized business processes across the Company; improved data quality; improved IT system maintainability; better facility tracking and traceability; tools for ensuring ongoing regulatory compliance; a standard dispatching and mobility solution for field work; enhanced work management capabilities; mapping upgrades and digitized infrastructure as-builts; and improved portfolio and risk management capabilities for guiding future betterment decisions. While the Company is at the beginning phase of its multi-year EAM project, the foundational work being performed at this stage will ensure a solid platform upon which to create a comprehensive and integrated EAM framework.

Q. What will be the focus of the UNITE EAM initiative in the FPFTY?

A. The Company will be implementing the asset data collection project to the field in the FPFTY, rolling out improved data collection tools, systems, and utilizing the improved data and systems which form the foundation for the broader EAM initiative. The Company will be targeting the next portions of EAM (Asset Management, Work Management, Field Service Mobility, and GIS) with a goal of placing those programs in service in the following fiscal year.

VII. AUBURN CAPACITY LEASE

Q. Please describe the Auburn Capacity Lease.

A. On November 22, 2021, the Commission approved, via secretarial letter at Docket No. G-2021-3028753, a new Capacity Lease Agreement allowing the Company direct access to natural gas supplies for delivery from the Tennessee Gas Pipeline through the UGI Gas Auburn Gate Station into the Auburn Gathering system, a natural gas gathering system located in northeast Pennsylvania, owned by UGI Energy Services, LLC (an affiliate of the Company). This new capacity lease will expand the available sources of reliable and competitively priced supplies for the Company and its customers.

Q. When does the Company anticipate the capacity lease going into service?

A. The Company currently anticipates the capacity lease becoming available on July 1, 2022.

Q. How were the costs of the capacity lease treated in this proceeding?

A. Since the largest customer served by UGI Gas from the Auburn Gathering System is The Proctor and Gamble Paper and Products Company, a Rate XD customer, it is appropriate that the anticipated costs for the new lease be assigned to the Rate XD customer group. The direct assignment of these costs has been reflected in UGI Gas Exhibit D, the ACOSS, as it is consistent with the principle of cost causation; appropriate adjustments to Rate XD revenue have also been incorporated as explained in the direct testimony of Sherry A. Epler (UGI Gas Statement No. 8).

VIII. SALARIES AND WAGES ADJUSTMENTS

Q. Is the Company making any adjustments to Salaries and Wages not included in the FPFTY budget?

A. Yes, Schedule D-9 includes total salary and wage increase adjustments of $1.91 million. The first adjustment (Adjustment #1) in the amount of $1.32 million shown on Schedule D-9 is for unbudgeted compensation and benchmarking adjustments to salary and wages. The Company is making these adjustments as a result of recent compensation benchmarking review activities that focused on how UGI Gas may continue to remain productive in an increasingly competitive labor market. This is of critical importance as the Company continues to look to ensure its efforts to attract, recruit, train and retain those professional, technical and field-qualified personnel and resources necessary to implement, operate, and maintain a safe and reliable natural gas distribution system for all customers.

The second adjustment (Adjustment #2) shown on Schedule D-9 is in response to the Transportation Security Administration ("TSA") Cyber Security Directives 2021#1 and 2021#2 (further described below).

Q. Please describe the compensation benchmarking adjustments that the Company is making in this case.

A. The Company has reviewed current exempt and non-exempt employee compensation levels against benchmark data provided by the American Gas Association ("AGA") and has begun to implement salary adjustments based on this study. These planned adjustments affect 990 employees and will result in $1.2 million of incremental cost to be applied to the Company's operating expense for UGI Gas in the FPFTY, and accordingly is shown as an adjustment on Schedule D-9 plus incremental employee benefits.

Q. Please describe the needs which are being addressed by the compensation adjustments that you described?

A. Like many companies in the current labor market, UGI has experienced an increase in voluntary employee turnover as the available labor market has become constrained and increasingly competitive. This is particularly true for roles that require experienced employees. As a result of the current job market, more employees, including those with years of regulated utility experience, are moving on to other opportunities outside of UGI. In addition, in some instances, the Company encountered difficulties finding internal interest for certain critical exempt positions. For instance, experienced non-exempt employees (e.g., long term field employees) have declined taking operational field supervisor roles due to the lack of adequate pay differential between these roles when factoring in overtime and premiums. This has caused the Company to often look externally to fill critical positions, casting a wide geographic net in order to find suitable, experienced candidates to fill these critical roles. As this has occurred, the Company has also engaged external search agencies to assist in finding the candidates for UGI's needs, which adds considerable time and expense to the recruiting process. The purpose of implementing these adjustments is to improve UGI's ability to: (1) retain existing experienced employees; and (2) compete for qualified employees in order to fill needed roles in a very competitive job market.

Q. Can you please provide a summary of the compensation benchmarking adjustments?

A. Yes, the chart below outlines the number of employees affected by these compensation adjustments, by functional department and includes operating expense and incentive compensation adjustments based on the employees' predetermined time allocations.

Table 7: Compensation Benchmark Adjustments by Functional Department

	Count of Employee ID	Total Pay Change	Gas OPEX Total FY2023	Gas OPEX Management Incentive Total FY2023
Accounting, Acts Payable, Admin, Billing, Bldg & Grounds, Business Support Services, Finance, Fleet	89	$103,565	$67,614	$ 3,057
Capital Planning, Capital Program Mgt, Construction, Dispatch, Meter Shop, Operations, Pipeline Safety	253	$699,977	$403,594	$28,935
Engineering, GIS, Telemetry, Environmental, Safety	178	$371,087	$51,504	$ 3,290
Customer Care	158	$43,710	$307,664	$653
HR, IT	125	$440,168	$298,536	$14,798
Communications, Community Relations, Sales & Marketing	92	$17,797	$4,539	$111
Procurement, Rates, Supply	39	$78,373	$13,635	$541
Business Process Improvement, UNITE, Training	56	$7,550	$719	$72
Totals	990		$1,147,806	$51,457

Q. How did the Company arrive at the summary adjustments shown above?

A. As I stated above, the Company reviewed salary data provided by AGA by position and then compared current individual employee compensation levels to the AGA midpoint by role, or other survey data where a job match could not be identified utilizing AGA data. The use of the AGA midpoint survey data comports with the Company's goal to establish compensation at the fiftieth percentile level. Years of service was used as the guideline for employee compensation to create anticipated service requirements that link with targets that are approximate to the midpoint of the salary recommendations. Compensation targets were then identified based on years of service, in order to determine which specific employees warranted adjustments. The adjustments were made in relative increments against the midpoint compensation levels, above (over 5 years of service) or below (less than 5 years of service) accordingly. Increases are planned to be phased-in beginning in early 2022 and are expected to be completed by September 2022.

Q. Please explain the Cyber Security adjustment in Schedule D-9 (Adjustment #2)?

A. These staff additions are in direct response to the TSA cybersecurity directives, which were issued in May[5] and July 2021[6] to protect against the impact of malicious cyber intrusions affecting the nation's pipelines. The directives include approximately 90 specific required actions to be applied to information and operational technology systems. The Company has identified that five additional full-time employees are required to support these new TSA cybersecurity directive requirements – four additional cybersecurity professionals and

5 *See* https://windot.com/docs/rus/rus32wdw/PDF/TSA_security-directive-on-enhancing-pipeline-cybersecurity_(002).pdf

6 *See* https://www.dhs.gov/news/2021/07/20/dhs-announces-new-cybersecurity-requirements-critical-pipeline-owners-and-operators. UGI Gas notes that this second directive on cybersecurity is restricted from public disclosure and was sent directly to designated owners and operators.

one systems administrator. This additional cybersecurity and infrastructure staff will be needed for the administration and management of the new cybersecurity procedures and supervisory control and data acquisition system ("SCADA") environment as cyber professionals will monitor threats and protect the isolated SCADA network. Additionally, cyber analysts will be required to manage the new cybersecurity appliances (firewalls, network access control, and endpoint protection) and will be required to support vulnerability management and patching requirements. The five positions are being added at the identified median salary plus employment benefits. Based on discussions that the Company has had with other utilities and the AGA, UGI's proposed staffing aligns with other utilities that are taking the same approach to satisfy the TSA requirements.

IX. <u>MANAGEMENT EFFECTIVENESS AND PERFORMANCE</u>

Q. What actions has UGI Gas taken that reflect superior management performance?

A. UGI Gas has focused on a number of areas to enhance and improve the quality and effectiveness of its service in recent years that reflect superior management performance. These management efforts include: (1) excellent customer service; (2) infrastructure improvements made pursuant to the Company's LTIIP; (3) investments in safety; (4) IT modernization; (5) environmental initiatives; (6) community engagement; and (7) diversity and inclusion.

Q. Please describe the Company's achievements in providing superior customer service.

A. Many industry experts have recognized UGI for its excellent customer service. Including 2020, UGI finished in first or second place in the J.D. Power award for customer satisfaction among utilities in each of the last nine years and won the J.D. Power #1 in

Customer Satisfaction award a total of seven times (2003, 2004, 2005, 2006, 2007, 2013 and 2014) since UGI was first included in the survey in 2003 by J.D. Power. Most recently, UGI was among 38 utility companies nationwide that were named a 2021 "Customer Champion" based on the Cogent Syndicated Utility Trusted Brand & Customer Engagement™ Residential study from Escalent, a human behavior and analytics firm. This is the fourth consecutive year that UGI has received this award.

Q. What infrastructure improvements has the Company achieved?

A. As further explained in the testimony of Timothy J. Angstadt (UGI Gas Statement No. 9), UGI Gas has an aggressive accelerated infrastructure replacement plan focused on replacing all remaining cast-iron and bare steel mains. UGI Gas is a leader in the Commonwealth, with the highest percentage of contemporary mains among major NGDCs at almost 90%. The Company projects that it will eliminate all cast-iron mains by 2027 and all bare steel mains by 2041. The Company's infrastructure improvement statistics, exemplified by the reduction of leaks and cast iron breaks discussed in Mr. Angstadt's testimony, is a direct result of this aggressive accelerated infrastructure replacement plan.

Q. Please describe the Company's investments in Safety Culture Development and Training.

A. The Company constructed a comprehensive and centralized training center in Berks County, which now serves as the heart of the Company's training programs and provides real-life and simulated training scenarios to ensure that UGI Gas's personnel are providing customers, communities and first-responders with enhanced service in the field. The

Company has also developed and implemented numerous safety focused initiatives, as further explained in the testimony of Timothy J. Angstadt (UGI Gas Statement No. 9).

Q. Did UGI receive any industry recognition on safety initiatives in 2021?

A. Yes. UGI Gas was the winner of the 2021 American Gas Association Safety Awareness Video Excellence ("SAVE") award. The SAVE award recognizes outstanding contributors to natural gas communications on safety and education. UGI's entry, "Slips, Trips & Falls" featured many of the Company's own employees.[7]

Q. Please describe the Company's efforts at modernizing processes and Information Technology.

A. As described earlier in my testimony, Phase I and Phase II of the UNITE Project to upgrade the Company's CIS and ERP systems have been implemented and the Company is now focused on UNITE Phase III, which will begin a long-term process of upgrading the Company's capital management systems. The Company has spent the last five years dedicating significant time and resources to modernize its information systems in order to increase its operating efficiency and to provide its customers with better service.

Q. Please describe the Company's engagement on environmental and social governance ("ESG") initiatives.

A. The Company, as well as its parent UGI Corp., are committed to environmental stewardship and social consciousness keenly focused on people and the planet. As explained below, UGI Gas continues to have ESG as a significant area of focus.

7 *See:* https://www.youtube.com/watch?v=PV4zKShr16w

Q. What actions has UGI Gas taken to address environmental stewardship?

A. UGI Gas itself encourages energy efficiency through its voluntary EE&C programs. Since 1995, the Company has successfully converted more than 115,000 customers, mostly from fuel oil, to more environmentally-friendly natural gas. UGI Gas has also connected service to new natural gas generating facilities that, in part, have enabled the Commonwealth to substantially lessen its reliance on electric generation produced by more carbon-intensive fuels such as coal and oil. UGI Gas also has encouraged the adoption of environmentally-friendly natural gas through the recent line extension tariff revisions adopted in the 2020 Gas Rate Case, which, under certain conditions, waives the contribution for customers whose properties are within 150 feet of an existing gas main. Additionally, UGI Gas has over 100 compressed natural gas fueled vehicles as part of its fleet, with plans to add nearly 100 more by the end of the FPFTY, which provide significant reductions in carbon emissions. The Company's cast iron and bare steel replacement activities also have resulted in lowering methane emissions. Finally, as mentioned previously, UGI Gas has been actively implementing options that reduce its carbon footprint, including a program that incorporates renewable natural gas into its distribution system and gas supply portfolio.

Q. What efforts has UGI Gas made toward sustainability?

A. UGI Gas increased its focus on sustainability as it pertains to the natural gas industry. To support the expansion of sustainability overall, the Company has joined and is participating in several collaboratives, councils, and associations related to improving the sustainability of its natural gas sourcing practices. These include:

- The Natural Gas Supply Collaborative, an organization of natural gas purchasers, provides technical expertise and guidance on emerging technologies and gas supply initiatives. Members include utilities and power generators committed to responsible practices for and safety of procuring natural gas supply.

- Our Nation's Energy ("ONE") Future, an industry group that focuses on the goal of reducing methane emissions across the natural gas value chain.
- The American Biogas Council, the only national trade association representing the entire U.S. biogas industry. The American Biogas Council focuses on the biogas supply chain and is dedicated to maximizing the production and use of biogas from organic waste.
- The Coalition for Renewable Gas, a public policy advocate and education platform for RNG in North America.
- NextGenGas Coalition, a collaborative effort to facilitate external engagement and educational opportunities to accelerate the successful advancement of the NextGenGas marketplace.

The Company plans to continue to enhance and expand its ESG initiatives aimed at lowering methane and greenhouse gas emissions.

Q. Please describe the Company's community engagement efforts.

A. Each year, UGI Gas invests more than $1.0 million to support education improvement programs across the Company's service territory. UGI Gas also supports: childhood literacy; enhanced "STEM" (science, technology, engineering and math) curriculum in elementary schools; funding for technical training programs for high school students; and programs that provide support and mentoring for women and minority engineering students. UGI Gas employees also commit significant personal time and resources to support community initiatives. UGI Gas's employees are eligible for 16 paid hours of volunteer time per year per the Company's volunteer policy. For example, 394 UGI Gas employees donated more than 31,000 hours combined of work and personal time to assist their communities in 2020. Company time keeping records show that 99% of this volunteer time was personal time volunteered by its employees; a strong demonstration of the community commitment UGI Gas and its employees have across the Company service territory. UGI (both Gas and Electric) employees also donated personal funds to better their communities. More than 1,000 employees contributed a total of more than $339,000 combined as part of the Company's 2021 United Way campaign. Combined with corporate contributions and retiree contributions, total support provided to United Way agencies serving communities in the UGI Gas service territory in 2020 totaled more than $551,000. UGI Corp. was recently named an honoree of the 2021 Civic 50 Greater Philadelphia by Philadelphia Foundation, in partnership with Points of Light and local partners, for its superior corporate citizenship. In addition, UGI was named the Cogent Syndicated 2021 Most Trusted Utility Brand and "2021 Easiest to do Business with" by Escalent.

Q. What actions has UGI Gas taken to address diversity and inclusion?

A. UGI Gas is committed to fostering a more diverse and inclusive work environment, which will provide a stronger and more cohesive workforce that ultimately provides improved service to our customers. As part of this focus, UGI has implemented a Belonging, Inclusion, Diversity and Equity ("BIDE") initiative. BIDE was formed in 2020 to enhance and expand UGI Gas's efforts to be "part of the solution" in addressing systemic racism and injustice in the communities in which it operates. Utilizing the Company's core values – safety, integrity, respect, responsibility, reliability, and excellence – UGI Gas has implemented steps to model inclusive leadership and provide a culture in which employees feel a sense of belonging. To effectively implement the objectives of BIDE, UGI Gas has created a council that includes senior leadership dedicated to increasing inclusivity and diversity in four core pillars of the business: Culture, Career, Community, and Commerce. The BIDE initiative seeks to provide employees with a safe, welcoming, and inclusive work environment, and shows the Company's commitment to enhancing its efforts to attract, retain, and develop a more diverse team at UGI Gas.

Q. What resources has the BIDE initiative provided to UGI employees?

A. As part of its focus on creating a culture of inclusion, UGI's BIDE initiative has developed three employee resource groups: Black Organizational Leadership and Development ("BOLD"), Women's Impact Network ("WIN"), and the Veteran Employee Team ("VET"). BOLD focusses on inclusion, equity, education, and empowerment for black employees and will assist leadership with communication, talent recruitment and retention, and promotion for black employees. BOLD drives professional development through mentoring and sponsorship opportunities, increasing exposure through networking and career development events. It also promotes cultural transformation by influencing Company policies and procedures that can improve an employee's experience at UGI, as well as the impact these policies and procedures have on customers and partners. WIN fosters an environment for women to be recruited, retained, developed, and advanced as leaders within the UGI Family of Companies. Membership in WIN offers exposure to various professional development opportunities, including speaker series events, group engagement activities, virtual group discussions, and partnerships with local organizations. VET recruits and retains veterans and fosters goodwill towards veterans. Members include

Active Duty, Reserve, and National Guard veterans of the Army, Navy, Marines, Coast Guard, and Air Force, their families, and partners committed to supporting military veteran employees. These three groups provide support, mentorship, educational opportunities, advocacy, and events to increase awareness and involvement and to grow the culture of inclusion at UGI Gas.

Q. What additional actions has UGI Gas taken as part of its BIDE initiative?

A. In addition to employee resource groups, UGI Gas has continued to refine its efforts to hire and retain diverse employees, including more senior level positions. This effort includes consideration of a diverse slate of candidates for all director level or higher roles. BIDE has also incorporated UGI's long-time focus on developing relationships with diverse suppliers and vendors. The Company has continued its efforts to contract with Minority, Women and Disabled Owned Businesses ("Diversity Spend"). Historically, UGI has acquired diverse supply partners through various methods. The Company has implemented employee education and training, utilized the support of relevant database tools, incorporated diverse vendors into its requests for proposals ("RFP"), and provided guidance on entering into agreements with diverse outfits.

In calendar year 2020, UGI Corp. began the centralization of the procurement function of its various business units. This centralization will enable development of a cohesive supplier diversity policy for UGI Gas and its affiliates, which will incorporate supplier diversity spend goals. UGI Corp. has taken the initial step of creating a supplier diversity team across all business units that will further this effort. UGI Corp. has also named a supplier diversity executive to lead the program globally.

For 2021, Total Diversity Spend by UGI was in excess of $59 million. In addition, in November 2021, UGI served as the premier sponsor of the Pennsylvania Diversity Coalition's inaugural supplier diversity summit for utilities. The event was designed to forge relationships between minority business enterprises with non-diverse companies that serve natural gas, electric and water utilities. Many of the participants agreed that matchmaking events are critical in increasing accessibility to diverse businesses.

Q. What benefits do a diverse workplace and supplier pool bring to UGI Gas customers?

A. Diversity provides a variety of benefits that impact the service UGI Gas provides to its customers. Workplaces that embrace diversity have been shown to have higher employee engagement, which leads to increased productivity, innovation, and creativity. Diverse work environments are better at bringing in top talent and retaining employees, which should reduce costs associated with recruiting, onboarding and training new employees over time. Having a diverse contingent of suppliers provides for resiliency in the supply chain and increases the competition for UGI Gas's business, which can be expected to lower prices and foster innovation. For these reasons, the Company's customers benefit from the Company's diversity efforts, which are reflective of the communities we serve.

Q. What do the Company's efforts in the above-referenced areas demonstrate?

A. UGI Gas believes that the management efforts described above, and the other improvements described by the UGI Gas witnesses in this proceeding, as well as the Company's provision of safe and reliable service at reasonable rates, demonstrate UGI Gas's commitment to safety, community partnership, and the provision of excellent customer service. In total, these efforts support an additional upward adjustment of 0.20%

to the Company's equity return in recognition of its management effectiveness, which is included in the 11.2% equity return requested in this proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT CRB-1

CHRISTOPHER R. BROWN

VICE PRESIDENT AND GENERAL MANAGER, RATES AND SUPPLY

UGI Utilities, Inc.

Vice President and General Manager, Rates and Supply (Denver, Pa.)	May 2019 - Present
Sr. Director- Operations South Region (Reading, Pa.)	July 2015- May 2019
Manager - Operations (Reading, Pa.)	July 2013 – July 2015
Director- Central Services (Reading, Pa.)	October 2010 – July 2013
Manager – Strategy Processes and Implementation (Reading, Pa.)	February 2010 – October 2010
Manager – Customer Accounting Services (Reading, Pa.)	May 2009 – February 2010
Marketing Manager – East Region (Allentown, Pa.)	April 2008 – May 2009

Amerigas Propane, Inc.

Market Manager (Stroudsburg, Pa.)	June 2005 to April 2008

UGI Utilities, Inc.

Supervisor – Gas Supply and Transportation (Reading, Pa.)	September 2003 – June 2005
Distribution Superintendent (Harrisburg, Pa.)	September 2001 – September 2003
Staff Engineer – Commercial Marketing (Reading, Pa.)	September 1999 – September 2001
New Business Engineer (Allentown, Pa.)	June 1997 – September 1999

Education

MBA, Lebanon Valley College, Annville, Pa.
BS, Civil Engineering, Lehigh University, Bethlehem, Pa.

Previous testimony provided before the Pennsylvania Public Utility Commission:

Docket No. R-00050539	UGI Utilities Inc. - Annual 1307(f) Filing
Docket No. C-2015-2516051	Centre Park Historic District v. UGI Utilities, Inc.
Docket No. C-2016-2530475	City of Reading v. UGI Utilities, Inc.
Docket No. R-2019-3015162	UGI Utilities, Inc. Gas Division - Base Rate Case Proceeding
Docket No. R-2021-3023618	UGI Utilities, Inc. Electric Division - Base Rate Case Proceeding

UGI GAS STATEMENT NO. 2

TRACY A. HAZENSTAB

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Gas Utilities, Inc. – Gas Division

Statement No. 2

Direct Testimony of
Tracy A. Hazenstab

Topics Addressed:	**Uniform Rate Structure and Riders**
	Budget Process
	Revenue Requirement
	Operating Revenues and Expenses
	Compliance with Act 40 of 2016

Dated: January 28, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Principal Analyst, Rates. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Principal Analyst, Rates?

A. I am primarily responsible for various tariff filings and related computations for UGI Gas and UGI Electric rate and regulatory filings before federal and state regulatory commissions. As part of these responsibilities, I am responsible for budgeting/financial planning for UGI, which is a joint effort with the Rates Department (preparing the revenue and margin budgets) and the Financial Planning and Analysis Department (preparing the operating and capital budgets). I report directly to the Director, Rates and Regulatory Planning of UGI.

Q. What is your educational background?

A. I received an undergraduate degree in International Politics from Pennsylvania State University.

Q. Please describe your professional experience.

A. Please see my resume, UGI Gas Exhibit TAH-1, which is attached to my testimony.

Q. Have you testified previously before this Commission?

A. Yes. Attached to my direct testimony is UGI Gas Exhibit TAH-1, which contains a list of the Commission's proceedings in which I previously testified. Additional exhibits that I am sponsoring are described below.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas in support of the Company's proposed revenue requirement. First, I explain the uniform rate structure that was achieved in the Company's "2019 Base Rate Case"[1] and "2020 Base Rate Case" (Part III).[2] Second, I provide an overview of the Company's principal accounting exhibits for the historic year ended September 30, 2021 ("HTY"), future year ending September 30, 2022 ("FTY") and the fully projected future test year ending September 30, 2023 ("FPFTY") (Part IV). Third, I explain UGI Gas's budgeting processes (Part V). Fourth, I present UGI Gas's ratemaking

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[1] *Pennsylvania Public Utility Commission (et al.) v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2018-3006814 (the "2019 Base Rate Case").

[2] *Pennsylvania Public Utility Commission (et al.) v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2019-3015162 (the "2020 Base Rate Case").

presentation for the FPFTY, including its revenues and operating expenses claims, and certain pro forma adjustments (Part VI). The Company's rate proposal in this case is predicated on its FPFTY exhibit, which demonstrates the need for a revenue increase of $82.7 million. I also address the Company's compliance with Act 40 of 2016 (Part VII).

Q. Ms. Hazenstab, are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to UGI Gas Exhibit TAH-1 mentioned above, I am sponsoring UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Historic). Other Company witnesses present testimony in support of various portions of these exhibits, including rate base (Vivian K. Ressler, UGI Gas Statement No. 3), operating revenue (Sherry A. Epler, UGI Gas Statement No. 8), fair rate of return (Paul R. Moul, UGI Gas Statement No. 6), depreciation expense (John F. Wiedmayer, UGI Gas Statement No. 4), salary and wage adjustments (Christopher R. Brown, UGI Gas Statement No. 1), and taxes (Nicole M. McKinney, UGI Gas Statement No. 7). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the master list accompanying this filing.

III. UNIFORM RATE STRUCTURE AND RIDERS

Q. Prior to the 2019 Base Rate Case, did the Company have consolidated and uniform distribution and purchased gas cost rates?

A. No.

Q. Please explain the rate structure that was approved by the Commission in the Company's 2019 Base Rate Case and 2020 Base Rate Case.

A. In the 2019 Base Rate Case proceeding, the Company proposed a consolidated revenue requirement and a uniform rate structure to reflect its common management, common practices/procedures, common financing, and common systems more accurately. The Commission's Opinion and Order (entered on October 4, 2019) in the 2019 Base Rate Case approved a settlement agreement among the major parties, which, among other things, consolidated the Company's revenue requirement and moved most rate classes to uniform distribution and purchased gas cost rates. In the Company's 2020 Base Rate Case, the remaining unconsolidated distribution rates for rate classes N, NT, and DS were moved closer to parity. In this proceeding, the Company proposes to complete the rate unification process, as further described by UGI Gas witnesses Christopher R. Brown (UGI Gas Statement No. 1) and Sherry A. Epler (UGI Gas Statement No. 8).

IV. OVERVIEW OF PRINCIPAL ACCOUNTING EXHIBITS

Q. Please describe the principal accounting exhibits used to support UGI Gas's claims in this proceeding.

A. UGI Gas Exhibit A (Fully Projected) provides the calculation of the revenue requirement for the FPFTY, including principal accounting exhibits, rate base claims, revenue at present rates, operating expense claims, taxes and certain *pro forma* adjustments. The FPFTY information is derived from UGI Gas's operating and capital budgets for the 12-month period ending September 30, 2023. UGI Gas Exhibit A (Future) is the principal accounting exhibit for the FTY, including certain *pro forma* adjustments. The FTY information is derived from UGI Gas's operating and capital budgets for the 12-month period ending

September 30, 2022. UGI Gas Exhibit A (Historic) is the principal accounting exhibit for the HTY, with appropriate ratemaking adjustments. The HTY information is derived from the book accounting data for the 12-month period ended September 30, 2021. The future and historic schedules are provided as a benchmark for comparison with the FPFTY claim, which, as explained above, is the basis for UGI Gas's proposed revenue increase of $82.7 million.

Q. Please provide an overview of UGI Gas's principal accounting exhibits.

A. As noted above, UGI Gas's claims in this case are based on UGI Gas Exhibit A (Fully Projected). This presentation is comprised of four sections:

<u>Section A</u> summarizes UGI Gas's requested *pro forma* rate base, revenues, and expenses at present rates and the calculation of its requested revenue increase.

<u>Section B</u> includes basic accounting data extracted from UGI Gas's financial, accounting, operating and capital budgets, and other records. This data includes a balance sheet, a statement of net operating income and test year revenues, a schedule of expense items by cost element, and a tax expense calculation. Also included are schedules showing UGI Gas's embedded cost of debt, year-end capital structure and overall claimed rate of return.

<u>Section C</u> provides the elements of UGI Gas's rate base claim and how each element of that claim is derived. UGI Gas's rate base includes utility plant in service, gas storage inventory, cash working capital, materials and supplies inventory, and offsets for accumulated depreciation, accumulated deferred income taxes, and customer deposits.

<u>Section D</u> presents UGI Gas's revenues and expenses on a *pro forma* ratemaking basis. Necessary adjustments to budgeted levels of expense items and revenues are summarized in Schedules D-1 through D-2 and detailed in the remaining schedules. The resulting FPFTY expense and revenue levels are shown on Schedule D-3 and were used to establish UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1.

Q. What information is included in UGI Gas Exhibits A (Historic) and A (Future)?

A. UGI Gas Exhibits A (Historic) and A (Future) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the fiscal year ended September 30, 2021, and the fiscal year ending September 30, 2022, respectively. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing the FPFTY claims with actual and projected results from the HTY and FTY.

Q. What are the data sources for the UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic)?

A. This data is derived from UGI Gas's books and records as well as its capital and operating budgets. UGI Gas Exhibit A (Future) is based on adjusted budgeted data for the FTY. UGI Gas Exhibit A (Historic) is based on adjusted experienced data for the HTY.

V. <u>BUDGETING PROCESS</u>

Q. Please explain UGI Gas's budgetary preparation and approval process.

A. UGI Gas's fiscal year begins on October 1 and ends on September 30 of the following year. Preparation of the UGI Gas Operating Budget for the subsequent fiscal year begins during the spring, *i.e.*, the budget process for the October 1, 2021 through September 30, 2022 fiscal year begins in the spring of 2021, with information being requested and incorporated from all departments. Internal reviews and revisions occur throughout the spring and summer before the final budget is approved by the UGI Board of Directors in September – immediately prior to implementing the budget.

The revenue portion of the budget is a joint effort between the Marketing, and Financial Planning and Analysis ("FP&A") departments. The Marketing department provides customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The FP&A department develops normalized usage per customer for core customer classes, annualized sales, and total revenues (as further explained in the direct testimony of UGI Gas witness Ms. Epler (UGI Gas Statement No. 8)). The number of customers by customer class is determined using a wide range of factors, including trends in usage, the level of applications and inquiries for service from existing customers, new construction, and shifts in type of residence and customer mix. Usage per customer is developed by reviewing the long-term usage trends and current and anticipated levels of operation. The budgeted number of customers and usage per customer are combined to produce monthly budgeted sales. The revenue budget is calculated by applying tariff rates for each customer class to budgeted sales, plus an adjustment for unbilled revenue. The sales and revenue budget is then reviewed with and approved by senior management.

Concurrently, the expense portion of the Operating Budget is prepared. Operating and maintenance expenses are developed by each functional manager based upon review of trends, monthly expenditure patterns, and new or changed programs. Employee levels are reviewed, and appropriate staffing levels are set for the upcoming fiscal year. The direct expense portion of the Operating Budget is submitted for review and approval by senior management. UGI Gas's direct expenses are then consolidated with allocated expenses from shared administrative and general functions within UGI and from other affiliated companies providing shared services to UGI Gas to develop the budgeted Statement of Operations. Allocated expenses in the Statement of Operations include functions such as accounting, rates, gas supply, human resources, information systems, payroll, and remittance processing, which are performed in accordance with PUC-approved methods of allocation and affiliated interest arrangements or agreements.

The final Operating Budget is then submitted to UGI's President and Board of Directors for their review and approval. Each element of the UGI Gas Operating Budget is formulated by personnel with responsibilities specific to each aspect of the operation. The first and primary use of the Operating Budget is as a working tool for the management and planning of the business.

Operating personnel in each functional area prepare a detailed list of capital projects. Each project is identified, described, and justified along with a breakdown of the costs associated with it. These projects are presented to senior management, which reviews them in terms of priority, capital availability, and strategic alignment with the operating budget. After due consideration, the Capital Budget is set and presented, along with the Operating Budget, to senior management in a series of review meetings. Additional information concerning the factors considered in establishing the UGI Gas Capital Budget is provided in the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 5).

The UGI Gas Capital Budget is prepared in conjunction with the Operating Budget. With the passage of Act 11 of 2012, UGI Gas has also instituted a process for establishing an Operating Budget and Capital Budget for an additional fiscal year in the future, *i.e.*, the FPFTY. This process is the same as outlined above; however, the starting point for the additional year is the FTY budget. The FTY revenue budget is based on normalized weather conditions, per customer usage trends, and projections concerning growth in numbers of customers. Similarly, FTY budget expense amounts are adjusted for salary and personnel increases, known program changes, and expense needs. For the capital budget, known capital projects are included based on the process described above, and additional assumptions are made for emergent new business opportunities and other operating and capital expenditures based on past experience and current trends, as described in Ms. Schappell's testimony (UGI Gas Statement No. 5).

Q. Please explain how expenses from affiliated companies are treated to develop the budgeted Statement of Operations.

A. UGI Gas incurs costs for services provided by UGI Corp., and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. UGI also allocates or assigns costs between UGI Electric and UGI Gas. All costs that can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs that cannot be directly associated with the operation of an individual operating unit are allocated to the various companies benefiting from the service. Allocations are made by using a methodology applicable to the cost (*e.g.*, budgeted time allocations, number of employees, etc.) or, if no one methodology is specific to the cost, by using a formula referred to as the Modified Wisconsin Formula ("MWF") or another reasonable allocation methodology. The MWF or other allocation methodology achieve an equitable distribution of common expenses based on the relative activity and size of each operating unit to the total of all operating units, which benefit from the respective activities. Activity is measured by total revenues and total operating expenses and size is measured by tangible net assets employed (excluding acquisition goodwill).

Q. How is the budget information used to support UGI Gas's requested revenue increase?

A. This budget information is the starting point for UGI Gas's claims and is adjusted as appropriate to reflect new information gained since the completion of the budgeting process and through application of other appropriate ratemaking principles.

VI. REVENUE REQUIREMENT FOR THE FULLY PROJECTED FUTURE TEST YEAR

Q. How is your discussion of UGI Gas's FPFTY revenue requirement presentation organized?

A. In Section VI.A, I present a summary of UGI Gas's FPFTY revenue requirement. In Section VI.B., I discuss UGI Gas's proposed rate base. In Section VI.C., I explain the determination of UGI Gas's revenues and operating expenses, depreciation, taxes other than income taxes, income taxes, and the gross revenue conversion factor.

A. FPFTY REVENUE REQUIREMENT SUMMARY

Q. How were the *pro forma* revenue increase and revenues at proposed rates established?

A. This calculation is shown at a summary level on Schedule A-1, column 4, of UGI Gas Exhibit A (Fully Projected). Lines 1-9 summarize the *pro forma* measure of value (rate base). Lines 10-19 show *pro forma* revenues at present rates, *pro forma* expenses, taxes at present rates, *pro forma* net operating income at present rates, and the calculated rate of return at present rates. Lines 20-23 show the increase in net operating income required to permit UGI Gas to earn its required overall rate of return of 7.96%. Application of the Gross Revenue Conversion Factor ("GRCF") on line 24 establishes the revenue increase shown on line 25 needed to generate that net operating income. Column 4 of Schedule A-1 shows the level of the revenue increase and the increase in expenses associated with the revenue increase. Column 5 of Schedule A-1 shows the revenue, expenses, and rate base at proposed rates, as well as the resulting rate of return of 7.96%.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $82.7 million. This represents the difference between the *pro forma* FPFTY revenue requirement of $1.145 billion and the annual level of operating revenues of $1.063 billion under existing rates. These figures are shown on line 13 of Schedule A-1 of UGI Gas Exhibit A (Fully Projected).

B. FPFTY RATE BASE

Q. With reference to UGI Gas Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Gas's rate base presentation is shown in UGI Gas Exhibit A (Fully Projected), Schedule C-1. Schedule C-1 summarizes the UGI Gas rate base values for the FPFTY. Column 1 indicates the schedule upon which the calculation of each of the rate base elements is found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Gas's total FPFTY rate base claim is $3.169 billion. Please see the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3) for a discussion of the rate base components.

C. FPFTY REVENUES AND EXPENSES

Q. How were revenues at present rates determined?

A. Revenues at present rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, the roll-in of revenues from the Distribution System Improvement Charge ("DSIC"), and other *pro forma* annualizing and normalizing ratemaking adjustments. The net effect of these adjustments is shown in UGI Gas Exhibit A (Fully Projected), Schedule D-5, and is discussed in the direct testimony of Sherry A. Epler (UGI Gas Statement No. 8).

Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to operating expense claims.

A. UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2023. Section D of UGI Gas Exhibit A (Fully Projected) presents UGI Gas's claims and necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to expense are summarized in Schedules D-3 and D-6 through D-34. These expense adjustments are used, in part, to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule D-1.

UGI Gas Exhibits A (Historic) and A (Future) follow the format of UGI Gas Exhibit A (Fully Projected) but reflect data for the appropriate test years ending September 30, 2021 and 2022, respectively. This information is provided in accordance with the Commission's filing requirements and provides a basis for comparing UGI Gas's FPFTY claims with prior results.

1. Summary

Q. Please describe Schedule D-1 of UGI Gas Exhibit A (Fully Projected).

A. Schedule D-1 presents a summary income statement that includes UGI Gas's claimed gas revenues, expenses, and taxes at present and proposed rate levels. The direct testimony of Sherry A. Epler (UGI Gas Statement No. 8) addresses the presentation of *pro forma* revenues, adjustments thereto, and the supporting schedules. Schedule D-1 also shows the proposed revenue increase of $82.7 million on line 4 in column 2.

Q. What is the level of net income at proposed rates?

A. As shown on column 3, line 21, this amount is $252.255 million. This represents a $57.867 million increase from the level under current rates ($194.387 million), as shown on line 21 in column 1 of Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows the development of the various line items found on Schedule D-1. Column 2 contains the Company's budgeted level of revenues and expenses for the 12-month period ending September 30, 2023. Column 3 shows adjustments to the column 2 figures, where applicable, to reflect various annualization and/or normalization adjustments. Column 4 is the sum of columns 2-3. The amount of the revenue increase and related expenses are shown in column 5 with the resulting revenues and expenses at proposed rates shown in column 6.

Q. Are there schedules showing the derivation of the adjustments shown in Schedule D-2, column 3?

A. Yes. The derivation of the various column 3 revenue adjustments is included in UGI Gas Exhibit A (Fully Projected) in summary fashion on Schedule D-3, page 1, lines 1-13, and then listed by individual adjustment on Schedule D-5. Customer charge and distribution rate revenue adjustments for each customer class are shown on lines 1-5 of Schedule D-3. Gas cost revenue adjustments for each customer class are shown on lines 6-10 and details of other revenue adjustments are shown on lines 11-13 of Schedule D-3. Details for each revenue adjustment are shown in Schedules D-5 (including supporting Schedule D-5A) and are discussed in the direct testimony of witness Sherry A. Epler (UGI Gas Statement No. 8). Regarding *pro forma* expenses, the derivation of the various adjustments is summarized individually on pages 1-2 of Schedule D-3, lines 16-55. The details for these adjustments are found in Schedules D-6 through D-31.

2. Operating Expense

Q. How were the claimed operating expenses for the FPFTY determined?

A. *Pro forma* FPFTY expenses are based on the budgeted level of expenses as a starting point. The budgeted data, by FERC account, was then adjusted in accordance with Commission precedent and generally accepted ratemaking principles to reflect a normal, ongoing level of operations. Schedules supporting those adjustments are found in UGI Gas Exhibit A (Fully Projected), Section D.

Q. Does UGI Gas budget its operating expenses by FERC account?

A. Yes, it does. UGI Gas budgets its operating expenses both by FERC account and by cost element, such as payroll, employee benefits, rent, etc. UGI Gas uses historic data as a basis for the distribution of expenses to each FERC account. This is shown in Schedule B-4 and is the starting point to determine the FPFTY adjusted operating expenses shown on Schedule D-3.

Q. Were each of the *pro forma* adjustments reflected on Schedule D-3 also charged to an appropriate FERC account?

A. Yes. Each *pro forma* adjustment was calculated based on the appropriate cost element and then distributed to FERC accounts directly or by using the ratio used to distribute the budgeted cost for that element.

Q. Does Schedule D-3 depict the *pro forma* expense adjustments using FERC accounts?

A. Yes. These *pro forma* expense adjustments are presented by major FERC account category. These adjustments are also shown in the Section D summary schedules.

Q. Schedule D-3 to UGI Gas Exhibit A (Fully Projected) shows an adjustment to Gas Costs in column 4. Please discuss this adjustment.

A. The detail for this adjustment is shown in Schedule D-6. This adjustment is designed to increase purchased gas cost expense by the same amount of the gas cost revenue adjustment recommended in the direct testimony of Sherry A. Epler (UGI Gas Statement No. 8) and as shown on Schedule D-5, column 4, lines 7-12. UGI Gas recovers its purchased gas costs on a dollar-for-dollar basis with no profit through an automatic adjustment clause mechanism pursuant to Section 1307(f) of the Public Utility Code. Therefore, the increase in purchased gas costs of $38.877 million equals the increase in gas cost revenue as recommended by Ms. Epler. Thus, the purchased gas cost expense has no effect on net operating income.

Q. Please discuss the revenue adjustment, i.e., operations and maintenance fees, for a renewable natural gas ("RNG") interconnection on Schedule D-5B.

A. Schedule D-5B, Column 3, shows a $348,000 increase to revenue, which represents an annual payment for operating and maintaining the RNG interconnection with Archaea Energy's Keystone Landfill in Dunmore, Pennsylvania that was not included in the budget. The interconnect is necessary for the Company to receive converted biogas (i.e., RNG) generated from Archaea's facility. These payments began in December 2021.

Q. Please discuss the Salaries and Wages adjustment shown on Schedule D-7 in the amount of $1.186 million.

A. Schedule D-7, Column 4, shows a $1.186 million increase to budgeted salaries and wages to reflect end of FPFTY operating conditions. This adjustment annualizes payroll expense and is distributed among the various cost accounts. Page 2 of Schedule D-7 shows the development of this adjustment.

Q. Please describe the annualization adjustment.

A. This adjustment annualizes the effect of wage increases for unionized, exempt, and non-exempt employees that will take place during the FPFTY. Schedule D-7, page 2, line 2 reflects the increased percentages for each classification of employee. Lines 3 through 5 indicate the percentage of the year for which the salary and wage increases are not reflected in the budget.

Q. How did you determine the split of the budgeted salaries among the various employee classifications shown on Schedule D-7?

A. The split of the budgeted salaries among the various classifications shown on Schedule D-7, page 1, was determined using the allocations of labor and headcount for Operating and Maintenance expense in the budget. These employee groupings are the same groupings utilized in developing the labor budget. These categories were used in UGI Gas's budgeting process for the operating expense portion of salaries and wages.

Q. Are there other salary and wage adjustments shown on Schedule D-7?

A. Yes. Schedule D-7, Column 2 shows a total adjustment to salaries and wages in the amount of $2,385,000, which consists of three separate adjustments. The first adjustment of $1,148,000 for salary increases and $51,000 for incremental incentive bonus compensation is presented on Schedule D-9. It aligns salaries for specific positions with relevant industry pay-scales. This adjustment is discussed in more detail in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 1). The second adjustment of $643,000 on Column 2, line 4, is presented on Schedule D-17. It represents twenty (20) unbudgeted positions for field operations. These positions are needed for succession planning for field operations roles. This adjustment is discussed in more detail in the direct testimony of Timothy J. Angstadt (UGI Gas Statement No. 9). The final adjustment for $543,000 in Column 2, line 8, is also presented on Schedule D-9 (at Column 1, lines 6 plus 8). It represents the addition of five (5) new positions to implement Transportation Security Administration ("TSA") Security Directives 2021#1 and 2021#2. This adjustment is discussed in more detail in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 1).

Q. What adjustments are shown on Schedule D-8?

A. Schedule D-8 represents an adjustment in the amount of $3.310 million for environmental remediation expense. The adjustments are described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. Please describe the salary and wage adjustments shown in Schedule D-9.

A. The salary and wage adjustments are discussed in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 1). The first adjustment, which is shown on Schedule D-9, Column 1, line 4, relates to budget modifications the Company is making as a result of a recent compensation benchmarking review that focused on how UGI Gas may continue to remain productive in an increasingly competitive labor market. The $1.32 million adjustment on Schedule D-9, Column 2, line 5, reflects an incremental increase in salary, bonus, and benefit costs. The Company calculated the Benefits component (Schedule D-9, Column 1, line 4) by applying 10% to the Compensation Benchmark Adjustment Subtotal (*i.e.*, 10% x $1,199,000 = $120,000).

The second adjustment, which is shown on Schedule D-9, Column 1, line 7, in the amount of $49,000, is related to the TSA Security Directives discussed above. In addition to the $543,000 adjustment for the five salaried positions needed to comply with the new TSA Directions shown above (Schedule D-9, Column 1, lines 6 and 8), the Company is making another adjustment to account for the employee benefits associated with the five (5) new positions (in the amount of $49,000), which is shown on Schedule D-9, line 7. These additional benefit expenses were calculated using an average per employee benefit cost of $9,702 per each of the 5 positions. Employee benefits were not included in the calculation of salaries associated with these employees in Schedule D-7.

Q. Please discuss Schedule D-10, which shows an adjustment for Rate Case Expense.

A. Lines 1 through 3 show the rate case expense that UGI Gas expects to incur in this case of $1.055 million. That amount is then normalized over a one-year period. The budgeted amount of rate case expense in the FPFTY was $1 million. The budget was increased by $55,000 as shown in Column 3, line 8 to reflect more current costs.

Q. What is the nature of the adjustments shown on Schedule D-11?

A. Schedule D-11 represents adjustments in the amount of $2.176 million for uncollectible expense. The adjustments are described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. Please explain the adjustment shown on Schedule D-12.

A. Schedule D-12 represents an adjustment in the amount of $92,000 to recover costs incurred to implement the Company's Emergency Relief Program ("ERP"), which was established in Docket No. R-2019-3015162. The adjustment is explained in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. What is the nature of the adjustment shown on Schedule D-13?

A. Schedule D-13 represents adjustments in the amount of $1.883 million for costs to comply with OSHA/Emergency Temporary Standard ("ETS") directives related to COVID-19.[3] These adjustments are explained in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

[3] OSHA, COVID–19 Vaccination and Testing; Emergency Temporary Standard, Docket No. OSHA-2021-0007 (effective November 5, 2021).

Q. Please explain the adjustment in the amount of $8.388 million shown on Schedule D-14.

A. Schedule D-14 represents an adjustment in the amount of $8.388 million for pension benefit expense. This adjustment is described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. Please discuss the *pro forma* adjustment on Schedule D-15 for Injuries and Damages.

A. Schedule D-15 represents an adjustment in the amount of ($670,000) for injuries and damages. This adjustment is described in further detail in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. Please discuss the Customer Accounts Expense Adjustment on Schedule D-15.

A. This adjustment includes a component to recover unbudgeted interest on customer deposits. Further discussion on customer deposits can be found in the direct testimony of Vivian K. Ressler (UGI Gas Statement No. 3).

Q. The Customer Accounts Expense Adjustment on Schedule D-15 shows a $972,000 cost item for Interest on Customer Deposits at line 10. Please explain.

A. The Company is required to pay interest on Customer Deposits that it holds in accordance with its tariff requirements. As this is a typical business expense, the Company has added this amount to its expense claim that is otherwise not reflected in the operations budget. It is calculated by using the average level of customer deposits anticipated for the FPFTY (*i.e.*, $21.600 million) times the required interest rate (4.50 percent) anticipated for the

FPFTY, as published by the Pennsylvania Department of Revenue and as required under the Company's tariff.

Q. Please discuss the Rent Expense Adjustment on Schedule D-15.

A. An adjustment in the amount of $565,000 recovers unbudgeted rent expense associated with the Auburn Capacity Lease Agreement approved by Secretarial Letter issued by the Commission at Docket No. G-2021-3028753 on November 22, 2021. This amount pertains to an agreement to lease additional capacity for a Rate XD customer and will be directly assigned to the customer in the Company's cost of service study. Please see the direct testimony of Christopher R. Brown (UGI Gas Statement No. 1) for additional detail on this agreement.

Q. Please discuss the *pro forma* adjustment on Schedule D-16 for Universal Service expense.

A. This adjustment normalizes the amount of Universal Services Program ("USP") expense recovered through the Company's USP Rider based on the level of the Universal Service Rider charge effective at the time of the Company's filing in this matter. The USP Rider recovers the Company's Customer Assistance Program ("CAP") Credits, Pre-Program Arrearages, third party administrator expense, LIURP expense, and administrative costs associated with its Project Share program. The Company's claim represents the ongoing normalized level of costs based on anticipated levels of CAP program participation. This adjustment increases the Company's budgeted expense by $548,000, to align the Company's current USP Rider charge. As the USP Rider is a fully reconcilable rider, the

USP adjustment assures that expenses related to the existing rider are aligned with revenues and that no impact related to USP flows through to the revenue requirement calculation. Please see the direct testimony of Ms. Epler (UGI Gas Statement No. 8) for additional discussion of the USP Rider.

Q. Please describe the adjustment on Schedule D-17.

A. The adjustment shown on Schedule D-17, Column 2, line 2, in the amount of $124,000 is for the employee benefits for the twenty (20) new positions. These additional benefit expenses were calculated using an average per employee benefit cost of $9,702. This amount was then allocated to capital expense and operations expense.

Q. Please explain the adjustment for Energy Efficiency and Conservation ("EE&C") Programs shown on Schedule D-19.

A. As with the USP Rider adjustment discussed above, this adjustment in the amount of $3.480 million aligns the amount of EE&C expense with the EE&C Rider charge (based on the level of the EE&C Rider charges effective at the time of the Company's filing in this matter). The EE&C Rider recovers the Labor and Administrative, Prescriptive Program, Retrofit Program, New Construction Program, Custom Program, Legal and Consulting, Combined Heat and Power, and other Costs associated with the Company's Energy Efficiency and Conservation Program. This adjustment increases the Company's budgeted expense to align with the Company's current EE&C charge. As the EE&C Rider is a fully reconcilable rider, the EE&C adjustment assures that expenses related to the existing rider are aligned with revenues and that no impact related to EE&C flows through to the revenue requirement calculation. Please see the direct testimony of Ms. Epler (UGI Gas Statement No. 8) for additional discussion of the EE&C Rider.

3. Depreciation Expense

Q. How was the level of depreciation expense for the FPFTY determined?

A. UGI Gas's depreciation study is set forth in UGI Gas Exhibit A (Fully Projected) and shows the determination of *pro forma* depreciation expense. This study uses the FPFTY plant in service and the applicable depreciation rates, service lives, and procedures. A summary of the budgeted depreciation expense and adjustments thereto is found in UGI Gas Exhibit A (Fully Projected), Schedule D-21, and is further explained in the direct testimony of John F. Wiedmayer (UGI Gas Statement No. 4).

Q. Please describe the depreciation expense adjustments shown on Schedule D-21.

A. UGI Gas witness Mr. Wiedmayer (UGI Gas Statement No. 4) presents the depreciation analysis that serves as the foundation of the depreciation adjustment. The adjustment for depreciation expense of $2.099 million set forth on Schedule D-21, page 2, column 3, line 64, annualizes budgeted FPFTY depreciation expense to calculate an entire year's worth of depreciation on plant in service (as of the end of the FPFTY). This schedule also shows a decrease to the net negative salvage amortization of $39,000. The total annualized depreciation expense for the FPFTY, net of costs charged to clearing accounts and net salvage amortization, is $125.537 million (as shown on Schedule D-3, page 2, column 13, line 54).

4. Taxes other than Income Taxes

Q. Please describe the taxes other than income adjustments shown on Schedule D-31.

A. Schedule D-31 contains the details for taxes other than income adjustments. The adjustments to the payroll tax expenses on lines 4-6 are calculated by multiplying the ratio of tax expense to payroll expense included in the FPFTY budget by the amount of the payroll adjustment derived in Schedule D-7. This produces an adjustment to the amount of social security, Federal Unemployment Tax ("FUTA") and State Unemployment Tax ("SUTA") expense in the amount of $298,000. The calculation of these adjustments is shown in more detail on Schedule D-32. The other components of this schedule are supported in the testimony of Nicole M. McKinney (UGI Gas Statement No. 7).

5. Income Taxes

Q. What is the purpose of Schedules D-33 and D-34?

A. These schedules show the derivation of the Company's pro forma income tax expense claim, including the normalization of the effects of accelerated tax depreciation, as discussed in the direct testimony of Nicole M. McKinney (UGI Gas Statement No. 7).

6. Gross Revenue Conversion Factor

Q. What is the purpose of Schedule D-35?

A. Schedule D-35 shows the calculation of the Gross Revenue Conversion Factor used on Schedule A-1 to calculate the level of revenues required to achieve the net operating income required to generate the rate of return supported by the direct testimony of Paul R. Moul (UGI Gas Statement No. 6). These additional revenues are required to recognize that uncollectible accounts expense vary with the level of revenue and to recognize the additional state and federal income taxes attributable to the proposed rate increase.

VII. ACT 40 REQUIREMENTS

Q. Ms. Hazenstab, are you familiar with Section 1301.1 of the Public Utility Code, which is otherwise known as Act 40 of 2016?

A. Yes, I am. The legislation, among other things, eliminated the use of consolidated tax savings adjustments for setting rates for public utilities in Pennsylvania. It requires a utility to demonstrate that it shall use at least 50 percent of what otherwise would have been the revenue requirement associated with a consolidated tax savings adjustment to support reliability or infrastructure related to the rate-base eligible capital investment and that the other 50 percent shall be used for general corporate purposes. My understanding is predicated in part on the advice of counsel.

Q. Has the Company calculated what would have been the ratemaking level of a consolidated tax savings adjustment for UGI Gas prior to the enactment of Section 1301.1 of the Public Utility Code?

A. Yes, Company witness Nicole M. McKinney presents such a calculation in her testimony (UGI Gas Statement No. 7). The Company's three-year average of consolidated taxable income was $43.735 million. Based on Ms. McKinney's calculation of the net positive taxable income of the three merged entities, the amount of consolidated tax savings adjustment applicable to UGI Gas would have been $2.553 million.

Q. Does the Company's rate base claim in this case support the conclusion that it is using at least 50 percent of that revenue requirement amount (associated with a consolidated tax savings adjustment) to support reliability or infrastructure related capital investments?

A. Yes, as included in Schedule C-2 and as discussed in the direct testimony of Ms. Schappell (UGI Gas Statement No. 5), UGI Gas's *pro forma* capital additions for reliability or infrastructure projects in the FTY is $289 million and for the FPFTY is $311 million. This expenditure level is greater than 50% of the amount of what would have been the consolidated tax savings adjustment under prior ratemaking principles.

Q. Does the Company's rate base claim in this case support the conclusion that it is using at least 50 percent of that revenue requirement amount to support general corporate purposes?

A. Yes. The Company's general corporate purpose expense will also exceed 50% of the tax benefit resulting from elimination of the consolidated tax adjustment. Indeed, the Company anticipated an operating expense budget of more than $760 million in operating expenditures to be used to render gas distribution service; 50 percent of the consolidated tax adjustment revenue requirement would equate to only $1.825 million.

Q. Is the Company's presentation in this filing consistent with the Commission's and the Commonwealth Court's treatment of PA Act 40 of 2016?

A. Yes. The Company's presentation in this filing is consistent with the Commission's determination on PA Act 40 in the UGI Electric 2018 Base Rate Proceeding at Docket No.

R-2017-2640058, and the Commonwealth Court's order affirming the Commission's order on appeal.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT TAH-1

Tracy A. Hazenstab
Principal Analyst - Rates

Work Experience:

2008 - Current	Rates Analyst – II/Sr/Principal (Progressive Positions) UGI Utilities, Inc., Denver, PA
2004 - 2008	Business Analyst PPL Gas, Lewistown, PA
2001 - 2004	Contact Center Analyst PPL Gas, Lock Haven, PA

Previous Testimony:

2014 1307(f) Proceeding:	Docket No. R-2014-2543523
2015 1307(f) Proceedings:	Docket Nos. R-2015-2480937, R-2015-2480934
2016 1307(f) Proceedings:	Docket Nos. R-2016-2543311, R-2016-2543314
2018 1307(f) Proceedings:	Docket Nos. R-2018-3001631, R-2018-3001632
2019 1307(f) Proceeding:	Docket No. R-2019-3009647
2020 1307(f) Proceeding:	Docket No. R-2020-3019680
UGI Electric EEC Petition:	Docket No. R-2019-3004144

Education:

B.A. in International Politics, Pennsylvania State University, 1996

UGI GAS STATEMENT NO. 3

VIVIAN K. RESSLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 3

Direct Testimony of
Vivian K. Ressler

Topics Addressed:	**Accounting Process and Historic Costs**
	Rate Base
	Operating Expense Adjustments
	Capital Treatment of Certain
	    Information Technology Costs
	COVID-19 Pandemic Costs
	Costs for Federal Mandates Regarding
	    COVID-19 Vaccination & Testing

Dated: January 28, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed by UGI Utilities, Inc. ("UGI") as Senior Manager Plant and Regulatory Accounting. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Gas Division ("UGI Gas" or the "Company") and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Senior Manager Plant and Regulatory Accounting?

A. I have responsibility for UGI's plant accounting and regulatory accounting processes. I lead a team of accountants responsible for maintaining complete and accurate plant accounting records, and for preparing and submitting certain regulatory filings with the PUC and the Federal Energy Regulatory Commission ("FERC"). My duties also include the coordination of these functions with UGI's Controller and Chief Financial Officer as well as financial accounting and reporting personnel at UGI Corp.

Q. Please describe your educational background and work experience.

A. My full educational background and work experience are set forth in my resume attached as UGI Gas Exhibit VKR-1.

Q. Have you testified previously before this Commission?

A. Yes. I provided testimony in the 2020 Gas Base Rate Case proceeding for UGI Gas at Docket No. R-2019-3015162 and the 2021 Electric Base Rate Case proceeding for UGI Electric at Docket No. R-2021-3023618.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas in support of the Company's rate case accounting methodology. First, I will explain UGI Gas's accounting processes, which were used to develop the actual book accounting results, which are the basis for the Company's historic test year ended September 30, 2021 ("HTY") (Part II).[1] Second, I will present the Company's claim for rate base in this proceeding using a fully projected future test year ("FPFTY") methodology. (Part III). Next, I will discuss certain operating expense adjustments (Part IV) and the Company's accounting for certain Information Technology ("IT") costs (Part V). Then, I will discuss the Company's COVID-19 Pandemic Costs (Part VI). Finally, I will address certain costs directly attributable to compliance with: (1) the Emergency Temporary Standard ("ETS") for COVID-19 vaccination and testing issued by the Occupational Safety and Health Department of Labor ("OSHA")[2]; and (2) President Biden's COVID-19 Action Plan per Executive Order 14042 (Part VII).

[1] The budgets for the future test year ending September 30, 2022 ("FTY") and the FPFTY ending September 30, 2023 are discussed in the direct testimony of Tracy A. Hazenstab (UGI Gas St. No. 2).
[2] See 86 Fed. Reg. 61,402, Docket No. OSHA-2021-0008 (Nov. 5, 2021).

Q. Ms. Ressler, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Gas Exhibit VKR-1. In addition, I am sponsoring those portions of UGI Gas Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic), which address rate base and certain adjustments to rate base and operating expenses discussed later in my testimony. I am also sponsoring those responses to the Commission's standard filing requirements as stated on the master list accompanying this filing.

II. ACCOUNTING PROCESS AND HISTORIC COSTS

Q. How are the accounting records of UGI Gas maintained?

A. The accounting records of UGI Gas are kept in accordance with generally accepted accounting principles ("GAAP") and the FERC's Uniform System of Accounts as required under the provisions of 52 Pa. Code § 59.42. The Company also maintains a continuing property records system in accordance with the requirements of 52 Pa. Code § 59.46.

Q. Are the books and records of UGI Gas subject to audit?

A. Yes. The books and records of UGI Gas are audited by its internal auditors. In addition, UGI Gas's books and records are included in Company-wide audits of UGI, performed by its external auditor, Ernst & Young, LLP. The Company's books and records are further subject to audit by the PUC.

Q. Do the continuing property records of UGI Gas reflect the original cost value of property?

A. Yes, they do. UGI Gas's plant in service, plant additions, retirements, and book adjustments have been recorded on an original cost basis in accordance with GAAP and the Uniform System of Accounts requirements.

Q. What process does UGI Gas follow to assure that property reflected in its plant accounts is in service?

A. UGI Gas's capital project managers create records that document the costs of projects and/or asset purchases. When a capital project or asset is placed into service, the project manager records the in-service date and the retirement detail for any related assets that are taken out of service. Then, the record is provided to accounting personnel. This information is transferred through accounting entries into the appropriate UGI Gas plant property accounts, subject to review by authorized individuals who approve the entries and further review by internal and external auditors.

Q How was the Company's accounting process used in preparing the Company's filing?

A. The above-described accounting process was used to prepare the principal accounting exhibits that support UGI Gas's claim in this proceeding. As discussed in the direct testimony of Company witnesses Christopher R. Brown (UGI Gas Statement No. 1) and Tracy A. Hazenstab (UGI Gas Statement No. 2), the Company's claim is based on the FPFTY. The accounting data for the FPFTY was derived from UGI Gas's operating and capital budgets for the 12 months ending September 30, 2023, as shown in UGI Gas Exhibit

A (Fully Projected). The accounting data for the future test year ("FTY") was derived from UGI Gas's operating and capital budgets for the 12 months ending September 30, 2022, as shown in UGI Gas Exhibit A (Future). The accounting data for the HTY was derived from UGI Gas's books and records for the 12 months ending September 30, 2021, as shown in UGI Gas Exhibit A (Historic).

III. FULLY PROJECTED FUTURE TEST YEAR RATE BASE

Q. With reference to UGI Gas Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Gas's rate base presentation is shown in UGI Gas Exhibit A (Fully Projected), Schedule C-1. It summarizes the UGI Gas rate base values for the FPFTY. Column 1 provides the schedule where the calculation of each of the rate base elements is found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Gas's total FPFTY rate base claim—net of deductions for accumulated depreciation, accumulated deferred income taxes and customer deposits—is $3.169 billion. Except where otherwise noted, I will describe each of the rate base elements in greater detail below.

1. Utility Plant in Service

Q. Please explain how UGI Gas determined its FPFTY rate base value for plant in service.

A. UGI Gas's claim for utility plant in service represents the sum of the closing plant balances as of September 30, 2021, and budgeted additions placed in service for the years ending September 30, 2022 and September 30, 2023, less expected FTY and FPFTY plant retirements. The direct testimony of Company witness Vicky A. Schappell (UGI Gas Statement No. 5) discusses the capital addition planning process and the basis for the additions placed in service in the FTY and FPFTY.

Q. Please describe Schedule C-2 to UGI Gas Exhibit A (Fully Projected).

A. This schedule presents UGI Gas's FPFTY claim of $5.042 billion for used and useful gas utility plant in service on page 2, column 2, line 64. That amount is reflected on line 1 of the measure of value summary on Schedule C-1. Gas utility plant enables UGI Gas to provide safe and reliable gas service to its customers.

Q. How was the gas utility plant in service amount of $5.042 billion shown on Schedule C-2, page 2, column 2, line 64 determined?

A. As noted above, this amount is based on the *pro forma* balance as of September 30, 2023. The amount includes: (1) utility plant in service as of September 30, 2021 and (2) budgeted capital expenditures expected to be placed in service for the 12-month periods ending September 30, 2022 and 2023, less expected plant retirements during the same period. UGI Gas witness Vicky A. Schappell (UGI Gas Statement No. 5) also discusses the basis for the plant additions in the FTY and FPFTY.

Q. Please describe the information included on Schedule C-2, page 3.

A. This information provides a summary of UGI Gas's *pro forma* claim for utility plant in service by category. Column 2 shows the FPFTY ending balances based on the placed in-service budget; column 3 shows the net effect of the various plant adjustments, if any; and column 4 provides the adjusted FPFTY plant in service.

Q. What information is included on Schedule C-2, pages 4 and 5?

A. Columns 2 and 3 on these pages show the gas plant in service balances for 2022 and 2023 at the FERC account level, based on the placed in service budget. Column 5 provides the ending FPFTY plant balance at the FERC account level.

Q. Where are plant in service additions shown?

A. Pages 6 and 7 of Schedule C-2 provide actual (for the HTY) and projected (for the FTY and FPFTY) plant in service additions. The Company categorizes plant in service additions by FERC account.

Q. Where are plant retirements shown?

A. Pages 8 and 9 of Schedule C-2 provide actual (for the HTY) and projected (for the FTY and FPFTY) plant retirements. Retirements for most plant accounts were projected by plant account. The Company applied the average retirement rate, as a percent of additions, for the five fiscal years 2017 through 2021, to the FPFTY and FTY plant in service additions. For certain plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. For these accounts, all units are retired when the vintage is fully amortized.

2. Accumulated Depreciation

Q. Please explain how UGI Gas determined its rate base deduction for accumulated depreciation.

A. UGI Gas started with accumulated depreciation as of September 30, 2021, added the budgeted level of depreciation expense for the FTY and FPFTY, and calculated the impact of the FTY and FPFTY plant retirements and a provision for net salvage as shown on Schedule C-3. The depreciation rates and test year expense levels are discussed in the direct testimony of John F. Wiedmayer (UGI Gas Statement No. 4), with the underlying FPFTY depreciation analysis provided in UGI Gas Exhibit A (Fully Projected).

Q. Please describe UGI Gas's accumulated depreciation claim.

A. UGI Gas's accumulated depreciation claim is shown on Schedule C-3 of UGI Gas Exhibit A (Fully Projected). This schedule presents the accumulated provision for depreciation as of September 30, 2023, distributed among the various FERC accounts. The total amount for accumulated depreciation, $1.319 billion, is summarized on page 2, column 2, line 64, of this schedule. That amount is reflected on line 2 of the measure of value summary on Schedule C-1.

Page 3 of Schedule C-3 shows the *pro forma* FPFTY level of accumulated depreciation distributed to the various plant categories. Pages 4 and 5 show the details of the accumulated depreciation by FERC account for Fiscal Years 2022 (column 2) and 2023 (column 3) based on budget plus adjustments (column 4), if any, to arrive at the FPFTY balance (column 5). Pages 6 and 7 show the cost of removal by FERC account and pages 8 and 9 show negative net salvage amortization by FERC account. Pages 10 and 11 include the salvage amounts by FERC account. These amounts are included in the FPFTY accumulated depreciation calculations. The amortization of negative net salvage was calculated using a 5-year amortization schedule in accordance with Commission precedent.

3. Cash Working Capital

Q. Please explain how UGI Gas determined its rate base value for cash working capital ("CWC").

A. CWC is the capital requirement arising from the difference between (1) the lag in the receipt of revenue for rendering service and (2) the lag in the payment of cash expenses incurred to provide that service, as shown in Schedule C-1. A detailed analysis of UGI Gas's CWC requirements is provided in Schedule C-4.

Q. Where is the CWC rate base value summarized?

A. The CWC rate base value is summarized at Schedule C-4, page 1. The various components of the working capital claim are listed on this page, along with a reference to the page where the component is further detailed within Schedule C-4.

Q. What data is shown on page 2 of Schedule C-4?

A. Page 2 summarizes the derivation of UGI Gas's revenue collection lag and overall expense payment lag. The revenue lag days of 61.18 are shown on line 1. Expense lag days include three categories of annual operating expenses: (1) payroll; (2) purchased gas costs; and (3) other expenses. The expense lag days are shown for each component on lines 3-5, which amount to 32.76 (on line 7). The net lag in the collection of revenue is 28.41 days as shown on line 8. This number is then multiplied by the average daily operating expense balance on line 9 to arrive at a base CWC amount for Operations and Maintenance ("O&M")

expense of $52.365 million on line 10. The average daily expense balance of $1.843 million shown on line 9 is determined by dividing the total *pro forma* annual operating expenses, excluding uncollectible accounts expense, of $672.711 million as shown on line 6 of column 2, by the number of days in the year, or 365. I will describe the other components of the CWC claim when I discuss the related schedules.

Q. Please describe the revenue lag calculation shown on Schedule C-4, page 3.

A. The Company's calculation for the total revenue lag days of 61.18 (line 23) consists of several steps. First, the annual revenue (line 18, column 3) is divided by the average month-end accounts receivable balances for the 13 months ended September 30, 2021 (line 17, column 2). This results in an accounts receivable turnover rate of 8.27 (line 19, column 4), which is equivalent to 44.14 lag days (line 20, column 5) (i.e., 365 divided by 8.27 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to: (1) the 1.83-day lag between the meter reading day and the day bills are sent out and recorded as revenue and accounts receivable by the Company (appearing on line 21); and (2) the 15.21-day service lag (i.e., midpoint lag factor), which is the time from the mid-point of the service period until the meter reading date (appearing on line 22). This calculation results in a total revenue lag of 61.18 days.

Q. How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the number of days in an average service month (365 days divided by 12, or 30.4 days) divided by two (i.e., 15.21 days).

Q. How are the payroll expense lag days for the CWC claim calculated?

A. This calculation is shown on page 4 of Schedule C-4, lines 1-6. The payroll amounts shown there reflect the payroll for the FPFTY, which is shown on Schedule D-7. The lag periods for union and non-union payroll are shown separately on page 4 of Schedule C-4, lines 1-2, with the same bi-weekly pay period. The lag days are calculated based on 14 days in the pay period divided by 2 (for an average) with a 5-day payroll processing time period added, resulting in a 12-day lag period.

Q. How were the lag days associated with the purchased gas costs shown on Schedule C-4, page 4, line 8 calculated?

A. This calculation is shown on page 6 of Schedule C-4 and is based on a review of gas purchases during the 12-month period of October 2020 through September 2021. The total dollar amount of gas purchased during this period was $374.258 million (on line 13, column 2). The average payment lag was calculated by dividing the total dollar days for purchased gas costs (or $14.916 billion) by the total dollar amount of gas purchased (or $374.258 million), which equals 39.85 days (on line 14). The payment lag was determined using the midpoint of the service period for each of the payments and the payment date for each, averaged over the 12-month study period. The 39.85-day lag for purchased gas costs is then brought forward to Schedule C-4, page 4, line 8 and Schedule C-4, page 2, column 3, line 4.

Q. What are dollar days, and how were they used in the CWC calculation?

A. Dollar days are the product of a payment amount multiplied by the number of days between the invoice date or service date and the date that the payment clears the Company's bank. The dollar days calculation is used to calculate a weighted average number of lag days for both purchased gas costs (Schedule C-4, page 6) and general disbursements (Schedule C-4, page 5).

Q. How were the Other O&M Expense lag days, shown on Schedule C-4, page 4, line 22, calculated?

A. The calculation is shown on page 5 of Schedule C-4. The average payment lag for all remaining expenses was derived from data over the HTY, as shown in more detail on page 5 of Schedule C-4. A summary list of all cash disbursements, including the invoice date, the amount of the disbursement, the date the payment was made, and the type of disbursement (for capital, commodity or expense), during each of these months was used. As shown on page 5, lines 1-24, columns 1 and 2, each month's listing contained numerous cash disbursements. Once the raw payment data was assembled, the dollar days for expense purchases were determined by multiplying the amount of the disbursement by either (i) the number of days from invoice date until bank clearance for wire and Automated Clearing House ("ACH") payments, or (ii) the number of days from the invoice date until check date, plus seven days (representing mail lag) for payments made by check. Disbursements were eliminated if they were included in another calculation (*e.g.*, gas purchases) or were paid for capital items. After these adjustments, the average of the expense lag days for each month shown on Schedule C-4, page 5, column 4, line 25, resulted in a payment lag for general disbursements of 27.08 days. The 27.08- day lag for general disbursements is then brought forward to Schedule C-4, page 4, line 22 and Schedule C-4, page 2, column 3, line 5.

Q. Please explain how the interest payment amount included on line 2 of Schedule C-4, page 1 was determined.

A. The calculation of this amount is shown on Schedule C-4, page 7. This calculation measures the lag associated with the payment of interest on outstanding debt. The *pro forma* annual interest expense shown on line 4 is divided by 365 to obtain the daily interest expense of $155,000 shown on page 7, line 5. That amount is then multiplied by the net payment lag, resulting in a reduction to the working capital allowance of $4.667 million as shown on page 7, line 9 of Schedule C-4. This amount is then included on page 1, line 2 of Schedule C-4.

Q. How was the tax payment lag for the working capital requirement, shown on line 3 of Schedule C-4, page 1, determined?

A. This calculation is shown on page 8 of Schedule C-4. Separate tax payment lag calculations (for working capital) are made for federal income tax, state income tax, PA Property Tax and Public Utility Realty Tax Act ("PURTA") taxes. Each of these calculations is based on anticipated FPFTY tax payments and an April 1 mid-point of annual service. The result for each of these components is shown and summed in column 10 to derive the net working capital allowance for tax payments of $4.402 million.

Q. How was the working capital allowance for prepaid expenses, shown on line 4 of Schedule C-4, page 1, derived?

A. That amount is calculated on page 9 of Schedule C-4 and represents the 13-month average of actual pre-paid amounts for each month ended from September 2020 through September 2021. The 13-month average of total actual pre-paid amounts during that period is $10.047 million.

Q. What is the total amount of the Company's CWC claim?

A. UGI Gas's claim for CWC is $62.148 million. This amount is shown on Schedule C-4, page 1, line 5; Schedule C-1, line 4; and on Schedule A-1, line 4.

4. Gas Storage Inventory

Q. Please explain how the rate base value for gas storage inventory was determined.

A. Gas storage inventory represents gas volumes stored in facilities or in storage fields owned by interstate pipeline or storage companies with whom UGI Gas contracts for capacity. As is typical for most natural gas distribution systems, UGI Gas purchases storage gas throughout the year for use primarily during the winter heating season. Specifically, the Company pays its gas storage bills on a monthly basis once the gas is procured in the same way that its pays for gas procured from other sources. Storage inventory is a physical asset that is included in the Company's rate base claim in the same manner as materials and supplies inventory. UGI Gas's claim for gas storage inventory is based on a 13-month average book value for the period ending September 2021 as shown on Schedule C-5. The average monthly gas inventory balance for the FPFTY is $17.813 million, as shown on

Schedule C-5, line 16. This amount is also used in Schedule C-1, line 5 and Schedule A-1, line 5.

5. Accumulated Deferred Income Taxes

Q. Please explain how the rate base value for Accumulated Deferred Income Taxes ("ADIT"), including Excess Deferred Federal Income Taxes ("EDFIT"), was calculated.

A. The Company's determination of its rate base value for ADIT, including EDFIT, is shown on Schedule C-6 and is discussed in the direct testimony of Nicole M. McKinney (UGI Gas Statement No. 7).

6. Customer Deposits

Q. Please explain how the Company calculated the rate base value for customer deposits.

A. Customer deposits offset the need for UGI Gas to provide capital. UGI Gas's claimed offset for customer deposits is based on the average customer deposit balance for the 13-month period ending September 2021, as shown on Schedule C-7.

Q. What is the rate base offset for customer deposits?

A. The customer deposit offset is $21.600 million, as shown on Schedule C-7, line 16, Schedule C-1, line 7, and on Schedule A-1, line 7.

7. Materials and Supplies Inventory

Q. What is the rate base claim for materials and supplies inventory?

A. UGI Gas maintains various materials and supplies in inventory for use in its operations. The Company's claim for materials and supplies inventory is $15.707 million, as shown on Schedule C-8, line 16, Schedule C-1, line 8, and on Schedule A-1, line 8. This amount is based on the average inventory for the 13-month period ending September 30, 2021, as shown on Schedule C-8.

IV. OPERATING EXPENSE ADJUSTMENTS

Q. Please describe how the Company's claimed operating expenses were determined.

A. As discussed in the direct testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2), the *pro forma* FPFTY expenses were based on the budgeted level of expenses as a starting point. This budgeted level of expenses was then adjusted to comply with Commission precedent and generally accepted ratemaking principles to reflect a normal, ongoing level of operations. The supporting schedules for those adjustments are found in UGI Gas Exhibit A (Fully Projected), Section D. Below, I will discuss the specific operating adjustments that I am sponsoring, as contained in UGI Gas Exhibit A (Fully Projected), Section D.

1. Environmental Remediation Expenses

Q. What adjustments are shown on Schedule D-8?

A. Consistent with the methodology the Company has used in past rate cases, the adjustments shown on Schedule D-8 are designed to reconcile past Environmental Remediation expense rate recoveries with actual incurred costs and to recover a projected annual level of

Environmental Remediation expense. These costs are incurred in connection with UGI Gas's obligations under a Consent Order Agreement ("COA") with the Pennsylvania Department of Environmental Protection ("DEP").[3] The Company's remediation activities under the COA are discussed in the direct testimony of Timothy J. Angstadt (UGI Gas Statement No. 9).

Q. Please describe the first Environmental Remediation expense adjustment shown on Schedule D-8.

A. The adjustment (on lines 1 – 6 of Schedule D-8) is intended to provide the Company with normalized ratemaking recovery of ongoing annual cash expenditures primarily to remediate former manufactured gas plant ("MGP") sites in accordance with the COA. Because the amount budgeted is the amount UGI Gas recovered in the most recent previous base rate case, it does not properly reflect the amount that the Company is likely to incur during the FPFTY. Therefore, as in past cases, the Company has chosen to normalize the expenditure based on its recent actual experience.

The average of the last three years of cash expenditures for remediation expenses under the COA is $5.171 million and represents the amount that the Company anticipates that it will spend in the FPFTY under the COA. The difference between this annual amount ($5.171 million) and the amount budgeted by the Company ($4.188 million), or $0.983 million, is the first adjustment.

[3] Effective October 1, 2020, DEP consolidated the Company's prior three COAs (which aligned with the Company's former rate districts) into one COA that covers the entire UGI Gas service territory.

Q. Is the Company making an Environmental Remediation expense adjustment related to under-recovered MGP expenses for Fiscal Year 2019 and prior periods?

A. No. Lines 7 – 12 of Schedule D-8 show that the Company's annual amortization of the balance of under-recovered MGP expenses for periods prior to September 30, 2019, approved in the 2020 Base Rate Case, matches the amount budgeted for that time. In the 2020 Base Rate Case, the Company was authorized to amortize $8.103 million of under-recovered MGP expenses over a 5-year period, or $1.621 million per year for under-recovered MGP expenses for periods prior to September 30, 2018. Also in the 2020 Base Rate Case, the Company was authorized to amortize an additional $1.219 million over a 5-year period, or $0.24 million per year for under-recovered MGP expenses for Fiscal Year 2019. The Company budgeted this same annual amount ($1.865 million) for expense purposes. As such, no adjustment is needed for this item.

Q. Please describe the final Environmental Remediation expense adjustment shown on Schedule D-8, lines 13 – 17 for Fiscal Years 2020 and 2021.

A. The adjustment (on lines 13 – 17 of Schedule D-8) shows the under-recovery of the Company's MGP remediation expense incurred since the last rate case by comparing the actual Fiscal Year 2020 and 2021 remediation costs with the normalized level authorized in the 2019 and 2020 Base Rate Cases, respectively. The unrecovered expenditures of $2.327 million (line 15) will be recovered over a one-year amortization period through Fiscal Year 2023.

Q. What ratemaking amount is used to determine the future years' costs subject to reconciliation in the next rate case?

A. That amount is the annual amount derived from the first adjustment on Schedule D-8, or $5.171 million, which is the normalized amount indicative of UGI Gas's experience over the past three years. Any future years' variance of actual annual expenditures from that figure will be credited to customers (in the case of an overcollection) or recovered from customers (in the case of an undercollection) in the Company's next base rate case.

2. Uncollectible Accounts Expense

Q. Please explain the two adjustments being shown on Schedule D-11 for Uncollectible Accounts Expense.

A. The first adjustment, $2.026 million, adjusts budgeted uncollectible accounts expense to reflect a three-year average rate of uncollectible accounts expense for Fiscal Years 2019, 2020, and 2021. The baseline amounts for Fiscal Years 2020 and 2021 include $0.607 million and $0.896 million, respectively, of amounts recorded as a regulatory asset (as further discussed under the second adjustment in Schedule D-11 below). This ratio is used to adjust the amount of uncollectible expense in the budget to conform to the three-year average uncollectible rate. The resulting 1.647 percent ratio shown on line 4, column 5, is applied on line 7 to the *pro forma* revenues at present rates to calculate the *pro forma* uncollectible accounts expense of $17.426 million shown on line 7, column 4. This results in an increase in the level of uncollectible accounts expense for the FPFTY from the budgeted amount of $15.400 million shown on line 5. The 1.647 uncollectible ratio is then applied to determine the level of uncollectible accounts expense at *pro forma* proposed rates through the gross revenue conversion factor, as shown in column 3, line 2 of Schedule D-35.

The second adjustment in Schedule D-11 represents the amortization of the regulatory asset balance of $1.503 million for COVID-19 Pandemic Costs over a 10-year amortization period (in accordance with Ordering Paragraph 29 in the Commission's Order entered October 8, 2020 at Docket No. R-2019-3015162). According to Ordering Paragraph 30, COVID-19 Pandemic Costs include "annual uncollectible accounts expense in excess of $12.81 million beginning with the fiscal year period ending September 30, 2020 and continuing for annual periods thereafter until the effective date of the Company's next base rate filing . . . ." The same Ordering Paragraph indicates that such COVID-19 Pandemic Costs shall be eligible for recovery for ratemaking purposes.

For the Fiscal Years ended September 30, 2020 and September 30, 2021, UGI Gas had uncollectible costs of $13.417 million and $13.706 million, respectively. For these two years, the combined excess of uncollectible expense incurred over the established threshold of $12.810 million per year was $1.503 million, which was established as a regulatory asset and is being amortized over a 10-year period effective at the beginning of the FPFTY. This results in an increase in the level of uncollectible accounts expense for the FPFTY of $150,000, as shown on line 11. The total increase (above the budgeted amount) in the uncollectible accounts expense for the FPFTY is $2.176 million, as shown on line 12.

3. Emergency Relief Program ("ERP") Adjustment

Q. Please describe the adjustment shown on Schedule D-12.

A. The adjustment shown on Schedule D-12 reflects recovery of costs associated with the temporary Emergency Relief Program ("ERP"). The Company established the ERP in response to the COVID-19 Pandemic to aid customers who were unable to fully pay their utility bills. The costs of the program include implementation expenses and direct bill credits. The ERP was approved within the settlement agreement to the Company's 2020 Gas Base Rate Case at Docket No. R-2019-3015162. The Company's costs of $0.922 million associated with the program were accumulated within a regulatory asset. The Company is proposing to amortize these costs over a 10-year period, in accordance with Ordering Paragraph 29 in the Commission's Order approving the settlement in the Company's 2020 Gas Base Rate Case.

4. Benefits Expense Adjustment

Q. Please describe the adjustment shown on Schedule D-14.

A. The adjustment shown on Schedule D-14 reflects an adjustment from budgeted pension expense to reflect cash to be contributed to the plan in the FPFTY. The Company's budget reflects pension expense based on GAAP requirements to reflect service and non-service costs based on assumptions. However, consistent with prior ratemaking practices, the Company claims pension costs within its rates on a cash basis. The adjustment is calculated as the total cash contributions (per the Company's most recent actuarial report), reduced to reflect only the portion attributable to UGI Gas, and then further reduced to reflect the portion of pension that is capitalizable. This cash pension expense of $5.501 million (line 5) is compared to the budgeted pension income of ($2.887) million (line 1), also calculated for UGI Gas only and net of the capitalizable portion, resulting in an adjustment of $8.388 million (line 6).

5. Injuries and Damages Adjustment

Q. Please discuss the adjustment for Injuries and Damages shown on Schedule D-15.

A. The amount of expense incurred for injuries and damages in any one year can vary based on the quantity and severity of the claims. The Company bases its claim for injuries and damages on a normalized amount. This is accomplished by making an adjustment on this schedule for the difference between the normalized amount and the budgeted amount. The three-year average of injuries and damages expenses of $1.353 million is calculated on lines 1 – 4 of Schedule D-15. The budgeted amount for injuries and damages, $2.023 million, is shown on line 5. The difference between these amounts, $0.670 million, was used to reduce budgeted injuries and damages expense by $0.670 million, as shown on line 6, to reflect the normalized expense.

V. CAPITAL TREATMENT OF CERTAIN INFORMATION TECHNOLOGY COSTS

Q. What is the Company's policy for capital treatment of certain information technology ("IT") costs?

A. Since 2016, UGI (including UGI Gas and UGI Electric) has received authorization to capitalize certain IT costs associated with software implementation projects within various base rate proceedings. These IT costs consist of internal labor, external consulting expenses, and other expenses related to the preparation of the vendor and system integrator requests for proposals. IT costs also include current-state assessments, reengineering business processes to adapt to the new system, data conversion, cleansing and migration (including field verification and digitization of asset attributes required for accurate data and facility capture), and pre-implementation training costs. Additionally, the Company capitalizes the above-mentioned cost items for cloud computing software implementation projects. Further, beginning in 2019, the Company began capitalizing Hypercare costs associated with large software implementation projects. Hypercare is a term for post-implementation support following the deployment of an IT project to ensure that the newly implemented system operates as planned.

Q. Is the Company planning to continue with similar methods of IT costs capitalization in this proceeding?

A. Yes. The Company continues to capitalize such costs in line with the authorizations received previously, and all such costs which are claimed in the current case are included within the Company's budgeted capital as laid out in Exhibit A (Future) and Exhibit A (Fully Projected).

VI. COVID-19 PANDEMIC COSTS

Q. Has the Company incurred COVID-19 Pandemic Costs, as defined in Ordering Paragraphs 29 and 30 of the Commission's Order pertaining to UGI Gas's 2020 Gas Base Rate Case at Docket No. R-2019-3015162?

A. Yes. However, the Company reviewed qualifying COVID-19 Pandemic Costs and determined that no such costs should be claimed in this rate case, except for the annual uncollectible accounts expense in excess of $12.81 million, which is included on Schedule

D-11, and the costs of the Emergency Relief Program, which are included on Schedule D-12.

VII. COSTS FOR FEDERAL MANDATES REGARDING COVID-19 VACCINATION & TESTING

Q. Is the Company seeking recovery of certain new and incremental costs directly attributable to businesses in complying with recently issued Federal requirements for COVID-19 vaccinations and testing?

A. The Company is prepared to comply with President Biden's COVID-19 Action Plan and the Department of Labor's OSHA Emergency Temporary Standard ("ETS") requirements relating to vaccination and testing mandates (collectively referred to herein as "Federal Mandates"). Under the Federal Mandates, the Company would be required to track and verify the vaccination status of its employees and contractors, and, for those who are unvaccinated, collect proof of weekly testing. The associated costs to comply with the Federal Mandates include, but are not limited to: (1) costs for a subscription to software to track vaccination status; (2) costs for performing required COVID-19 testing; (3) costs for legal assistance in interpreting and applying the Federal Mandates; and (4) costs for drafting the Company's corresponding policies and communicating such to its employees and contractors.

Q. Has the Company included these costs within its claim?

A. Yes. Because of the timing of the preparation of the Company's budget and ongoing legal challenges to the Federal Mandates, costs of compliance with the Federal Mandates were not included in the budget for the FTY or FPFTY. Therefore, the Company has included these costs as an adjustment to its Operating Expenses within Schedule D-13 of UGI Gas Exhibit A (Fully Projected). The ongoing annual costs of $1.692 million, which consist of a subscription to software to track vaccination status and the cost to perform required COVID-19 testing, are added to the budget. The one-time costs of $0.191 million are aggregated and proposed to be recovered over a one-year amortization period, also within Schedule D-13. The total budget adjustment for these costs is $1.883 million, as shown at Schedule D-13, line 6. While there remains uncertainty concerning the Federal Mandates' vaccination and testing requirements due to a recent decision by the U.S. Supreme Court,[4] UGI Gas believes it is appropriate to include a cost associated with vaccination and testing mandates in its revenue requirement to ensure future cost recovery in the event such mandates or similar mandates become law. Depending on the ultimate outcome of the Federal Mandates, UGI Gas can reassess to determine whether this figure should be further adjusted or if a regulatory asset should be created.

Q. Does the Company anticipate any additional costs associated with the Federal Mandates?

A. Yes. The Company believes that its contractors who perform much of its maintenance and construction work would be required to comply with the Federal Mandates due to their association with the Company. The Company expects that the contractors would also pass along their costs of complying with the Federal Mandates to the Company in the form of increased rates for performing construction and maintenance work on the Company's

[4] *See Nat'l Fed'n of Indep. Bus. v. Dep't of Labor*, 2022 U.S. LEXIS 496 (U.S. 2022).

utility system. However, because the Company is unable to specifically quantify these costs, they have not been included in the claim.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT VKR-1

Vivian K. Ressler

Sr. Manager – Plant and Regulatory Accounting

Work Experience

December 2021 - Current	Sr. Manager – Plant & Regulatory Accounting UGI Utilities, Inc. – Denver, PA
Feb. 2020 – December 2021	Sr. Manager – SOX, Plant Accounting & Accounts Payable UGI Utilities, Inc. – Denver, PA
June 2018 – Feb. 2020	Manager – Technical Accounting & Controls UGI Utilities, Inc. – Denver, PA
May 2014 – May 2018	Departmental Vice President – Corporate Accounting The Bon-Ton Stores, Inc. – York, PA
May 2012 – May 2014	Supervisor – Attest Services Trout, Ebersole & Groff, LLP – Lancaster, PA
Nov. 2007 – May 2012	Sr. Manager – Corporate Accounting & Tax BI-LO, LLC – Greenville, SC
Sept. 1998 – Oct. 2007	Staff Accountant through Sr. Manager – Audit Services Deloitte & Touche, LLP – Greenville, SC

Previous Testimony before the Pennsylvania Public Utility Commission

UGI Gas Base Rate Case	Docket No. R-2019-3015162
UGI Electric Base Rate Case	Docket No. R-2021-3023618

Education & Professional Certification

B. S. in Accounting – Bob Jones University, Greenville, SC

Certified Public Accountant – Commonwealth of Pennsylvania

UGI GAS STATEMENT NO. 4

JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 4

Direct Testimony of
John F. Wiedmayer, C.D.P.

Topics Addressed: **Depreciation and Net Salvage**

Date: January 28, 2022

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DIRECT TESTIMONY OF

JOHN F. WIEDMAYER

DOCKET NO. R-2021-3030218

I. INTRODUCTION

Q. Please state your name and address.

A. My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

Q. Are you associated with any firm and in what capacity?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") as Project Manager, Depreciation and Valuation Studies.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since I graduated from college in June 1986.

Q. What is your educational background?

A. I have an AB degree in Engineering from Lafayette College and a Master of Business Administration from the Pennsylvania State University.

Q. Do you belong to any professional societies?

A. Yes. I am a member of the National and Pennsylvania Societies of Professional Engineers and the Society of Depreciation Professionals ("SDP"). In 2005, I served as President of the SDP and was a member of the SDP's Executive Board for the years 2003 through 2007.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The SDP has established national standards for depreciation professionals. The SDP administers an examination to become certified in this field. I passed the certification exam in September 1997 and have fulfilled the requirements necessary to remain a Certified Depreciation Professional.

Q. Please outline your experience in the field of depreciation.

A. I have over 35 years of depreciation experience, which includes expert testimony in numerous cases before 14 regulatory commissions, including the Pennsylvania Public Utility Commission ("PUC" or "Commission").

In June 1986, I was employed by Gannett Fleming as a Depreciation Engineer. I held that position from June 1986 through December 1995. In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In August 2004, I was promoted to my present position as Project Manager of Depreciation Studies. I am responsible for conducting depreciation and valuation studies, including the preparation of testimony, exhibits, and responses to data requests for submission to the appropriate regulatory bodies. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration, and supporting such rates before regulatory bodies.

During the course of my employment with Gannett Fleming, I have assisted in the preparation of numerous depreciation studies for utility companies across various industries. I assisted in the preparation of depreciation studies for the following telephone companies: Alberta Government Telephone, Commonwealth Telephone Company, Telus, United Telephone Company of New Jersey, and United Telephone of Pennsylvania. I assisted in the preparation of depreciation studies for the following companies in the railroad industry: CSX Transportation, Union Pacific Railroad, Burlington Northern Railroad, Burlington Northern Santa Fe Railway, Amtrak, Kansas City Southern Railroad, Norfolk & Western, Southern Railway, and Norfolk Southern Corporation.

I assisted in the preparation of depreciation studies for the following organizations in the electric industry: AmerenUE, Arizona Public Service Company, UGI Utilities, Inc. - Electric Division ("UGI Electric"), Penelec, Metropolitan Edison, the City of Red Deer, Nova Scotia Power, Newfoundland Power, Owen Electric Cooperative, Bangor Hydro Electric Company, Maine Public Service Company, Michigan Electric Transmission Company, PECO, Jackson Electric Cooperative Corporation, Houston Lighting and Power, TXU, Maritime Electric, Nolin Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, and the City of Calgary - Electric System.

I assisted in the preparation of depreciation studies for the following gas companies: BGE, PECO, UGI Utilities, Inc. – Gas Division, North Penn Gas, PFG Gas, UGI Central Penn Gas, Inc., Equitable Gas, Centra Gas Alberta, Questar Gas, Orange and Rockland, Con Edison, Dominion East Ohio, AmerenUE, AmerenCILCO, AmerenCIPS, and AmerenIP.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service lives and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies.

Q. Have you previously testified on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Kentucky Public Service Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, the Federal Energy Regulatory Commission, the Utah Public Service Commission, the Arizona Corporation Commission, the Missouri Public Service Commission, the Illinois Commerce Commission, the Maine Public Utilities Commission, the Maryland Public Service Commission, the New Jersey Board of Public Utilities, the New York Public Service Commission, the Connecticut Public Utilities Regulatory Authority, and the PUC.

Q. Have you received any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: “Techniques of Life Analysis,” “Techniques of Salvage and Depreciation Analysis,” “Forecasting Life and Salvage,” “Modeling and Life

Analysis Using Simulation," and "Managing a Depreciation Study." In 2000, I became an instructor at the SDP's annual conference lecturing on "Salvage Concepts," "Depreciation Models," "Analyzing the Life of Real-World Utility Property – Actuarial Analysis," "Theoretical Reserve Imbalances and True-Up," and "Data Requirements for a Depreciation Study."

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the Pennsylvania gas plant of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"). I was retained by the Company as a depreciation consultant. UGI Gas retained me to determine the book depreciation reserve as of September 30, 2023, to determine the annual depreciation expense to be included as an element of the cost of service, and to testify in support of those two determinations in this proceeding.

I am also a sponsoring witness for UGI Gas's depreciated original cost of gas plant in service included in rate base. My testimony will address my depreciation study, the appropriate depreciation reserve for ratemaking purposes, the original cost measure of value, and the appropriate annual depreciation expense to be included in the ratemaking cost of service as of September 30, 2023.

Q. Were you responsible for the preparation of any of the Company's responses to the Commission's filing regulations that were filed in support of the Company's general rate filing?

A. Yes. I am the responsible witness for the following items in UGI Gas Book I:

Item No.	Subject
I-A-3	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account
I-A-4	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
I-A-5	Comparison of Calculated Reserve vs. Book Reserve
I-A-6	Survivor Curves and Annual Accrual Rates
I-A-7	Cumulative Depreciated Original Cost by Vintage Year
I-A-8	Trended Original Cost Methodology
I-A-9	Spot Trended Original Cost
I-A-10	Undepreciated Original Cost
I-A-11	Cumulative Trended Depreciated Original Cost
I-A-17	Net Salvage

Q. Have you previously prepared comparable studies for UGI Gas?

A. Yes. I provided testimony on depreciation matters for the Company in the prior two UGI Penn Natural Gas ("PNG") base rate cases at Docket No. R-2016-2580030 and Docket No. R-2008-2079660, the prior two UGI Central Penn Gas ("CPG") base rate cases at Docket No. R-2010-2214415 and Docket No. R-2008-2079675 and the three most recent base rate case for UGI Utilities, Inc. – Gas Division at Docket No. R-2015-2518438, Docket No. R-2018-3006814 and

Docket No. R-2019-3015162. Prior to those rate filings, I prepared exhibits for the depreciation study in UGI Gas's base rate case filed in 1995 at Docket No. R-00953297.

III. OUTLINE OF EXHIBITS C (FULLY PROJECTED), C (FUTURE) AND C (HISTORIC)

Q. Will you be sponsoring any exhibits with your direct testimony?

A. Yes, I am attaching and sponsoring the following exhibits: UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Historic). UGI Gas Exhibit C (Fully Projected) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ("FPFTY") ending September 30, 2023 for UGI Gas. UGI Gas Exhibit C (Future) presents similar summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year ("FTY") ending September 30, 2022. UGI Gas Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ("HTY") ended September 30, 2021. Each of the three exhibits is organized in a similar manner and contains information and schedules supporting the amounts applicable to each test year period. UGI Gas Exhibit C (Future) contains additional information including the supporting charts and life tables related to the service life estimates.

Q. Does UGI Gas Exhibit C (Fully Projected) accurately portray the results of your depreciation study as of September 30, 2023?

A. Yes.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Please describe the contents of the depreciation study reports, UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Fully Projected).

A. The depreciation study report in UGI Gas Exhibit C (Future) consists of eight parts including charts and tables filed in the Company's most recent service life study report prepared by me and submitted in 2019. Part I, Introduction, includes statements related to the scope of and basis for the depreciation study. Part II, Estimation of Survivor Curves, presents detailed discussions of: (1) survivor curves; and (2) methods of life analysis, including an example of the retirement rate method. Part III, Service Life Considerations, presents the relevant factors considered for estimating service lives. Part IV, Calculation of Annual and Accrued Depreciation, sets forth a description of: (1) the group procedures used for calculating annual and accrued depreciation; and (2) an explanation of the manner in which net salvage was incorporated in the calculations. Part V, Results of Study, includes a description of the results and summaries of the detailed depreciation calculations as of September 30, 2022. Part VI, Service Life Statistics, presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. Part VII, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations related to surviving original cost as of September 30, 2022. The detailed depreciation calculations present the annual and accrued depreciation amounts by account and vintage year. The remaining life annual accrual rate is also set forth in the tables of Part VII. Part VIII, Experienced and Estimated Net Salvage, contains the net salvage amortization of experienced and estimated net salvage for the years 2018 through 2022.

UGI Gas Exhibit C (Fully Projected) includes: a description of the scope, basis, and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2023. The descriptions and explanations presented in UGI Gas Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Gas Exhibit C (Fully Projected). The graphs and tables related to service life presented in UGI Gas Exhibit C (Future) also support the service life estimates used in UGI Gas Exhibit C (Fully Projected) inasmuch as the estimates are the same for all three test years, i.e., HTY, FTY, and FPFTY. The service life estimates set forth in UGI Gas Exhibit C (Historic) are the same estimates as those approved in the Company's Annual Depreciation Report ("ADR") submitted to the PUC in March 2021. The pro forma depreciation expense for UGI Gas at the end of the HTY, September 30, 2021, is the sum of the three former rate districts, UGI South, UGI North, and UGI Central.

The results of the study are set forth in Part II in UGI Gas Exhibit C (Fully Projected). Table 1, pages II-3 through II-5 of UGI Gas Exhibit C (Fully

Projected), presents the estimated survivor curve, the original cost and depreciation reserve as of September 30, 2023, and the calculated annual depreciation rate and amount for each account or subaccount of Gas Plant in Service. Table 2, pages II-6 and II-7 of UGI Gas Exhibit C (Fully Projected), presents the bring-forward to September 30, 2023, of the depreciation reserve as of September 30, 2021. Table 3, pages II-8 through II-10 of UGI Gas Exhibit C (Fully Projected), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, pages II-11 and II-12 of UGI Gas Exhibit C (Fully Projected), presents the experienced and estimated net salvage for fiscal years 2019 through 2023. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2018 through September 30, 2023. The summary tables and detailed depreciation calculations set forth in UGI Gas Exhibit C (Fully Projected) as of September 30, 2023, are organized and presented in the same manner as those presented in UGI Gas Exhibit C (Future) as of September 30, 2022.

Q. Please outline the contents of Exhibit C (Historic).

A. UGI Gas Exhibit C (Historic) is organized similarly to UGI Gas Exhibit C (Fully Projected). UGI Gas Exhibit C (Historic) includes: a description of the scope, basis, and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2021. The service life estimates used in the HTY period were based on the survivor curve estimates set forth in the ADR submitted to the PUC in March 2021. The same survivor curve estimates were used in each of the three respective test year periods and were based on a service life study submitted in 2019 using plant accounting data through fiscal year-end 2017. The summary tables and detailed depreciation calculations as of September 30, 2021, are organized and presented in the same manner as those as of September 30, 2023, with two exceptions. Tables 2 and 3 presented in UGI Gas Exhibit C (Fully Projected) are not necessary and, therefore, are not presented in UGI Gas Exhibit C (Historic).

IV. THE DEPRECIATION STUDY - OVERVIEW

Q. Please describe what you mean by the term "depreciation".

A. My use of the term "depreciation" is in accord with the definition set forth in the Uniform System of Accounts prescribed for Class A and Class B Natural Gas Companies. "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, requirements of public authorities, and the exhaustion of natural resources.

In the study that I performed, which is the basis for my testimony, I used the straight line remaining life method of depreciation, with the average service life and equal life group procedures. The annual depreciation is based on a system of depreciation accounting that aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of the unit, or group of assets, in a systematic and rational manner. For clarity of presentation, the detailed depreciation calculations are presented by account, vintage year and former rate district, the sum of which totals to the consolidated PA-jurisdictional UGI Gas company which excludes a small portion of the UGI gas system located in Maryland. The depreciation summary tables present the results on a total PA-jurisdictional UGI Gas basis.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation that were used in the Company's March 2021 ADR?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used by the Company for over thirty years. The depreciation methods and procedures are described further in Part II of UGI Gas Exhibit C (Future).

For General Plant Accounts 391, 393, 394, 395, 397, and 398, I used the straight line remaining life method of amortization. The annual amortization is based on amortization accounting, which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

V. ORIGINAL COST MEASURE OF VALUE

Q. What is the original cost of gas plant to be included in rate base in this proceeding?

A. As of September 30, 2023, the original cost of gas plant in service is $5,042,025,320 as shown in column 4 of Table 1 on pages II-3 through II-5 of UGI Gas Exhibit C (Fully Projected). This amount includes $4,751,865,847 of Gas Plant and $290,159,473 of Other Utility Plant allocated to UGI Gas. Other Utility Plant is primarily comprised of plant assets included in Common Plant and Information Services ("IS"). The assets included in Common Plant and IS are assets that are shared and jointly used between UGI Gas and UGI Electric. The costs related to Common Plant and IS are allocated to UGI Gas at 88.97 percent and 91.68 percent, respectively. Also, the full cost of the buildings at the Empire Service Center ("Empire") in Wilkes Barre, PA were included in Gas Division. However, personnel of UGI Electric share portions of the buildings at that location and therefore a portion of the cost related to Empire was deducted from UGI Gas and allocated to UGI Electric.

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI Gas's accrued depreciation for ratemaking purposes as of September 30, 2023?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2023, to be $1,318,560,331.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over thirty years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve set forth in the Company's financial statements and approved annually in connection with the Company's submission of its annual depreciation report each March to the Commission.

Q. How did you determine UGI Gas's allocated book depreciation reserve as of September 30, 2022?

A. The book depreciation reserve attributable to UGI Gas as of September 30, 2022, is set forth in column 5 of Table 1 of UGI Gas Exhibit C (Future). Table 2 of UGI Gas Exhibit C (Future) is an annual bring-forward of the book depreciation reserve as of September 30, 2021, using estimated accruals, retirements, salvage, and cost of removal for the twelve months from October 2021 through September 2022. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2021, the estimated reserve activity, and the ending reserve balance as of September 30, 2022. The estimated reserve activity consists of depreciation accruals (column 3), amortization of net salvage (column 4), projected retirements (column 5), projected salvage (column 6), and projected cost of removal (column 7). Table 3 of UGI Gas Exhibit C (Future) sets forth the calculation of the estimated depreciation accruals by plant account, which is carried forward to column 3 of Table 2. The book reserve as of September 30, 2021, by plant account, shown in column 2 of Table 2, was obtained from UGI Gas's books and records and are the same amounts set forth in Table 1 of Exhibit C (Historic).

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2022.

A. The depreciation accruals for the twelve months ended September 30, 2022, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2021, to the projected average 2022 plant balance. The average balance for the twelve months ended September 30, 2022, is computed in columns 2 through 7 of Table 3 and is based on the projected additions, retirements, and transfers in columns 3 through 5.

Q. With reference to Table 2, column 4, please explain what you mean by "the amortization of net salvage" and explain the manner in which you projected it.

A. The amortization of net salvage is the annual provision for recovering experienced negative net salvage. This process for recognizing net salvage in the cost of service is in accordance with Pennsylvania ratemaking practice. The amortization of net salvage is based on experienced net salvage during the preceding five-year period, October 1, 2016 through September 30, 2021.

Q. Please explain the manner in which you projected the retirements, salvage, and removal costs that are shown in columns 5, 6, and 7 of Table 2.

A. Retirements were projected by plant account by applying the average retirement ratio, expressed as a percent of additions, for the five years 2017 through 2021, to FTY and FPFTY additions for most plant accounts. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. All units are retired per books when the age of the vintage reaches the amortization period. Therefore, all vintages that reached or exceeded the amortization period were retired during the FTY for certain General Plant accounts subject to amortization accounting. Salvage and removal costs were projected by plant account by applying the average salvage and cost of removal ratios, expressed as a percent of retirement amounts, for the five years 2017 through 2021, to the projected retirement amounts.

Q. Was the book reserve as of September 30, 2023, estimated using the same methodology?

A. Yes, it was essentially the same methodology with one minor exception. The book depreciation accruals calculated for fiscal year 2023 were based on applying the depreciation rate to average monthly plant balances for purposes of calculating the book reserve as of September 30, 2023.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI Gas's annual depreciation expense to be included as an element in the cost of service for purposes of this proceeding?

A. Yes, I have. The annual depreciation expense is $133,907,352 and consists of $127,823,602 of annual accruals to recover original cost and $6,083,750 of net salvage amortization. These amounts are set forth in column 8 of Table 1 in UGI Gas Exhibit C (Fully Projected).

Q. How did you determine the annual accruals of $133,907,352?

A. The determination of annual depreciation accruals consists of two phases. In the first phase, survivor curves are estimated for each plant account or subaccount. In the second phase, the composite remaining lives and annual depreciation accruals are calculated based on the service life estimates determined in the first phase.

The determination of annual amortization amounts consists of the selection of amortization periods and the calculation of amortization amounts based on the remaining amortization period and the unrecovered cost for each vintage.

Q. Please describe the manner in which you estimated the service life characteristics for each depreciable group in the first phase of the study.

A. The service life study consisted of compiling historical data from records related to UGI Gas's gas plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from engineering management and operating personnel concerning UGI Gas's practices and plans as they relate to plant operations; and interpreting the above data to form judgments of average service life characteristics.

Q. What historical data did you analyze for the purpose of estimating the service life characteristics of UGI Gas's gas plant?

A. The data consisted of the entries made by UGI Gas to record gas plant transactions during the period 1951 through 2017. The transactions included additions, retirements, transfers, acquisitions, and the related balances. I classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. What method did you use to analyze these service life data?

A. I used the retirement rate method of life analysis. The retirement rate method is the most appropriate method when aged retirement data are available because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type survivor curve and were not used.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table, which, when plotted, formed an original survivor curve. Each original survivor curve, as plotted from the life table, represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa type survivor curves were used in these interpretations. The results of the retirement rate analyses are presented in Part VI of UGI Gas Exhibit C (Future).

Q. Please explain briefly what an "Iowa type survivor curve" is and how you use it in estimating service life characteristics for each depreciable group.

A. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type survivor curves ("Iowa curves"). The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. Iowa curves are the accepted survivor curves for Pennsylvania, as well as the remaining 49 states, and have been for many years.

Iowa curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the qualitative outlook for future retirements.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system, and the relative height of the mode. For example, the Iowa 35-R2 curve indicates an average service life of thirty-five years; and a Right-skewed, or R, type curve (the mode or highest frequency of retirements occurs after average life for right modal curves). It also provides a relatively low height, 2, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. Did you physically observe plant and equipment in the field?

A. Yes. Field trips are conducted periodically in order to be familiar with the operation of the Company and observe representative portions of the plant. Field trips are conducted each time a service life study is performed. Service life study reports are submitted to the Commission every five years, at a minimum. UGI Gas's most recent service life study report was performed in 2018 and submitted in 2019 in connection with the 2019 base rate case filing at Docket No. R-2018-3006814, Exhibit C (Future). Facilities visited during field trips generally include representative city gate stations, district regulating stations, service centers, etc. The specific dates and locations visited during recent field trips are listed in Exhibit C (Future) in Part III. A general understanding of the function of the plant and information with respect to the reasons for past retirements and expected causes of retirements are obtained during these field trips. This knowledge and information was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. Please describe the second phase of the process that you used in order to determine annual depreciation for ratemaking purposes.

A. After I estimated the service life characteristics for each depreciable group, I calculated annual depreciation accruals for each group in accordance with the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1982 and remaining lives consistent with the equal life group procedure for plant installed in 1982 and subsequent years. Summary tabulations of the survivor curve estimates and the annual accrual rates and amounts are set forth on Table 1 of UGI Gas Exhibit C (Historic), UGI Gas Exhibit C (Future), and UGI Gas Exhibit C (Fully Projected). The detailed tabulations of the depreciation calculations are presented in Part III of UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and in Part VII of UGI Gas Exhibit C (Future).

Q. Please briefly describe the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life.

Q. Please briefly describe the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1982.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please briefly describe the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1982 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives. In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes the portion of the property that experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Please briefly describe the amortization of certain General Plant accounts.

A. General Plant Accounts 391, 393, 394, 395, 397, and 398 include a very large number of units but represent a very small percent of depreciable gas plant.

Depreciation accounting is difficult for these assets, inasmuch as periodic inventories are required to properly reflect plant in service. Many utilities have changed to amortization accounting for general plant as a practical and reasonable solution that avoids significant accounting expenditures for such a small percent of plant.

In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. That is, there is no dispersion of retirement. All units are retired per books when the age of the vintage reaches the amortization period.

VIII. ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE

Q. Please illustrate the procedure followed in your depreciation study and the manner in which it is presented in UGI Gas Exhibit C (Future) using an account as an example.

A. I will use Account 376.1, Mains – Primarily Steel, to illustrate the manner in which the study was conducted. Account 376.1 represents 15 percent of the total depreciable gas plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1951 through 2017. These data have been coded in the course of UGI Gas's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The plant additions, retirements, and other plant transactions were analyzed by the retirement rate method of life analysis.

This account includes primarily cathodically-protected, steel mains, although some bare steel mains are still in service. As detailed in UGI Gas Exhibit C, the Iowa 73-R2.5 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The 73-R2.5 is a very good fit of the company's historical plant accounting data, consistent with engineering outlook and within the typical range of service lives used by other gas companies for steel mains. The original life table for the 1960-2017 experience band is set forth on pages VI-41 through VI-46.

The calculation of annual depreciation, the second phase, for the original cost of steel mains in service as of September 30, 2022, is presented by vintage in Part VII on pages VII-55 through VII-63 of UGI Gas Exhibit C (Future) for Gas Plant in Service. The detailed depreciation calculations as of September 30, 2023, are presented in Part III of Exhibit C (Fully Projected). The tabular presentations of the detailed depreciation calculations in Part VII of Exhibit C (Future) are similar in kind to those set forth in Part III of Exhibit C (Fully Projected). The expectancy and average life derived from the estimated survivor curve for each vintage were used to calculate the accrued depreciation by the average service life procedure for 1981 and prior vintages.

The accrued depreciation for vintages subsequent to 1981 was calculated by the equal life group procedure using the Iowa 73-R2.5 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, through the use of a computer program, into depreciable groups according to the expected service lives as defined by the Iowa 73-R2.5 survivor curve. The accrued depreciation was derived for each equal life group, based on its service life, and the totals shown for the vintages are the summations of the individually derived amounts.

The book reserve was allocated to vintages based on the calculated accrued depreciation. The remaining lives of the vintages were based on the Iowa 73-R2.5 survivor curve, the attained age, and the same group procedures as were used to calculate accrued depreciation. The future book accruals (original cost less allocated book reserve) were divided by the remaining lives to derive the annual depreciation accruals by vintage.

The total depreciation accrual on page VII-63 of UGI Gas Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-4 of the exhibit and divided by the total original cost in column 4 in order to calculate the annual depreciation accrual rate in column 7. A similar process was used for the FPFTY.

Q. Is the procedure you described for Account 376.1 typical of that followed for most of the plant investment?

A. Yes, it is, inasmuch as the straight line method, the average service life, and the equal life group procedures were used for most of the depreciable plant.

Q. Please illustrate the procedure followed for the amortization of certain General Plant accounts and the manner in which it is presented in UGI Gas Exhibit C (Future) using an account as an example.

A. I will use Account 394, Tools, Shop and Garage Equipment, to illustrate the amortization procedure. As the initial step of the amortization procedure, an amortization period of 20 years was selected based on the period during which such equipment renders most of its service, the amortization periods used by other utilities, and the service life estimate previously used for depreciation accounting.

The calculation of the annual amortization as of September 30, 2022, is presented by vintage in Part VII on pages VII-162 and VII-163 of UGI Gas Exhibit C (Future). The calculated accrued amortization is based on the ratio of the vintage's age to the amortization period. The book reserve for vintages older than the amortization period was set equal to the original cost. The remaining book reserve was allocated to vintages based on the calculated accrued depreciation. The future book accruals or amortizations (original cost less assigned or allocated book reserve) were divided by the remaining amortization period to derive the annual amortizations by vintage.

The total amortization on page VII-163 of UGI Gas Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-5 of UGI Gas Exhibit C (Future). A similar process was performed for UGI Gas Exhibit C (Fully Projected) and UGI Gas Exhibit C (Historic). That is, the calculation of the annual amortization related to the original cost of Tools, Shop and Garage Equipment in service as of September 30, 2023, is presented by vintage on pages III-161 and III-162 of UGI Gas Exhibit C (Fully Projected) and summarized in Table 1 on page II-4.

Q. Briefly explain the methods used for the remaining portion of the depreciable plant.

A. The life span procedure was applied to major structures in Account 390. The life span procedure was used for groups such as buildings in which concurrent retirement of all property in the group is expected. The life span of both the original installation and subsequent additions is the number of years between installation and final retirement of the group. The complete details, by vintage, of the accrued depreciation and remaining life accrual calculations are set forth for each structure in Part III of UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and in Part VII of UGI Gas Exhibit C (Future).

IX. THE NET SALVAGE AMORTIZATION CLAIM

Q. Please briefly describe the accounting treatment regarding net salvage for public utilities operating in Pennsylvania.

A. In accordance with the Uniform System of Accounts and the rules for recovery of net salvage established by the Pennsylvania Superior Court in *Penn Sheraton Hotel v. Pa. P.U.C.*, 198 Pa. Super. 618, 184 A.2d 324 (1962), net salvage is charged to the depreciation reserve and is amortized over a five-year period beginning with the year after net salvage is actually incurred. These accounting procedures were affirmed by the Commission in CPG's (formerly PPL Gas Utilities Corporation ("PPL Gas")) 2006 rate filing (Docket No. R-00061398) and have been utilized by UGI Gas in their rate cases ever since. This procedure is consistent with how other Pennsylvania public utilities account for net salvage and is the method used in preparing the Company's ADR submitted each year to the Commission.

Q. Earlier in your testimony you indicated that UGI Gas's annual depreciation expense consists, in part, of $6,083,750 of net salvage amortization. How did you determine that amount?

A. The $6,083,750 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2018 through September 30, 2023. Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most gas utilities, including UGI Gas, cost of removal exceeds gross salvage resulting in negative net salvage. Negative net salvage is recorded to the depreciation reserve as a debit, which reduces the depreciation reserve. Charges related to the negative net salvage amortization are recorded to the depreciation reserve as a credit in the five years subsequent to the initial recording of the negative net salvage amount. Therefore, the negative net salvage amount will have been fully amortized after five years and the net effect on the depreciation reserve is zero. Detailed data related to the experienced and estimated cost of removal and salvage are presented in Part VIII of UGI Gas Exhibit C (Future) and Part IV of UGI Gas Exhibit C (Fully Projected).

Q. Do you have any other comments on the other items which you are sponsoring in this proceeding?

A. Yes. The above testimony does not describe the responses to filing requirements set forth in Items I-A-5, I-A-6, and I-A-7. In general, these responses are self-explanatory. The response to I-A-5 is a comparison of the actual and projected book depreciation reserve with the calculated accrued depreciation as of the end of the HTY, FTY, and FPFTY, respectively. The response to I-A-6 presents the survivor curves used in the most recent general rate proceeding and the annual accrual rates that resulted from the use of these curves. The response to I-A-7 is the cumulative depreciated original cost by installation year as of the end of the test years. The amounts requested in response to I-A-7 are set forth in UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Future) in the section titled "Cumulative Depreciated Original Cost."

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS STATEMENT NO. 5

VICKY A. SCHAPPELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 5

Direct Testimony of
Vicky A. Schappell

Topics Addressed: **Capital Planning**

Dated: January 28, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vicky A. Schappell. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed as a Principal Analyst, Capital Planning by UGI Utilities, Inc. ("UGI"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric") and the Gas Division ("UGI Gas" or the "Company"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Gas Exhibit VAS-1 to my testimony.

Q. What are your responsibilities as Principal Analyst?

A. As Principal Analyst, I supervise a team of Analysts in preparing the annual capital budgets for UGI Gas and UGI Electric. I am responsible for obtaining budget inputs from various departments including Engineering, Operations, Corrosion, Marketing, Information Services, and the Building and Grounds Departments. I collaborate with the Vice President of Engineering, the Vice President of Operations, the Director of Engineering Design, the Senior Director Marketing and Community Relations, the Director of Pipeline System Planning and Optimization, the Senior Director Financial Planning and Analysis and Senior Engineering Managers to monitor annual capital budget performance and develop strategies to limit variances in capital installations and spending. I also work closely with the President of UGI in developing the overall capital spend strategy. I have prepared schedules and discovery requests for past rate cases. Also, I am responsible for preparing UGI Gas's Annual Asset Optimization Plan. Additionally, I had an integral role in developing an expanded capital spending monitoring process (as a result of the Company's recent accelerated capital investments programs). This involved upgrading the Company's capital planning, forecasting and budgeting tool, which was implemented in UNITE Phase III-Enterprise Performance Management ("EPM"), which went live in October 2020.

Q. Have you previously presented testimony in proceedings before a regulatory agency?

A. Yes. I previously presented testimony in the 2020 UGI Gas Base Rate Case at Docket No. R-2019-3015162.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. In my testimony, I will address the Company's capital planning process for this proceeding.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, in addition to UGI Gas Exhibit VAS-1, I am sponsoring UGI Gas Exhibit VAS-2. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. CAPITAL PLANNING

Q. Please describe the categories of projects included in the capital budget for UGI Gas.

A. The principal categories for which UGI Gas develops capital budgets are: (1) replacement and betterment infrastructure; (2) new business; (3) information technology; (4) other capital spending; and (5) removal and salvage. The budgeting process is further described in the direct testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2).

Q. What are replacement and betterment projects?

A. Replacement and betterment ("R&B") projects improve or replace existing infrastructure and include, but are not limited to, leak remediation, pipe relocations, material upgrades, service renewals, reliability improvements, and metering and regulation upgrades.

Q. How does UGI Gas determine which R&B projects are included in the capital budget for a given year?

A. UGI Gas enters R&B projects into its capital budget according to a risk-based prioritization process.

Q. Please describe this risk-based prioritization process.

A. This process prioritizes the replacement of cast iron and bare steel pipe, which are more susceptible to failure from corrosion, cracks, and leakage (as compared to other pipe materials). Risk evaluations for mains are based on numerous factors, including condition, age, coating, type of ground cover, geographical proximity to structures and prior leak and/or break history. UGI Gas reviews these factors annually to identify the highest risk pipe segments and prioritize them for replacement.[1] Specifically, commercial risk evaluation software is used in concert with a team of Subject Matter Experts to evaluate, prioritize, and bundle replacement projects. Furthermore, UGI Gas's Distribution Integrity Management Plan ("DIMP") and Transmission Integrity Management Program ("TIMP") provide a detailed listing of factors considered in the risk-based evaluation, which may cause specific projects to be reprioritized for replacement on a more accelerated basis. This hybrid approach targets the highest risk mains first, while also balancing the need to maximize the efficient deployment of capital and resources.

UGI Gas's prioritization of projects for its capital budgets also is consistent with its Long-Term Infrastructure Improvement Plan ("LTIIP"), which is described in more detail in the direct testimony of UGI Gas witness, Timothy J. Angstadt (UGI Gas Statement No. 9). LTIIP replacement investments are in turn identified and prioritized on a risk basis in accordance with UGI Gas's DIMP.

Q. What are new business projects?

A. New business projects provide new or upgraded gas service to customers and may involve the installation of new gas mains and services or conversions to natural gas service (from other heating sources).

[1] When replacing mains, the Company also replaces associated distribution equipment, including service lines, as well as installing or replacing safety and monitoring devices (excess flow valves), meters, risers, and meter bars. Additionally, indoor meters are relocated to an outside location, except in certain circumstances. Similarly, regulator stations and service regulators are reviewed and prioritized for replacement based on nearby main replacement projects or required upgrades due to the updated equipment installed as part of the main replacement program.

Q. Please describe how the new business infrastructure projects are selected for inclusion in the capital budget.

A. These projects are selected for inclusion in the capital budget according to forecasts of new business opportunities, projections of customer conversions, and plans for new construction and development projects. New business main extensions under the Company's Growth Extension Tariff ("GET") are planned, prioritized, and included in the budget based on: (1) the guidelines outlined in the Company's Tariff; and (2) projections of customer demand (as measured by new service inquiry responses).

Q. What are information technology projects?

A. Information technology ("IT") projects enhance the Company's IT systems. These projects improve the Company's methods (including computerized systems and hardware/software applications) for managing capital projects in a safe and reliable manner. Further, these projects facilitate the Company's ability to enter, store, retrieve, and send data/information related to such projects.

Q. Please describe the prioritization process used to evaluate information services projects.

A. IT projects are prioritized (for inclusion in the budget) based on the need for new systems and hardware to continue performing capital projects in a safe and reliable fashion. Budget determinations are prioritized by the Company's IT Prioritization Committee, based on overall business impact, availability of system support, and resource availability.

Q. What are other capital projects?

A. Other capital projects include building-related projects, corrosion control projects, capital tool purchases, and fleet purchases. Building-related projects consist of building and land purchases, building improvements/renovations, and the purchase of furniture. Corrosion control projects include upgrades and replacements of cathodic protection systems for mains. Capital tool projects encompass new tool purchases for field use during capital projects. These tools include tapping and stopping equipment, safety tools, and leak detection equipment. Fleet purchases are needed to maintain a reliable mode of transportation for field employees to perform their daily functions. These acquisitions include SUVs, pickup trucks, cargo vans, service body trucks, compressor crew trucks, vacuum trucks, aerial lift trucks, dump trucks, backhoes, excavators, forklifts, and equipment trailers for backhoes and excavators.

Q. Please describe the prioritization process used to evaluate other capital projects.

A. Building-related projects are prioritized (for budget inclusion) based on safety/security, regulatory, or financial and strategic needs. Regulatory driven projects originate from audit observations. Physical security audits may prompt the installation of fencing, gates and access controls. Corrosion control projects (involving coated steel main replacements) are prioritized (for budget inclusion) according to requirements set forth in the Federal Gas Safety Regulations (49 C.F.R. Part 192).[2] Corrosion control projects also may depend on

[2] Transmission lines may be replaced due to corrosion that affects wall thickness pursuant to 49 C.F.R. § 192.485. Additionally, portions of transmission lines (with localized corrosion pitting) may be replaced pursuant to 49 C.F.R. § 192.485. Similarly, distribution lines with corrosion (or portions thereof with localized pitting corrosion) may be replaced pursuant to 49 C.F.R. § 192.487. Lines also may need to be replaced if they lack cathodic protection systems, as detailed in 49 C.F.R. § 192.463.

unrepairable leakages or emerging main issues. Capital tool projects are prioritized (for budget inclusion) according to the useful life of the existing assets. Fleet purchases are prioritized (for budget inclusion) based on age, condition, maintenance costs, and mileage of the existing asset.

Q. What are removal and salvage projects?

A. Removal and salvage projects include main and service retirements where assets are not replaced. Additionally, this category of spend includes the environmental projects performed at UGI Gas (including mercury regulator remediation and waste disposal).

Q. Please describe the prioritization process used to evaluate removal and salvage projects.

A. These projects are identified and prioritized (for budget inclusion) through the same risk-based prioritization process used for the R&B projects. Environmental projects are entered into the budget as they are identified in the field. These kinds of capital projects are budgeted on a project level and are rolled up to UGI Gas and UGI Electric (as appropriate). Capital projects of general application to UGI are budgeted by UGI and costs are allocated to the divisions in accordance with the Modified Wisconsin Formula ("MWF").

Q. How have UGI Gas's actual capital additions compared to budgeted capital additions (in relation to the above-described categories)?

A. Over the past five years, the Company's total budgeted capital additions (including all of the above-described categories) was $1,700,335,000, while the total actual capital additions was $1,666,254,000; there was a $34,081,000 variance. More specifically, during this period, the Company's plant additions were 98.0% of its budget. (See UGI Gas Exhibit VAS-2). This close correlation between budgeted and actual plant placed in service over the past five years further supports the Company's claimed level of plant in service in this case, which is discussed in the testimony of UGI Gas witness Vivian K. Ressler (UGI Gas Statement No. 3).

III. UNITE PHASE III-ENTERPRISE ASSET MANAGEMENT ("EAM")

Q. Please describe the asset data collection tool that will be implemented in UNITE Phase III-EAM.

A. UNITE's current EAM project is a multi-phase project that will develop a new database to manage Company assets, including supporting applications. In 2021, the Company started the EAM's asset data collection phase, which focuses on the identification, standardization and capture of asset data information across UGI. It will cost UGI (the Electric and Gas Divisions) approximately $43,000,000 to replace its existing system and leverage the same tools for similar process that will occur across UGI by the end of the FPFTY. One goal will be eliminating paper-based processes and providing automation to improve reliability and streamline operations. With respect to systems, the new EAM will be integrated with a consolidated gas and electric Geographic Information System ("GIS"), and other systems. The asset data collection phase is laying the groundwork for the future phases of UNITE, including a new GIS system.

The new EAM project will result in many positive impacts and benefits to the Company's teams. The new system will reduce redundancies in field crew workflows and forms associated with the installation of Company assets to serve customers. Less back-office work will be required to document asset installations, as more complete and accurate asset data will be gathered and uploaded in the field upon installation.

Some of the benefits will include real-time asset data updates, reduced mapping delays, more accurate asset detail and location cataloguing, and barcode scanning capability. These capabilities will reduce data entry time and potential asset location errors. The Company will be able to easily track and locate its assets in the event of recalls, markouts, maintenance, or other necessary rework. More specifically, field personnel will utilize handheld devices that scan material attributes as contained in asset barcodes from the manufacturer (for storage in the information system). These devices will capture and utilize real world accurate locations for each installed asset (by way of actual coordinates obtained from satellite technology in the field).

One key change will be that the data for newly installed assets will be immediately visible/accessible in digital form (*i.e.*, system maps). Updates also will undergo a final review and approval by the Mapping Department after the new asset data is uploaded to the system. This will avoid line hits and improve the accuracy of facility mark outs. Improving UGI's spatial data is one of several data cleansing and enhancement initiatives to support UGI's future EAM data-centric business model. Based on a split of plant in service between UGI Gas and UGI Electric, $41,200,001 (of the total $43,000,000 amount) is being included in the gas capital budget for the fully projected future test year ("FPFTY") in this case.

IV. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT VAS-1

Vicky A. Schappell

Principal Analyst – Capital Planning

UGI Utilities, Inc. (Reading, PA)

Principal Analyst - Capital Planning	January 2020-Present
Senior Analyst - Capital Planning	April 2018-January 2020
Senior Supervisor Plant Accounting	December 2014-April 2018
Senior Analyst - General Ledger	September 2011-December 2014
Analyst II – General Ledger	September 2008-September 2011

Teleflex Medical (Reading, PA)

Accounting Supervisor	December 2007-September 2008
Senior Accountant – Financial Reporting	March 2003-December 2007
Staff Accountant – Financial Reporting	October 1999-March 2003

Heffler, Radetich & Saitta, LLP (Philadelphia, PA)

Auditor	May 2007-October 1999

Education

B.S. in Accounting, Shippensburg University, 1997

Previous Testimony

UGI Gas Base Rate Case	Docket No. R-2019-3015162

UGI GAS

EXHIBIT VAS-2

UGI UTILITIES, INC. - GAS DIVISION
Plant Placed in Service compared to Budget
$ amounts in '000s

	2017		2018		2019		2020		2021		5 Year Total		
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Actual vs. Budget
Growth	$ 44,776	$ 39,788	$ 58,645	$ 77,356	$ 69,288	$ 61,681	$ 65,000	$ 72,568	$ 65,503	$ 83,941	$ 303,212	$ 335,334	$ 32,122
IT	$ 63,661	$ 76,619	$ 22,338	$ 14,345	$ 67,809	$ 63,652	$ 36,203	$ 12,900	$ 10,433	$ 19,105	$ 200,443	$ 186,621	$ (13,822)
Other	$ 17,342	$ 14,073	$ 17,806	$ 12,756	$ 63,907	$ 58,437	$ 27,987	$ 28,259	$ 65,000	$ 48,527	$ 192,042	$ 162,053	$ (29,990)
Replacement and Betterment	$ 149,591	$ 166,349	$ 185,392	$ 204,472	$ 196,274	$ 189,279	$ 225,308	$ 192,251	$ 248,073	$ 229,895	$ 1,004,637	$ 982,246	$ (22,391)
Total Additions	$ 275,370	$ 296,829	$ 284,181	$ 308,929	$ 397,278	$ 373,049	$ 354,497	$ 305,979	$ 389,008	$ 381,469	$ 1,700,335	$ 1,666,254	$ (34,081)
					$ -						(1)	(2)	

Capital Spend as % of Budget **(2) / (1)** **98.0%**

BOOK IV

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 6 – PAUL R. MOUL
UGI GAS STATEMENT NO. 7 – NICOLE M. MCKINNEY
UGI GAS STATEMENT NO. 8 – SHERRY A. EPLER
UGI GAS STATEMENT NO. 9 – TIMOTHY J. ANGSTADT
UGI GAS STATEMENT NO. 10 – CONSTANCE E. HEPPENSTALL
UGI GAS STATEMENT NO. 11 – JOHN D. TAYLOR

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 **Effective: March 29, 2022**

UGI GAS STATEMENT NO. 6

PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 6

Direct Testimony of
Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Topics Addressed:	**Capital Structure** **Rate of Return**

Dated: January 28, 2022

UGI Utilities, Inc. - Gas Division
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
g	Growth rate
IGF	Internally Generated Funds
IRPA	Interest Rate Protection Agreement
LDC	local distribution companies
Lev	Leverage modification
LT	Long Term
OCI	Other Comprehensive Income
P-E	Price-earnings
PUC	Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
UGI Gas	UGI Utilities, Inc. – Gas Division
UGI	UGI Corporation
V	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission ("PUC" or the "Commission") should recognize in determining the revenues UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") should be authorized to recover as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit B, which is a multi-page document consisting of Schedules one (1) through fourteen (14).

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company?

A. My conclusion is that the Company should be afforded an opportunity to earn a 7.96% overall rate of return, which includes an 11.20% rate of return on common equity. My 11.20% rate of return on common equity includes recognition of the exemplary performance of the Company's management and is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of capital for the Company.

My overall rate of return recommendation is determined by using the weighted average cost of capital approach. This approach provides a means to apportion the return to each class of investor. The calculation of the weighted average cost of capital requires the selection of appropriate capital structure ratios and a determination of the cost rate for each capital component. The resulting overall cost of capital when applied to the Company's rate base will provide a level of return which will compensate investors for the use of their capital. My overall cost of capital recommendation is set forth below and is shown on page 1 of Schedule 1.

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Total Debt	44.88%	3.98%	1.79%
Common Equity	55.12%	11.20%	6.17%
Total	100.00%		7.96%

This overall rate of return is applicable to the September 30, 2023, fully projected future test year ("FPFTY") and the initial period that the Company's proposed rates will be effective.

Q. Is the market impact of the COVID-19 Pandemic reflected in your analysis of the cost of equity for the Company?

A. Yes. My cost of equity analysis reflects the impact of the COVID-19 Pandemic ("Pandemic"). These events have had a significant impact on the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the Pandemic. These events led to the end of the record-setting 128-month economic expansion. As we entered a recession in February 2020, extraordinary actions were taken by the Federal Open Market Committee

("FOMC") to address these disruptions. Over the course of the Pandemic, stock prices have rebounded and have reached new highs. Economic growth has rebounded and has produced renewed inflation to levels not seen in three (3) decades. Supply shortages have also significantly impacted the consumer sector of the economy. Energy prices have increased as well, with the commodity cost of natural gas spiking upward. While short-term interest rates remain at historically low levels, longer term interest rates began to rise in February 2021. At this point, short-term interest rates are poised to increase when the FOMC ends its bond buying program. The FOMC has indicated that several increases in the Fed Funds rate will likely occur in 2022. Stock market performance has reacted to renewed economic growth by reaching new highs. I have considered these events as they impact the inputs that I used in the various models of the cost of equity.

Q. What factors have you considered in the determination of the Company's cost of equity in this proceeding?

A. UGI Gas is a division of UGI Utilities, Inc. ("UGI Utilities"), a wholly-owned subsidiary of UGI Corporation ("UGI" or the "Parent Company"). The Company provides natural gas distribution service to more than 672,000 customers in forty-five (45) eastern and central Pennsylvania counties. The Company's service territory contains several production centers for basic industries involved in steel and aluminum manufacturing and fabrication, chemicals, and food processing. Throughput to on-system customers in fiscal year 2020 was represented by approximately 19% to sales customers and approximately 81% to transportation customers. The significant portion of the Company's throughput to industrial customers (68% of total throughput) makes the Company a much higher risk utility as compared to the Gas Group. The Company obtains its natural gas supplies from producers and marketers and has transportation arrangements through connections to several interstate pipelines and storage facilities. The Company has storage arrangements for natural gas inventory. UGI Utilities also provides electric delivery service, through UGI Electric, to more than 62,500 customers in portions of Luzerne and Wyoming Counties.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence, the cost of equity for a natural gas utility, such as UGI Gas. In this regard, I have considered four (4) well-recognized models. These methods include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's rate of return on common equity is 11.20%, including 0.20% in recognition of the Company's exemplary management performance.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. How have you measured the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of companies engaged in the distribution of natural gas. I will refer to these companies as the "Gas Group" throughout my testimony. I began with all of the gas utilities contained in The Value Line Investment Survey, which consists of ten (10) companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. However, I eliminated one (1) company from the Value Line group. UGI Corporation was removed due to its diversified businesses consisting of six (6) reportable segments, including propane, two (2) international LPG segments, natural gas utility, energy services, and electric generation. The remaining nine (9) companies in the Gas Group are identified on page 2 of Schedule 3. These are the same companies that were used to apply the cost of equity models in the recent Quarterly Earnings Report approved by the Commission on October 9, 2021.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the methods/models for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

the cost of equity for an individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

DCF	11.21%
Risk Premium	10.50%
CAPM	13.55%
Comparable Earnings	12.70%

From these measures, I recommend a cost of equity of 11.00%, to which 0.20% should be added in recognition of the Company's exemplary management performance. My recommendation is on the conservative side for UGI Gas because it is based on the Gas Group that does not have the Company's high-risk attributes related to its high level of industrial throughput. My determination of the cost of equity focuses on the DCF and Risk Premium approaches that provide a return of 10.86% (11.21% + 10.50% = 21.71% ÷ 2 = 10.86%) and on all of the market-based models, i.e., DCF, Risk Premium and CAPM, that provide a return of 11.75% (11.21% + 10.50% + 13.55% = 35.26% ÷ 3 = 11.75%). My 11.20% cost of equity recommendation includes 20 basis points or 0.20% recognition for the exemplary performance of the Company's management and falls within the range of 10.86% to 11.75% indicated above. Mr. Brown's testimony in UGI Gas Statement No. 1 demonstrates that the Company ranks high in customer service and management effectiveness. To obtain new capital to support an expanded construction program and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Along these lines, the Company is spending considerable amounts of new capital, which are large by historical standards, which will put a strain on financial performance in the short run. In recognition of its performance, the Company should be granted an opportunity to earn an 11.20% rate of return on common equity.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of natural gas utilities?

A. Natural gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers. The gas distribution industry also faces the risk associated with increased availability of renewable energy sources, expanded emphasis on energy efficiency, and potential initiatives directed toward decarbonization as a national energy policy.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues. The testimony of Company witnesses discusses the investments that the Company has made and will continue to make to address these issues and expansion requests, which have led to increased external capital requirements.

Q. Does the Company face competition in its natural gas business?

A. Yes. The Company's service territory is within or in close proximity to the Marcellus Shale production area, which provides additional risk for it compared to many companies in the Gas Group. Natural gas utilities generally face significant competition from alternative energy sources. The Company faces direct competition from electricity, fuel oil, and propane in its service territory, and there is now an increased emphasis on electricity as an energy source. Propane and fuel oil have an advantage because they are not inhibited by regulatory constraints when conducting marketing and pricing their services. This situation is unlike that of UGI Gas, where specific thresholds must be satisfied for system expansions, where promotional activities are constrained and prices are regulated. The Company also faces the risk associated with throughput to interruptible customers whose deliveries are influenced by global oil prices. Further, the Company has identified seventeen (17) customers that could potentially bypass its system.

Q. What are the risks associated with the Company's large volume customers?

A. The Company's risk profile is strongly influenced by throughput delivered to large competitive market customers. Industrial customers represent 68% of throughput, but these customers represent about one-half of one percent of total customers. Moreover, the Company's top ten (10) customers represent 185.8 million Mcf of total throughput or about 64% of the total. Electric generation, manufacturing, and food processing are among these customers. Steel and aluminum manufacturing and fabrication face a number of challenges including international competition, increased costs, and fluctuating demand for their products. Industrial sales are generally higher in risk than sales to other classes of customers. Success in this segment of the Company's market is subject to the business cycle and the price of alternative energy sources. Moreover, external factors can also influence the Company's sales to these customers, which face competitive pressures on their own operations from other facilities outside the Company's service territory.

Q. Please detail the regulatory risks faced by the Company?

A. Among other factors, regulatory risks faced by the Company are elevated when it comes to permits and approvals necessary for the siting of projects that assure reliable supply of natural gas. Obtaining these permits and approvals has become a time consuming and increasingly risky process that adds delay and costs to the projects that will assure adequate gas supply for the Company.

Q. Please discuss some of the operational risks faced by the Company?

A. Risks that affect the Company's operations relate to adequate delivery capability, counterparty risk, and risks related to cyber-security. The Company is also faced with counterparty risk should suppliers fail to perform their obligations, especially with regard to hedging obligations. In addition, the handling of natural gas is inherently risky. Finally, cyber-security has created increased risk when systems that deliver gas to customers are vulnerable to attack from foreign enemies and domestic terrorists.

Q. What risks are associated with the Company's infrastructure?

A. The Company's infrastructure is aging and is in the process of rehabilitation and replacement. Investments that address these issues cause costs to increase without any corresponding increase in throughput that would add to revenues.

This places pressure on the price paid by customers that may prompt them to seek alternative energy sources.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. With customer demand for the Company's service at high levels, the Company is faced with the requirement to invest in new facilities to meet growth and to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its existing facilities. The Company had 1,070 miles of its distribution mains constructed of unprotected steel and cast iron pipe as of year-end 2020. The Company also has 26,744 of its services constructed of unprotected steel. The Company is also under a regulatory mandate to relocate all of its meters outside, with certain exceptions, by September 13, 2034. The continuing costs for upgrading the Company's pipe system will elevate the level of construction expenditures. In the situation where additional capital investment is required to replace existing facilities and also to serve new customers, supportive regulation is a necessary prerequisite for the Company to actually achieve a fair rate of return and attract new capital on reasonable terms.

For the future, the Company estimates that its total construction expenditures will be:

Year	Capital Expenditures
2022	$ 475,000,000
2023	$ 499,000,000
2024	$ 493,000,000
2025	$ 493,484,000
Total	$ 1,960,484,000

Of these amounts, $1,862,535,675 are attributed to the Gas Division. During the 2022-2025 period, gross construction expenditures will represent an approximate 59% increase ($1,960,484,000 ÷ $3,331,998,000) in net utility plant, including construction work in progress, from the level at September 30, 2021.

Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. Most of the Company's residential and commercial customers use natural gas for space heating purposes. Therefore, a large proportion of the Company's residential and commercial customers present a low load factor profile and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. To help deal with this issue, UGI Gas is proposing a weather normalization adjustment ("WNA") mechanism as part of its tariff.

Q. Does your cost of equity analysis and recommendation take into account the revenue decoupling mechanism?

A. Yes. The Company is proposing a weather normalization mechanism in this case as described in the prefiled direct testimony of Company witness Mr. John D. Taylor (UGI Gas Statement No. 9). This is intended to reconcile actual weather-adjusted sales margins with those approved in the Company's most recent rate case. My cost of equity analysis takes into account the Company's WNA mechanism.

Q. How have you addressed this issue?

A. My analysis reflects the impact of the WNA on investor expectations through the use of market-determined models. All of the companies in my Gas Group have some form of WNA mechanism that is intended to accomplish the same result as the Company's proposal in this case. As a group, the market prices of these companies' common equity reflect the expectations of investors that the companies' revenues are stabilized to some extent by a WNA. Therefore, my analysis reflects the impacts of decoupling on investor expectations through the use of market-determined models.

As such, the market prices of these companies' common stocks reflect the expectations of investors related to a regulatory mechanism that adjusts revenues for conservation, abnormal weather, and other items. The trend in the industry is to stabilize the recovery of fixed costs, which are unaffected by usage. Indeed, there has been a proliferation of these mechanisms in the LDC business. Because the Gas Group that I use to measure the cost of equity has the risk attributes related to the revenue decoupling mechanism "baked in" to their stock prices, the absence of the benefit of the WNA would increase the cost of equity as determined by the models that are applied with the Gas Group data.

Q. Is the Company's risk also affected by the substantial decline in usage per customer?

A. Yes. Despite adding new customers, usage per residential heating customer continues to decline over time as is shown in UGI Gas Exhibit SAE-3 and discussed in the testimony of Ms. Sherry Epler (UGI Gas Statement No. 8).

Company analysis indicates that this decline will continue, particularly with the implementation of its successful energy efficiency and conservation plan. This plan provides many benefits to customers and to the public, but can be expected to further reduce customer usage and consequently Company revenues and return.

Q. Are you aware that there is a DSIC available to natural gas utilities in Pennsylvania, and does the DSIC affect the Company's cost of capital?

A. I am aware that the Company has utilized the Distribution System Improvement Charge ("DSIC") in the past. The cost of capital for UGI Gas, however, is not affected by the DSIC. I say this because most of the proxy group companies (i.e., eight (8) of nine (9) companies) whose data has been used to develop the cost of equity for UGI Gas in this proceeding have a DSIC or similar infrastructure rehabilitation mechanisms. Indeed, Atmos Energy, Chesapeake, New Jersey Resources, NiSource, Northwest Natural Gas, South Jersey Industries, Southwest Gas, and Spire make use of a DSIC or similar infrastructure rehabilitation mechanisms. Hence, whatever the benefit of a DSIC, or other regulatory mechanisms, that impact is already reflected in the market evidence of the cost of equity for the proxy group.

Q. How should the Commission respond to the issues facing the natural gas business and in particular UGI Gas?

A. The Commission should recognize the issues listed above when deciding the rate of return issue in this case. In particular, the Company has higher risks associated with its large throughput to industrial customers. Another risk is declining usage per customer discussed in the testimony of Company witness Ms. Sherry Epler

(UGI Gas Statement No. 8). Moreover, the Company requires regulatory support at a time of increased infrastructure spending now underway for the Company.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes, it is. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon Company risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared the Company to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. What companies comprise the Gas Group?

A. My Gas Group consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corporation, New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., South Jersey Industries, Inc., Southwest Gas Holdings, and Spire, Inc.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the credit quality ratings compare for the Company, the Gas Group, and the S&P Public Utilities?

A. Presently, the Company's Long Term ("LT") issuer credit quality rating is A2 from Moody's Investors Service ("Moody's") and A- from Fitch. The rating represents the LT issuer rating by Moody's, which focuses upon the credit quality of the issuer of the debt rather than upon the debt obligation itself. For the Gas Group, the average LT issuer rating is A3 by Moody's and A- by Standard & Poor's, as displayed on page 2 of Schedule 3. For the S&P Public Utilities, the average credit quality rating is A3 by Moody's and BBB+ by Standard & Poor's, as displayed on page 3 of Schedule 4. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for the Company, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2016-2020. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, the Company is smaller than the average size of the Gas Group, and smaller still than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for UGI Gas as compared to the Gas Group and the S&P Public Utilities.

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

There are no market ratios available for the Company because its stock is owned by UGI Corporation. The five-year average price-earnings multiple was somewhat higher for the Gas Group compared to the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio was slightly lower for the Gas Group as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common

[2]For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

equity ratios (the complement of the ratio of debt and other senior capital). A firm with a higher common equity ratio has lower financial risk, while a firm with a lower common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 56.6% for UGI Gas, 51.5% for the Gas Group, and 41.3% for the S&P Public Utilities. The Company's common equity ratio was higher than the Gas Group, thereby indicating somewhat lower financial risk. However, for the purpose of this case, the Company's common equity ratio is within the range of other gas distribution utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.120 (1.4% ÷ 11.7%) for the Company, 0.079 (0.7% ÷ 8.9%) for the Gas Group, and 0.039 (0.4% ÷ 10.3%) for the S&P Public Utilities. The variability of the Company's rates of return was considerably higher than the Gas Group and the S&P Public Utilities, thereby signifying higher risk for the Company.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[3] The five-year average operating ratios were 76.7% for the Company, 83.6% for the Gas Group, and 78.8% for the S&P Public Utilities. The Company's operating ratios were somewhat lower than the Gas Group, thereby indicating slightly lower risk.

[3]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 5.07 times for the Company, 4.05 times for the Gas Group, and 3.02 times for the S&P Public Utilities. The interest coverages were higher for the Company as compared to the Gas Group, thereby indicating lower credit risk.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. During the Pandemic, there was further pressure on cash flows due to the suspension of collection activities and the moratorium against shut off service due to nonpayment. Moreover, the Company has created a regulatory asset consisting of Pandemic related costs that the Commission has allowed to be deferred, such as excess uncollectible accounts expense and costs for an approved Emergency Relief Program. Such actions have a negative impact on the Company's cash flow. Quality of earnings has not been a significant concern for the Company, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 72.4% for the Company, 56.0% for the Gas Group, and 69.5% for the S&P Public Utilities. The Company's IGF to construction expenditures dropped in 2019 and 2020 after the reduction in the provision for deferred taxes due to the elimination of bonus depreciation.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.88 as the average for the Gas Group (see page 2 of Schedule 3) and 0.91 as the average for the S&P Public Utilities (see page 3 of Schedule 4). The systematic risk for the Gas Group as measured by the Value Line beta is fairly similar to the S&P Public Utilities.

Q. Please summarize your risk evaluation.

A. The investment risk of UGI Utilities parallels that of the Gas Group in certain respects. In certain regards, principally related to its small size, large throughput to industrial customers, and more variable earned returns, UGI Utilities has somewhat higher risk traits. UGI Utilities has lower risk as shown by its historic higher common equity ratio, its lower operating ratio, and higher interest

[4]Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

coverages. On balance, the cost of equity measured with the Gas Group data will provide a reasonable, albeit conservative, representation of the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for UGI Utilities in this case.

A. In the situation where the operating public utility raises its own long-term debt directly in the capital markets, as is the case for UGI Utilities, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. In that case, the property and earnings of the operating public utility forms the basis of the capital employed, and the capital cost rates are directly identifiable. I have employed the consolidated capital structure ratios of UGI Utilities to calculate the rate of return for this case because it finances all its operations on a consolidated basis. The circumstances of UGI Gas indicate that the capital structure ratios of UGI Utilities should be used for rate of return purposes for both its utility divisions.

Q. Does Schedule 5 provide the capitalization and capital structure ratios you have considered?

A. Yes. Schedule 5 presents UGI Utilities' capitalization and related capital structure at September 30, 2021, the end of the historic test year ("HTY"). Also shown on Schedule 5 is the UGI Utilities' capital structure estimated at September 30, 2022, the end of the future test year ("FTY"), and at September 30, 2023, the end of the FPFTY. The changes in UGI Utilities' capital structure consist of: (i) debt maturities and principal payments of $107.813 million in both the FTY and FPFTY, (ii) the issuance in three (3) series of $300 million debt issues in both the FTY and FPFTY,

(iii) the receipt of $35 million of capital contributions in the FTY, and (iv) the Company's projection of retained earnings at the end of the FTY and FPFTY.

Q. Have you made adjustments to the Company's capitalization for rate-setting purposes?

A. Yes. I have removed accumulated other comprehensive income ("OCI") from the Company's common equity account.

Q. Please explain the justification for removing the accumulated OCI?

A. The accumulated OCI must be eliminated from the capital structure for rate setting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI for the Company has its roots in the MPL and interest rate hedges associated with derivative instruments. An MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. It should be noted that the Company records the change related to prior service cost and actuarial valuations as a regulatory asset for the portion of pension attributable to its retirees and employees that are part of its regulated utility operations. The amount in the accumulated OCI is related to the portion attributable to employees of UGI Corporation and non-utility subsidiaries. That is to say, the accumulated OCI associated with MPL is not related to utility operations.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. I will adopt the UGI Utilities' capital structure ratios at the end of the FPFTY, which consists of 44.88% long-term debt and 55.12% common equity, on a rounded basis. These ratios are within the ranges indicated for the Gas Group. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

Q. Have you included short-term debt as a component of the Company's capital structure in the case?

A. No. I have considered the issue of short-term debt, but I have rejected its use here. The Company uses short-term debt to finance non-rate base items. In reaching this conclusion, I have analyzed the 12-month average balances of short-term debt for the HTY, the FTY, and the FPFTY and compared those amounts to the Company's construction work in progress ("CWIP"). I have done this because the Company follows the FERC formula to calculate its AFUDC ("Allowance of Funds Used During Construction rate"). That formula assigns short-term debt first to CWIP, with any excess balance of CWIP receiving the Company's overall rate of return. In order to avoid double-counting the amount of short-term debt that finances CWIP, those amounts must be removed from the average short-term debt amounts for rate case purposes. That is to say, the use of short-term debt for AFUDC decreases the overall cost of construction that ultimately goes into rate base so ratepayers ultimately receive the benefit for this lower cost capital. Moreover, the Company has other assets on its balance sheet that require short-term financing such as its unrecovered environmental expenditures that are regulatory assets. The unrecovered balance of the environment remediation costs is expected to be $3.796 million at the end of the FPFTY. It is reasonable to assume that short-term debt represents the source of funds used to finance these costs that are not in the rate base. As a consequence, no amount of short-term debt can be assumed to finance the rate base in this case. In the FPFTY, the CWIP balance exceeds the average amount of short-term debt. Hence, all short-term debt is excluded from the capital structure in the FPFTY.

COST OF SENIOR CAPITAL

Q. What cost rate have you assigned to the long-term debt portion of the capital structure?

A. Consistency requires that the embedded senior capital cost rates of UGI Utilities must be used for developing a fair rate of return for the Company. It is essential that the cost rate of long-term debt is related to the same proportion of senior capital employed to arrive at the capital structure ratios. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that UGI Utilities has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of long-term debt at September 30, 2021. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2022. And on page 3 of Schedule 6, the embedded cost of long-term debt is shown for the FPFTY. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 4 of Schedule 6. The cost rate, or yield to maturity, is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond.

The interest rates for the three (3) new issues of debt in the FTY and FPFTY are 3.687% for the 30-year issue in May 2022, 1.410% for the 5-year issue in July 2022, and 3.791% for the 30-year issue in October 2022. With these rates, I calculate a 3.98% forecast embedded long-term debt cost rate at September 30, 2023, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5, which provides the basis for the 44.88% long-term debt ratio.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among UGI Gas, the Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of 11.20%, including a provision for recognition of exemplary management performance.

DISCOUNTED CASH FLOW

Q. Please describe the DCF model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[5] My DCF results are provided on Schedule 1, page 2, for the Gas Group. The DCF return is 11.21% with the leverage adjustment and 10.26% without the leverage adjustment for the Gas Group. The leverage adjustment is discussed more fully below.

Among the limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility. Other limitations of the DCF include the constant price-earnings multiple assertion that does not conform with actual stock market performance. And,

[5] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

indeed, the FERC has moved to using multiple methods for measuring the cost of equity close due to the limitations of the DCF.

Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve (12) months ended September 2021, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two (2) to three (3) weeks prior to the actual payment).

For the twelve (12) months ended September 2021, the average dividend yield was 3.49% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.39% and 3.51%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.39% for the Gas Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three (3) different, but generally accepted, manners and used the average of the three (3) adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds twelve (12) basis points to the six-month average historical yield, thus producing the 3.51% adjusted dividend yield for the Gas Group.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the price-earnings multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value, and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth ("b x r"), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a “transition” stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the “transition” stage, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or “steady-state” stage is reached when a firm’s earnings growth, payout ratio, and return on equity stabilize at levels where they remain for the life of a firm. The three (3) stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three (3) stages of growth can be envisioned for a firm, the third “steady-state” growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three (3) stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle, but rather to rely upon analysts’ growth forecasts, which are those used by investors when pricing common stocks.

Q. How did you determine an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

Q. What data for the Gas Group have you considered in your growth rate analysis?

A. I considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant price-earnings multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates were obtained from the Value Line publication that provides this data. While historical data cannot be ignored, it is much less significant in applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double counted because they are already factored into analysts' forecasts of earnings growth.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the price-earnings ("P-E") multiple. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research focuses also on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five (5) years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points in order to make informed decisions to purchase and sell stocks.

Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell, and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Gas Group are also included on Schedule 9.

Q. What are the projected growth rates published by the sources you discussed?

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (5.41%), Zacks (5.88%), and Value Line (7.61%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While a variety of factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Myron Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[6] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts shown on Schedule 9 for the Gas Group exhibit a range of average earnings per share growth rates from 5.41% to 7.61%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.75% is a reasonable estimate of investor-expected growth for the Gas Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates and is below the midpoint of that data set. The reasonableness of this growth rate is also supported by the expected continuation of gas utility infrastructure spending.

Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Gas Group, average capital structure ratios are 43.49% long-term debt, 0.46% preferred stock, and 56.06% common equity, as shown on Schedule 10. If

[6] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M,"[7] provides a return of 7.52% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure

[7] Franco Modigliani and Merton H. Miller, The Cost of Capital, Corporation Finance, and the Theory of Investments, American Economic Review, June 1958, at 261-297. Franco Modigliani and Merton H. Miller, Taxes and the Cost of Capital: A Correction, American Economic Review, June 1963, at 433-443.

that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they actually existed.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true: when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I expressed my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 7.52%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 3.67% to compensate investors for the risk of a 51.07% debt ratio and 0.02% for a 0.54% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts sum to 11.21% (7.52% + 3.67% + 0.02%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 3.51% dividend yield, the 6.75% growth rate, and 0.95% for the leverage adjustment in order to arrive at the same 11.21% (3.51% + 6.75% + 0.95%) return. I know of no means to mathematically solve for the 0.95% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.95% adjustment is merely a convenient way to compare the 11.21% return computed using the Modigliani & Miller formulas to the 10.26% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF shown on Schedule 7, page 1) based on a market-value capital structure. An 11.21% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield (D_{1}/P_{0}) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 11.21%, computed as follows:

	D_1/P_0	+	*g*	+	*lev.*	=	*k*
Gas Group	3.51%	+	6.75%	+	0.95%	=	11.21%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on Schedule 1, page 2. That result is 10.50%.

Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 3.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule 11, page 1. For the twelve (12) months ended September 2021, the average monthly yield on Moody's index of A-rated public utility bonds was 3.06%. For the six- and three-month periods ended December 2020, the yields were 3.11% and 2.95%, respectively. During the twelve (12) months ended September 2021, the range of the yields on A-rated public utility bonds was 2.77% to 3.44%. Page 2 of Schedule 11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.09% on a twelve-month average basis, 1.01% on a six-month average basis, and 1.02% on a three-month average basis. Giving greater emphasis to the six-month average spread, 1.00% represents a reasonable spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on October 1, 2021, and a yield spread of 1.00%, derived from historical data.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2021	Fourth	2.9%	3.6%	2.2%	1.25%	3.45%
2022	First	3.0%	3.8%	2.3%	1.25%	3.55%
2022	Second	3.1%	4.0%	2.4%	1.25%	3.65%
2022	Third	3.2%	4.1%	2.5%	1.25%	3.75%
2022	Fourth	3.3%	4.2%	2.6%	1.25%	3.85%
2023	First	3.4%	4.3%	2.7%	1.25%	3.95%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1, 2021 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2023-2027	4.3%	5.3%	3.5%
2028-2032	4.8%	5.8%	3.9%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.75% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon such data to make investment decisions. Later FOMC pronouncements have moved the forecasts of interest rates to higher levels.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2021 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline, and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on Attachment 12, page 1.

Common Equity Risk Premiums	
Low Interest Rates	6.63%
Average Across All Interest Rates	5.67%
High Interest Rates	4.69%

Based on my analysis of the historical data, the equity risk premium was 6.63% when the marginal cost of long-term government bonds was low (i.e., 2.85%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.09% on average during periods of high interest rates), the spread narrowed to 4.69%. Over the entire spectrum of interest rates, the equity risk premium was 5.67% when the average government bond yield was 4.95%. I have utilized a 6.75% equity risk premium. The equity risk premium of 6.75% that I employed is near the risk premiums associated with low interest rates.

Q. What common equity cost rate did you determine based on your Risk Premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

	i	**+**	***RP***	**=**	***k***
Gas Group	3.75%	+	6.75%	=	10.50%

CAPITAL ASSET PRICING MODEL

Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 13.55% for the Gas Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 12.38% (13.55% - (0.12 x 9.78%)). To compute the cost of equity with the CAPM, three (3) components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.88 for the Gas Group.

Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The betas must be reflective of the financial risk associated with the ratemaking capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[8] as follows:

$$\beta l = \beta u \, [1 + (1 - t) \, D/E + P/E]$$

ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.54 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada," who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.00 for the book value capital structure of the Gas Group.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve (12) months ended September 2021, the average yield on 30-year Treasury bonds was 1.97%. For the six- and three-months ended September 2021, the yields on 30-year Treasury bonds were 2.10% and 1.93%, respectively. During the twelve (12) months ended September 2021, the range of the yields on 30-year Treasury bonds was 1.57% to 2.34%. The low yields that existed during recent periods can be traced to weakness in business fixed investment and exports due in part to the trade dispute between the United States

[8] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks;" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp. 435-452.

and China. Thereafter, extraordinary events associated with the Pandemic induced significant turmoil that jolted the capital markets in the February-May 2020 time frame. During this period, we saw abrupt reaction to the Pandemic. These events led to the end of the record-setting 128-month economic expansion. As the recession unfolded in February 2020, the FOMC acted to address these disruptions. The FOMC continues to support the money and capital markets during the recovery from the COVID-19 Pandemic. Presently, the Fed Funds rate is near zero. It is expected that a transition in FOMC policy will prospectively produce higher interest rates as the Pandemic nears its end. A forward-looking assessment of the capital markets is especially relevant now because the Company's rates will be based on financial conditions in 2022 and beyond. Higher inflation expectations are a contributing factor that points to higher interest rates. Indeed, higher inflation today is revealed by a 5.9% increase in social security payments announced on October 13, 2021, which is the largest one-year increase in nearly four (4) decades. FOMC has signaled that it plans to taper its bond buying program (i.e., quantitative easing) in November 2021 and to end it completely by March 2022. The Fed Funds rate is also likely to increase from very low levels that existed during the Pandemic. Higher interest rates clearly point to higher capital costs prospectively. I will describe the forecasts of interest below, including the end of quantitative easing by the FOMC and indications prospectively of several increases in the Fed Funds rate in 2022.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on October 1, 2021indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.2% to 2.7% during the next six (6) quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.5% from 2023 through 2027 and 3.9% from 2028 to 2032. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 2.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on Schedule 13, page 2, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule 12, page 1. On that schedule, the market return was 12.06% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.85% when interest rates were low. As such, I carried over to Schedule 13, page 2, the average large common stock returns of 12.06% and the average yield on long-term government bonds of 2.85%. The resulting market premium is 9.21% (12.06% - 2.85%) based on historical data, as shown on Schedule 13, page 2. As also shown on Schedule 13, page 2, I calculated the forecast returns, which show a 13.10% total market return. With this forecast, I calculated a market premium of 10.35% (13.10% - 2.75%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 9.78% (10.35% + 9.21% = 19.56% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms. Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns;" The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled “Equity and the Small-Stock Effect,” it was demonstrated that the CAPM could understate the cost of equity significantly according to a company’s size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. As noted previously, UGI Gas is relatively smaller than the Gas Group. To recognize this fact, I used the mid-cap adjustment of 1.02%, as revealed on page 3 of Schedule 13, for the CAPM calculation.

Q. What does your CAPM analysis show?

A. Using the 2.75% risk-free rate of return, the leverage adjusted beta of 1.00 for the Gas Group, the 9.78% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	**+**	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	**=**	***k***
Gas Group	2.75%	+	1.00	x (	9.78%	) +	1.02%	=	13.55%

<u>COMPARABLE EARNINGS APPROACH</u>

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risks characteristics would need to realize in order to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two (2) avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six (6) categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on Schedule 14, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on Schedule 14, page 2, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five (5) historical years and five (5) projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.5% using only the returns that were less than 20%, as shown on Schedule 14, page 2. The average forecasted rate of return as published by Value Line is 12.9% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data, my Comparable Earnings result is 12.70%, as shown on Schedule 1, page 2.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 11.20% for UGI Gas, which includes 20 basis points or 0.20% for recognition of the Company's strong management performance. My cost of equity recommendation is within the range of results and should be considered in the context of the Company's greater risk characteristics relative to the barometer group companies. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In summary, the Company should be provided an opportunity to realize an 11.20% rate of return on common equity so that it can compete in the capital markets, attain reasonable credit quality, sustain its cash flow in the context of its high levels of capital expenditures, and receive recognition of the significant accomplishments that management has achieved.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-one years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of

Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Commission of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

UGI GAS STATEMENT NO. 7

NICOLE M. MCKINNEY

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 7

Direct Testimony of
Nicole M. McKinney

Topics Addressed: **Taxes and Tax Adjustments**
Employee Retention Credit ("ERC")

Dated: January 28, 2022

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Nicole M. McKinney. My business address is One UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. Through December 6, 2021, I was employed by UGI Utilities, Inc. ("UGI") as Senior Manager Natural Gas Tax Accounting. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI's Gas Division ("UGI Gas" or the "Company") and Electric Division ("UGI Electric") are regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC"). On December 6, 2021, I transitioned to the role of Director of Financial Planning and Analysis at UGI Corp. For purposes of this rate case proceeding, I continued my former duties as Senior Manager Natural Gas Tax Accounting.

Q. What were your principal duties and responsibilities as Senior Manager of Natural Gas Tax Accounting?

A. My primary duties as Senior Manager Natural Gas Tax Accounting included the preparation of tax data to be reported in UGI's various United States Securities and Exchange Commission and regulatory filings, as well as its various federal and state income and non-income tax return related filings. Additionally, I maintained the current and deferred income tax accruals and expense accounts, performed tax research, and assisted UGI with tax matters as they arose. Additionally, I managed the reporting of the Company's various tax filings with its local, state, and federal jurisdictions.

Q. What are your current principal duties and responsibilities as Director of Financial Planning and Analysis?

A. In this role, I provide strategic and operational direction for UGI's processes and functions related to financial planning and analysis. My budget supervision responsibilities include the: 1) coordination and review of financial inputs from various departments; 2) development of financial forecasts; and 3) preparation and distribution of this information to UGI executive management, investor relations, and the UGI Board of Directors. Additionally, I oversee capital investment processes, manage corporate finance projects, and report directly to the Chief Finance Officer.

Q. Please describe your educational background and professional experience.

A. They are set forth in my resume attached as UGI Gas Exhibit NMM-1.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Gas. I will explain the Company's *pro forma* tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2023 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Gas's historic test year ended September 30, 2021 ("HTY") and future test year ending September 30, 2022 ("FTY").

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit NMM-1 contains a list of those proceedings.

Q. Ms. McKinney, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the UGI Gas Exhibits: NMM-1, NMM-2, NMM-3 and NMM-4. Together with other Company witnesses, I am sponsoring portions of UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) that pertain to tax-related issues. These exhibits comprise UGI Gas's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing requirements and standard data requests. Each response identifies the witness sponsoring it.

II. TAX ADJUSTMENTS

Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to the proposed tax adjustments.

A. As explained in the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2), UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2023. Section D of UGI Gas Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Gas Exhibit A (Historic) and UGI Gas Exhibit A (Future) follow the format of UGI Gas Exhibit A (Fully Projected) but reflect data for the HTY ended September 30, 2021 and the FTY ending September 30, 2022. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing UGI Gas's FPFTY claims with actual book results from the HTY and adjusted FTY results. Section

D to UGI Gas Exhibit A (Historic), Schedule D-31, and UGI Gas Exhibit A (Future), Schedule D-31, include adjustments that share the same methodology as used in Schedule D-31 of UGI Gas Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

Q. How was the provision for taxes-other-than-income taxes ("TOTI") determined for the FPFTY?

A. TOTI consists of the Pennsylvania Utility Realty Tax ("PURTA"), Pennsylvania and Local Property taxes, Social Security taxes, Federal Unemployment tax ("FUTA"), State Unemployment tax ("SUTA") and the Company's assessed contribution to the Commission, Office of Consumer Advocate and Office of Small Business Advocate. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as supported by the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2). These adjustments are shown on UGI Gas Exhibit A (Fully Projected), Schedule D-31. The net adjustment of $298,000 is brought forward to Schedule D-3, page 2.

B. INCOME TAXES

Q. Please discuss the Company's claim for income taxes.

A. Income tax expense for the FPFTY at present and proposed rates is set forth in UGI Gas Exhibit A (Fully Projected), Schedule D-33. Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of federal income taxes, and the flow-through of accelerated depreciation benefits for state tax purposes. UGI Gas is continuing its practice of normalizing the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Gas continues to flow through the repairs tax benefit over the tax useful lives of the asset that generated the benefit, which is generally 20 years. The fully adjusted claim for the FPFTY income tax expense is shown on UGI Gas Exhibit A (Fully Projected), Schedule D-1.

Q. Please describe the claim for income taxes shown on Schedule D-1, lines 19 and 20.

A. The calculation of federal and state income taxes can be found on Schedule D-33, lines 13 and 19. Schedule D-33 shows the calculation of *pro forma* income taxes for the FPFTY at present and proposed rates. Line 1 shows revenue at present and proposed rates, while line 2 shows operating expenses at present and proposed rates from Schedule D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1 from line 2. Debt interest expense is synchronized using the rate base claim from Schedule C-1, with the cost of debt and the debt component of UGI Gas's capital structure recommended in the direct testimony of Paul R. Moul (UGI Gas Statement No. 6) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from net income before debt interest to calculate base taxable income on line 7.

In accordance with established Commission practice, lines 8 through 11 of Schedule D-33 reduce the base taxable income, for state tax purposes, by the total difference between accelerated tax depreciation shown on line 8 and the *pro forma* book depreciation shown on line 9. The statutory state corporate net income tax rate (9.99%) was then applied to determine the *pro forma* state income tax expense shown on line 13. Lines 14 through 19 show the federal income tax expense calculation at current and proposed rates, while line 20 sums the state and federal tax expense amounts before application of Deferred Federal and State Income Taxes. At lines 21 through 28, Deferred Federal and State Income Taxes are used to increase the *pro forma* income tax expense at present and proposed rates with the total calculated amount for income taxes before the application of other adjustments shown on line 29. The amounts of accelerated depreciation, cost of removal, repairs tax deduction, tax basis adjustments to plant, straight line depreciation and book depreciation used in the determination of income taxes are summarized on Schedule D-34.

Q. What is the total FPFTY income tax expense for UGI Gas?

A. As shown on Schedule D-33 at line 31, the *pro forma* tax expense at present rates is $39.8 million and the *pro forma* tax expense at proposed rates for the FPFTY is $63.3 million. As explained below in Section G, this figure is not reduced by a consolidated income tax adjustment.

Q. Has the Company reflected the amortization of Excess Deferred Federal Income Taxes ("EDFIT"), as a result of the 2017 Tax Cuts and Jobs Act ("TCJA"), on its income tax expense claim?

A. Yes, the Company has calculated the amount of the EDFIT that would be amortized and flowed back to ratepayers in its FPFTY. This amount is included in the overall federal deferred tax expense calculated on Line 25 of Schedule D-33. The total amortization was approximately $4.3 million, calculated using the Average Rate Assumption Method ("ARAM") as required by tax normalization rules.

C. ACCUMULATED DEFERRED INCOME TAXES

Q. How are Accumulated Deferred Income Taxes ("ADIT") calculated?

A. Schedule C-6 shows the FPFTY ending balance for federal ADIT as of September 30, 2023. This amount is deducted from rate base. The total shown on line 8 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation and straight-line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base was further reduced by the state regulatory liability associated with UGI Gas's repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

Q. What is the amount of the ADIT offset to rate base?

A. As shown on line 8 of Schedule C-6 and on line 6 of Schedule A-1, the ADIT offset is $628.5 million, which includes the amount related to EDFIT.

Q. Does the Company's reduction to rate base include EDFIT?

A. Yes, the Company has reduced its rate base by the unamortized EDFIT, which is incorporated in the ADIT balance on Line 8 of Schedule C-6.

Q. Has the Company's ADIT rate base deduction been calculated in compliance with the normalization requirements of the Internal Revenue Code?

A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes to comply with IRS normalization requirements. To qualify for normalization, the IRS requires utilities to pro-rate rate base deductions for ADIT to account for the fact that the Company accrues ADIT for plant additions throughout the year. See UGI Gas Exhibit NMM-2 for the calculation of the pro-rata adjustment.

D. REPAIRS TAX METHOD

Q. Please explain UGI Gas's accounting treatment of the Repairs Tax Method.

A. In its tax return for the year ended September 30, 2009, UGI Gas adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. As it did in the Company's previous base rate case at Docket No. R-2019-3015162, UGI Gas has chosen to normalize its federal income tax expense claim, inclusive of the repairs tax deduction. The difference between accelerated tax depreciation versus book depreciation in the calculation of federal tax expense creates ADIT. For state income tax purposes, solely with respect to the repairs tax deduction, UGI Gas has chosen to flow through the repairs tax benefit over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers have not yet received. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset.

As noted previously, the Company reduces rate base by the sum of the federal ADIT balance and the state repair regulatory liability.

E. CONSOLIDATED TAX BENEFITS

Q. Does the Company's proposed revenue requirement reflect a federal consolidated tax expense adjustment?

A. No. The Company's revenue requirement is established based on its stand-alone federal income tax attributes. It is my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, eliminates the need to show a consolidated tax adjustment for ratemaking purposes. However, Section 1301.1(b) requires a public utility to demonstrate that it shall use at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent shall be used for general corporate purposes.

A calculation of the consolidated tax adjustment for that purpose, using the modified effective tax rate methodology traditionally used by the Commission prior to the enactment of Act 40, is included in the Company's filing as Attachment II-A-26 and UGI Gas Exhibit NMM-3. Company witness Ms. Tracy A. Hazenstab (UGI Gas Statement No. 2) discusses how the Company has satisfied the requirements of Act 40.

F. EMPLOYEE RETENTION CREDIT

Q. Are you familiar with the settlement of the Company's last Natural Gas Base Rate Case at Docket No. R-2019-3015162, et al. and its requirement that UGI Gas report tax credits related to the Coronavirus Aid, Relief, and Economic Security ("CARES") Act?

A. Yes. Ordering Paragraph 32 in the Commission's Order approving the Settlement (entered October 8, 2020) stated:

That the Company shall provide a report as part of the Company's next base rate case detailing: (1) its efforts to maximize its utilization of and track any government benefits, whether direct grant, tax credits, or other, to minimize costs to be deferred; (2) any amounts obtained as part of these efforts and their intended use; and, (3) if denied, the reason for such denial.

Q. Did UGI Gas receive any tax credit as a result the CARES Act?

A. Yes. Pursuant to Section 2301 of the CARES Act, UGI Gas received approximately $1.5 million in Employee Retention Credits ("ERC"), which it applied against the payroll tax deferral allowed under Section 2302 of the CARES Act. See UGI Gas Exhibit NMM-4 for a report containing further details on all tax benefits obtained from the CARES Act and other initiatives the Company pursued per Ordering Paragraph 32 in the settlement of the 2019 UGI Gas Base Rate Case at Docket No. R-2019-3015162.

Q Does the Company intend to return any of the ERC tax benefits to customers?

A. No. The Company does not intend to return the ERC tax benefits to customers since the tax credits relate to costs, primarily payroll, that were incurred outside of the test year periods. Specifically, the ERC relates to payroll costs incurred after March 12, 2020 and before January 1, 2021.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT NMM-1

Nicole M. McKinney, CPA

460 N. Gulph Road
King of Prussia, PA 19406

mckinneyn@ugicorp.com
(484) 877-7601

PROFESSIONAL EXPERIENCE:

UGI Corporation. King of Prussia, PA
Director – FP&A. December 2021 – Present
- Supervise 2 reports
- Manage the monthly forecast cycle and annual budget cycle
- Monitor and review various management financial reports
- Support analysis of business development opportunities
- Oversee UGI's investment policy

UGI Utilities, Inc. Denver, PA
Sr. Manager of Natural Gas Tax Accounting. March 2015 – Present
- Supervise 2 reports
- Manage the accounting for income taxes in accordance with ASC 740 for Natural Gas business segment
- Provide technical accounting guidance and expertise on tax accounting, planning and compliance matters
- Oversee and review the preparation of various tax related filings

DENTSPLY International. York, PA
Manager. August 2012 –April 2014
- Supervised staff of 3
- Responsible for identifying deficiencies and areas of improvement for current tax and accounting processes
- Managed completion of domestic federal tax returns and income tax provision
- Performed periodic presentations to senior management regarding tax implications of various business transactions and changes in tax law
- Supervised special tax projects such as research & development tax credit study, domestic production activities deduction, and accounting method changes

ParenteBeard, LLC. Lancaster, PA
Manager. December 2010 – July 2012.
- Supervised staff of 5
- Managed client relationships for middle-market businesses to ensure satisfaction of tax and accounting needs
- Assisted in the standardization of accounting processes and working papers
- Served as the liaison between external auditors and clients to achieve efficiency and successful results in year- end audits
- Reviewed complex individual, partnership, corporate, and international federal and state tax returns
- Served as manager on the strategic tax initiative team

WTAS, LLC. Philadelphia, PA
Manager. August 2006 – November 2010.
- Supervised staff of 3+
- Managed successful consulting engagements resulting in substantial cash savings

- Developed various complex financial models for client budgetary and forecasting needs
- Prepared and reviewed various international, domestic, and state corporate and partnership tax returns

EDUCATION:
Villanova University, Villanova, PA
Master of Accountancy - May 2007
Bachelor of Science - International Business/Management & Accounting - May 2006
Summa cum Laude
Bartley Medallion of Honor

Previous Testimony:

UGI Electric Base Rate Case	Docket No. R-2021-3023618
UGI Gas Base Rate Case:	Docket No. R-2019-3015162
UGI Gas Base Rate Case:	Docket No. R-2018-3006814
UGI Electric Base Rate Case:	Docket No. R-2017-2640058
UGI Penn Natural Gas, Inc. Rate Case:	Docket No. R-2016-2580030
UGI Utilities, Inc. – Gas Division Rate Case:	Docket No. R-2015-2518438

UGI GAS

EXHIBIT NMM-2

UGI Utilities, Inc. - Gas Division
Calculation of Pro-Rata Accumulated Deferred Income Tax
(In Thousands)

Month	A Increase to Deferred Taxes	B # of Days	C = B/365 Pro-Rata %	D = C*A Pro-Rata Incr to Deferred Taxes	Per Treas. Reg.1.167(l)-1(h)(6)(ii) Accumulated Deferred Income Tax Balance
9/30/2022					$ 620,598
10/31/2022	829	335	91.78%	761	621,359
11/30/2022	1,244	305	83.56%	1,039	622,399
12/31/2022	2,281	274	75.07%	1,712	624,111
1/31/2023	2,073	243	66.58%	1,380	625,491
2/28/2023	1,037	215	58.90%	611	626,101
3/31/2023	1,037	184	50.41%	523	626,624
4/30/2023	1,244	154	42.19%	525	627,149
5/31/2023	1,244	123	33.70%	419	627,568
6/30/2023	1,244	93	25.48%	317	627,885
7/31/2023	2,073	62	16.99%	352	628,237
8/31/2023	3,110	31	8.49%	264	628,501
9/30/2023	3,317	1	0.27%	9	**$ 628,510**

UGI GAS

EXHIBIT NMM-3

UGI Utilities, Inc. - Gas Division
Calculation of Consolidated Tax Adjustment
For the Years Ended September 30, 2018, 2019 and 2020
(thousands of dollars)

	Taxable Income 2018	Taxable Income 2019	Taxable Income 2020	Average	% of Total	CTA
Tax Loss Entities						
Ashtola Production Company	(1)	(1)	(1)	(1)		
Homestead Holding	(155)	(273)	(607)	(345)		
UGI Hunlock Dev	(90)	0	0	(30)		
UGI HVAC Enterprises	(893)	(305)	0	(399)		
UGID Holding Company	(7)	(8)	(8)	(8)		
United Valley Insurance	(239)	(751)	0	(330)		
UGI Corporation	0	0	(147,867)	(49,289)		
AmeriGas Inc	(26)	(26)	(23)	(25)		
AmeriGas Propane Holdings, Inc.	0	0	0	0		
UGI Penn HVAC Services	(16)	0	0	(5)		
UGI Properties, Inc.	(99)	0	0	(33)		
UGI Utilities, Inc.	0	0	0	0		
UGI Enterprises Inc	0	0	0	0		
UGI Development Company	0	(5,924)	(4,961)	(3,628)		
Subtotal Taxable Loss	(1,525)	(7,286)	(153,467)	(54,093)		
Tax Positive Entities						
AmeriGas Propane Inc.	61,224	93,880	56,320	70,475	39.9%	(21,601)
AmeriGas Inc.	0	0	0	0	0.0%	0
AmeriGas Propane Holdings, Inc.	0	90	3,842	1,311	0.7%	(402)
Amerigas Technology Group Inc.	0	0	0	0	0.0%	0
Energy Service Funding	4,782	5,062	3,479	4,441	2.5%	(1,361)
Newberry Holding	2,660	3,253	955	2,290	1.3%	(702)
Petrolane Incorporated	0	0	0	0	0.0%	0
UGI China, Inc.	0	0	0	0	0.0%	0
UGI Corporation	27,142	37,610	0	21,584	12.2%	(6,616)
UGI Development Company	1,259	0	0	420	0.2%	(129)
UGI Enterprises, Inc.	0	0	0	0	0.0%	0
UGI Europe, Inc.	5,218	35,767	22,795	21,260	12.0%	(6,516)
UGI HVAC Enterprises	0	0	4,824	1,608	0.9%	(493)
UGI LNG	4,792	5,530	2,318	4,214	2.4%	(1,291)
UGI Penn HVAC Services	0	3	0	1	0.0%	(0)
UGI Properties, Inc.	0	245	349	198	0.1%	(61)
UGI Storage Company	5,903	4,465	4,152	4,840	2.7%	(1,483)
UGI Utilities, Inc.[2]	0	57,929	73,276	43,735	24.8%	(13,405)
UGI International Enterprises, Inc.	0	0	0	0	0.0%	0
United Valley Insurance	0	0	323	108	0.1%	(33)
Eliminations	0	0	0	0	0.0%	0
Subtotal Taxable Income	112,979	243,833	172,634	176,482	100.0%	(54,093)
Total Taxable Income	111,454	236,547	19,167	122,389		

Tax Savings Applicable to UGI Utilities, Inc.	(13,405)
MWF Allocation % for UGI Gas	90.69%
Total Tax Savings Allocated to UGI Gas	(12,157)
Federal Tax Rate	21%
Total Consolidated Tax Adjustment	**(2,553)**

Notes:

1. Single-member limited liability companies, i.e. disregarded entities, have been combined with their tax-regarded parent company.

2. As of October 1, 2018, UGI Penn Natural Gas, Inc. (f/ka/ "PNG") and UGI Central Penn Gas Inc. (f/k/a "CPG") merged into UGI Utilities, Inc. - Gas Division. As such, the Company's consolidated taxable income is reflected above.

Tax Loss Entities	Taxable Income 2020	Adjustments		Adjusted Taxable Income
UGI Corporation	(201,320)	53,453	(1)	(147,867)
AmeriGas Inc	(23)			(23)
AmeriGas Propane Holdings, Inc.	(207,170)	211,012	(2)	3,842
Amerigas Technology Group Inc.	0			0
Ashtola Production Company	(1)			(1)
Eastfield International Holdings Inc	0			0
EuroGas Holdings Inc.	0			0
Four Flags Drilling Company	0			0
Hellertown Pipeline	0			0
Homestead Holding	(607)			(607)
UGI Asset Management	0			0
UGI Black Sea Enterprises	0			0
UGI Development Company	(16,858)	11,897	(3)	(4,961)
UGI Energy Ventures, Inc.	0			0
UGI Ethanol Development Company	0			0
UGI Enterprises Inc	0			0
UGI Hunlock Dev	0			0
UGI HVAC Enterprises	0			0
UGI International China. Inc	0			0
UGI International (Romania)	0			0
UGI Penn HVAC Services	0			0
UGI Petroleum Products of DE	0			0
UGI Romania, Inc.	0			0
UGID Holding Company	(8)			(8)
Total Tax Loss	(425,987)	276,362		(149,625)

Explanations of Adjustments:

(1) UGI Corporation adjustment relates to bonus depreciation taken on non-utility fixed assets for a one-time acquistion.

(2) AmeriGas adjustment relates to one-time adjustment for entity restructuring.

(3) UGI Development adjustment relates to one-time sale of non-utility fixed assets and partnership interest.

Tax Loss Entities	Taxable Income 2019	Adjustments	Adjusted Taxable Income
UGI Corporation	-		0
AmeriGas Inc	(26)		(26)
Amerigas Technology Group Inc.	-		0
Ashtola Production Company	(1)		(1)
Eastfield International Holdings Inc	-		0
EuroGas Holdings Inc.	-		0
Four Flags Drilling Company	(0)		(0)
Hellertown Pipeline	-		0
Homestead Holding	(273)		(273)
UGI Asset Management	(0)		(0)
UGI Black Sea Enterprises	-		0
UGI China Inc	-		0
UGI Development Company	(5,924)		(5,924)
UGI Energy Ventures, Inc.	-		0
UGI Ethanol Development Company	-		0
UGI Hunlock Dev	-		0
UGI HVAC Enterprises	(305)		(305)
UGI International China. Inc	-		0
UGI International (Romania)	-		0
UGI LNG	-		0
UGI Penn HVAC Services	-		0
UGI Petroleum Products of DE	(0)		(0)
UGI Romania, Inc.	-		0
UGID Holding Company	(8)		(8)
United Valley Insurance	(751)		(751)
Total Tax Loss	(7,287)	0	(7,287)

	Taxable Income 2018	Adjustments	Adjusted Taxable Income
Tax Loss Entities			
UGI Corporation	0		0
AmeriGas Inc	(26)		(26)
Amerigas Technology Group Inc.	0		0
Ashtola Production Company	(1)		(1)
Eastfield International Holdings Inc	0		0
EuroGas Holdings Inc.	0		0
Four Flags Drilling Company	0		0
Hellertown Pipeline	0		0
Homestead Holding	(155)		(155)
UGI Asset Management	(0)		(0)
UGI Black Sea Enterprises	0		0
UGI Properties, Inc.	(99)		(99)
UGI Penn Natural Gas, Inc.	0		0
UGI Enterprises Inc	0		0
UGI Hunlock Dev	(90)		(90)
UGI HVAC Enterprises	(893)		(893)
UGI International China. Inc	0		0
UGI International (Romania)	0		0
UGI Penn HVAC Services	(16)		(16)
UGI Utilities, Inc.	0		0
United Valley Insurance	(239)		(239)
UGID Holding Company	(7)		(7)
Total Tax Loss	(1,525)	0	(1,525)

UGI GAS

EXHIBIT NMM-4

Report of Amounts Obtained from Government Benefits per Ordering Paragraph 32 in the Commission's Order on the Settlement of the 2019 UGI Gas Base Rate Case at Docket No. R-2019-3015162

1. **<u>Employee Retention Credit ("ERC")</u>**
   Section 2301 of the CARES Act allowed qualifying employers to claim a credit against the employer portion of applicable employment taxes for wages paid after March 12, 2020 and before January 1, 2021 for each calendar quarter in an amount equal to 50-percent of qualified wages, including allocable qualified health expenses, with respect to each employee. For the time period claimed by the Company, the ERC could not exceed $5,000 per employee. UGI Gas claimed an approximate ERC tax benefit of $1.5 million. The Company utilized an outside accounting firm to assist it in determining its eligibility for the tax credit as well as in reviewing its process and calculation for quantifying the credit. UGI Gas worked with its third-party payroll processor to file the applicable IRS forms (i.e. 941 and 941X) to claim the ERC tax benefits.

2. **<u>Payroll Tax Deferral</u>**
   Section 2302 of the CARES Act allowed employers to defer the deposit and payment of the employer's portion of Social Security taxes and certain railroad retirement taxes for the period March 27, 2020 through December 31, 2020. The Company chose to defer the payments allowed under the CARES Act. The first payment of 50% of the total deferred amount was due by December 31, 2021, and the Company timely made this payment. The other 50% payment is due by December 31, 2022. UGI Gas is working with its third-party payroll processor to quantify and remit the deferred amounts. Further, in discussions with its payroll processor, the Company was advised that the IRS would apply any ERC benefit claimed against the deferred amounts.

3. **<u>Families First Coronavirus Response Act ("FFCRA")</u>**
   The FFCRA provided small and midsize employers refundable tax credits which reimbursed them, dollar-for-dollar, for the cost of providing paid sick and family leave wages to employees for leave related to COVID-19. Only employers with fewer than 500 employees were eligible for these tax credits. Due to exceeding the allowable number of employees, UGI Gas did not qualify for these tax credits. As such, the Company did not claim any FFCRA tax credits.

UGI GAS STATEMENT NO. 8

SHERRY A. EPLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 8

Direct Testimony of
Sherry A. Epler

Topics Addressed:	**Test Year Sales and Revenues** **Revenue Allocation and Rate Design** **Tariff Changes**

Dated: January 28, 2022

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

Q. By whom and in what capacity are you employed?

A. I am employed as Senior Manager, Tariff & Supplier Administration, by UGI Utilities, Inc. ("UGI"). UGI has both a Gas Division ("UGI Gas"), which is a certificated natural gas distribution company ("NGDC"), and an Electric Division ("UGI Electric"), a certificated electric distribution company ("EDC").

Q. What are your responsibilities as Senior Manager, Tariff & Supplier Administration with respect to UGI Gas?

A. My current responsibilities related to UGI Gas include: (1) all aspects of tariff and rate administration for UGI Gas, including interactions with natural gas suppliers under UGI Gas's supplier tariff; and (2) revenue analysis.

Q. Please provide your educational background.

A. Please see my resume, UGI Gas Exhibit SAE-1, which is attached to my testimony.

Q. Please provide your professional experience.

A. I have worked for UGI since 1986, supporting the Accounting and Rates groups in varying capacities. Please see my resume, UGI Gas Exhibit SAE-1, for my full employment history.

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of sales and revenue for the historic test year ended September 30, 2021 ("HTY"), future test year ending September 30, 2022 ("FTY"), and fully projected future test year ending September 30, 2023 ("FPFTY"); (2) revenue allocation and rate design; and (3) certain proposed tariff modifications.

Q. Are any other witnesses providing testimony on the areas you identified above?

A. Yes. Company witness Constance E. Heppenstall, who is employed as Senior Project Manager, Rate Studies by Gannett Fleming Valuation and Rate Consultants, LLC (UGI Gas Statement No. 10), is sponsoring UGI Gas Exhibit D – Cost of Service, from which revenue allocations were derived. Ms. Heppenstall also utilizes the projected sales and revenue figures discussed in my testimony.

Q. Are you sponsoring any exhibits or filing requirements in this proceeding?

A. Yes, I am sponsoring the following Exhibits: UGI Gas Exhibit SAE-1 (Resume), UGI Gas Exhibit SAE-2 (15 year Normal Heating Degree Days), UGI Gas Exhibit SAE-3 (Normalized Multi-Year and 12-Month Ending Trends of Use Per Customer for Residential and Commercial Heating), UGI Gas Exhibit SAE-4 (Fully Projected Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-5 (Future Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-6 (Historic Test Year Sales and Revenue Adjustments), UGI Gas Exhibit SAE-7 (Fully Projected Future Test Year Usage Per Customer Detail by Class), UGI Gas Exhibit SAE-8 (No Notice Service (NNS) Rate Calculation), UGI Gas Exhibit SAE-9 (Monthly Balancing Service (MBS) Rate Calculation), UGI Gas Exhibit SAE-10 (Rider D-Merchant Function Charge (MFC)

Calculation), certain portions of UGI Gas Exhibit F (Proposed Tariff), and UGI Gas Exhibit E (Proof of Revenue). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the mater list accompanying this filing, that were prepared by me or under my direction.

II. TEST YEAR SALES AND REVENUE

Q. Please explain the process for developing the Company's Fiscal Year 2023 sales and revenue budgets.

A. The sales and revenue budgets were a joint effort of the marketing and financial planning and analysis ("FP&A") departments, with the marketing department providing customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The FP&A department developed projections for budgeted usage per customer for core customer classes, total calculated sales and total calculated revenues. In developing sales and revenues, the Vice President, Marketing and Customer Relations, with input and assistance from other marketing employees, budgets the number of customers by class. Various factors are considered in developing customer budgets, including: (1) projected conversions to and from other energy sources; (2) the level of applications and inquiries for service; (3) other customer attritions; (4) new construction activity; (5) current and projected economic factors; and (6) the costs of competing fuels. The usage per customer reflected in the 2023 budget was the same as that used for the 2022 budget and specifically does not incorporate use per customer conservation trends related to the Company's core residential and commercial class customers. Budget use per customer values were developed based on a simple regression of 24 months of actual use per customer data and then normalized based on normal heating degree days. Planned budgeted numbers of customers and usage per customer for these customer classes are then combined to produce planned budgeted sales. Sales are allocated by month, and appropriate rates are applied to derive budgeted revenues. Sales and revenues related to large contract customer classes are developed by the marketing department on a customer specific basis using customer input where appropriate. As discussed in the testimony of Tracy A. Hazenstab (UGI Gas Statement No. 2), the derivation of the 2023 planned budget reflects a forecast that will subsequently be updated during calendar year 2022 as part of the normal annual budget process. This process is conducted several months prior to the start of the new fiscal year and finalized prior to the beginning of the new fiscal year.

Q. Please explain how the Company's FPFTY sales and revenues were developed.

A. FPFTY sales and revenues were developed by annualizing and normalizing the Company's 2023 fiscal year planned sales and revenue budgets. Where similar adjustments are made across rate class groups, the methodology applied to develop normalized use per customer adjustments (for the FPFTY, FTY, and HTY) to budget values is the same for all three periods in order to present sales and revenue on a ratemaking basis. A summary of projected use per customer by class group for the FPFTY, FTY, and HTY are included in UGI Gas Exhibit SAE-7. The projected Residential Heating use per customer was established for Rate R/RT-Heating per the UGI Gas model detailed in SDR-RR-11. Since, over time, switching occurs on a regular basis between Rates R (retail service) and RT (transportation service), the regression analysis was performed on a total Rate R/RT basis in order to eliminate potential switching impacts which could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized Use/Customer." Weather normalized sales for Rate RT-Heating customers for the 12 months ended September 30, 2021, were then utilized to derive the separate Rate RT-Heating and Rate R-Heating use per customer values (from the combined Rate R/RT-Heating use per customer value).

Actual sales were normalized for Rate R-General and Rate RT-General, in total, to reflect the 12 months ended September 30, 2021. These data were used to project combined Rate R/RT-General use per customer in total. Weather normalized sales for Rate RT-General customers for the 12 months ended September 30, 2021, were then utilized to derive the separate Rate RT-General and Rate R-General customer values (from the combined Rate R/RT-General use per customer value).

The projected Commercial Heating use per customer was established on a combined total basis for Rates N/NT/DS-Heating per the UGI Gas model regression techniques detailed in SDR-RR-11. Given that, over time, switching occurs on a regular basis between Rates N (retail service), NT (transportation service) and DS (transportation service), the regression analysis was performed on a total Rates N/NT/DS basis in order to eliminate potential switching impacts that could distort use per customer analyses. More detail on this regression analysis is provided below as part of the discussion related to the Company's "Adjustment for Normalized & Annualized Use/Customer." In order to then separate the combined Rate N/NT/DS – Commercial Heating value into respective Rate N, Rate NT and Rate DS values, Rate NT – Commercial Heating use per customer was established on the basis of weather normalized sales for Rate NT-Commercial Heating customers, for the 12 months ended September 30, 2021 as this class in much smaller in number than the Rate N – Commercial Heating class. Rate DS – Commercial Heating use per customer was then established based on budgeted 2023 sales for Rate DS-Commercial Heating, as Rate DS budgeting was performed on a detailed per-customer level. These Rate NT and Rate DS commercial heating values were then utilized to mathematically derive the Rate N-Commercial Heating use per customer values (from the combined Rates N/NT/DS-Commercial Heating use per customer value).

Actual sales were normalized for Rate N-Commercial General, Rate NT-Commercial General and Rate DS-Commercial General, in total, to reflect the 12 months ended September 30, 2021, in order to project combined Rates N/NT/DS-Commercial General use per customer in total. In order to then separate the combined Rate N/NT/DS – Commercial General value into respective Rate N, Rate NT and Rate DS values, Rate NT – Commercial General was based on weather normalized sales for Rate NT-Commercial General, for the 12 months ended September 30, 2021, and Rate DS – Commercial General was based on budgeted 2023 sales for Rate DS-Commercial General, which were done on a per-customer level. These Rate NT and Rate DS values, were then utilized to mathematically derive the Rate N-Commercial General use per customer values (from the combined Rates N/NT/DS-Commercial General use per customer value).

Actual sales were normalized for Rate N-Industrial, Rate NT-Industrial, and Rate DS-Industrial to reflect the 12 months ended September 30, 2021, in order to project combined Rates N/NT/DS-Industrial use per customer in total. In order to then separate the combined Rate N/NT/DS – Industrial value into respective Rate N, Rate NT and Rate DS values, Rate NT – Industrial was based on weather normalized sales for Rate NT-Industrial for the 12 months ended September 30, 2021. Rate DS – Industrial was based on budgeted 2023 sales for Rate DS-Industrial, which were done on a per-customer level. These Rate NT and Rate DS values were then utilized to mathematically derive the Rate

N-Industrial use per customer value (from the combined Rates N/NT/DS-Industrial use per customer value).

Q. How was temperature accounted for in developing sales and revenue forecasts?

A. The Company's FPFTY sales and revenue forecasts reflect annual normal heating degree days of 5,568. This annual normal heating degree day calculation is derived from a composite sales weighted value (by system demand) of each of the Company's four delivery regions, and the respective normal heating degree values. Normal heating degree days are defined based upon an average over a 15-year period and are updated every five years; the most recent update was for the 15-year period ending December 31, 2019. UGI Gas Exhibit SAE-2 provides supporting detail by year for the 15-year normal heating degree days.

Q. Is the use of average temperature data for a 15-year period consistent with the methodology used for calculating normal heating degree days in previous UGI Gas base rate cases?

A. Yes. The Company has consistently used a 15-year period methodology in the past seven gas base rate cases that the Company or its former subsidiaries have filed (as listed below).

- UGI Central Penn Gas ("CPG") 2009 Base Rate Case, Docket No. R-2008-2079675
- UGI Penn Natural Gas ("PNG") 2009 Base Rate Case, Docket No. R-2008-2079660
- UGI CPG 2011 Base Rate Case, Docket No. R-2010-2214415
- UGI Gas 2016 Base Rate Case, Docket No. R-2015-2518438
- UGI PNG 2017 Base Rate Case, Docket R-2016-2580030
- UGI Gas 2019 Base Rate Case, Docket No. R-2018-3006814
- UGI Gas 2020 Base Rate Case, Docket No. R-2019-3015162

Q. Please describe the adjustments made to the budget for the 12 months ending September 30, 2023, to develop FPFTY sales and revenues.

A. A summary of all adjustments made to the 2023 budget in order to develop FPFTY sales and revenue is shown on UGI Gas Exhibit SAE-4(a). Detail for each of these adjustments is provided on subsequent worksheets labeled 4(b) through 4(m). In total, these adjustments reflect a decrease to sales of 1,781 MMcf and an increase to revenue of $65.690 million, inclusive of Purchased Gas Cost ("PGC") revenues.

Q. Please explain the "Adjustment for Customer/Contract Changes" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Customer/Contract Changes" annualizes customer counts to anticipated end-of-test-year levels based on the Company's most recent forecast for the FPFTY; it is inclusive of any large transportation contract customer changes related to customers served under Rates LFD, XD, and IS. In particular, among other adjustments, this adjustment includes a net increase of 411 residential heating customers (Rate R) from budgeted levels to anticipated end-of-test-year levels and a net decrease of 28 commercial heating customers (Rate N) from budgeted levels to anticipated end-of-FPFTY levels on September 30, 2023.

Q. How were these adjustments calculated?

A. UGI Gas Exhibit SAE-4(b) provides the calculation of the associated sales and revenue adjustments for the stated customer counts. In total, this adjustment decreases sales by 194 MMcf and increases projected revenues by $0.278 million, inclusive of PGC revenues. Additional detail for column (9) of UGI Gas Exhibit SAE-4(b) can be found on UGI Gas

Exhibit SAE-4(b)(1), which provides a breakout of customer data for large transportation customer classes.

Q. Please explain the adjustment titled "Adjustment for Customer/Contract Changes – Large Transport and Interruptible Detail" as shown on UGI Gas Exhibit SAE-4(b)(1).

A. The adjustments for large transportation customers were developed by UGI Gas's marketing personnel following their review of individual large customer accounts and market segments. It reflects annualizing anticipated increases or reductions from original fiscal adjustments and includes the addition of $308,000 in anticipated revenue related to the Auburn Capacity Lease, as discussed in the direct testimony of Christopher R. Brown (UGI Gas Statement No. 1).

Q. Please explain your next adjustment, "Adjustment for Normalized & Annualized Use/Customer" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Normalized & Annualized Use/Customer" normalizes and annualizes usage per customer to projected end-of-test-year levels. Specifically, in developing usage per customer projections for the Company's core Residential Heating rate groups (Rates R and RT), the Company utilized an econometric regression model that incorporates four independent variables: (1) use per customer; (2) heating degree days; (3) lagged heating degree days; and (4) weighted time trend. While use per customer, heating degree days, and lagged heating degree days capture weather related usage factors, which can then be used to project normalized and annualized customer usage under normal weather conditions, the weighted time trend variable of this regression captures non-weather trends that underlie changes in usage per customer over time (*e.g.*, conservation). These trends can vary, but as a comprehensive variable, "trend" will capture the impacts of conservation, including but not limited to: (1) regular appliance replacements; (2) accelerated appliance replacements; (3) high-efficiency appliance installations; (4) setback thermostat installations; (5) modifications to new and existing buildings that are designed to decrease energy consumption; and (6) changes in consumer usage behavior due to other economic influences. Given the number of variables that can influence customer usage over time, and the difficulty in identifying, quantifying, and tracking all variables over time, a trend variable is used to provide a comprehensive indicator of usage trends, which can then be used to forecast for a future period. Additionally, the trend variable is weighted by heating degree days to reflect a "weighted trend," which more accurately reflects that the impacts of these trends are directly related to usage during heating time periods.

For the Residential Heating groups of Rates R and RT, the multi-year period regression methodology is the same base method that the Company has utilized in prior rate cases, updated for the use of a common data set period of October 2003 through September 2021. October 2003 is the earliest common data set available for the entire service territory, given the timing and data availability of historic service and former rate district level details for UGI Gas and its former subsidiaries, UGI PNG and UGI CPG.

For the Company's core Commercial Heating rate groups (inclusive of Rates N, NT, and DS), the Company utilized the same regression method as presented in UGI Gas's 2019 and 2020 Gas Rate Cases. Specifically, to forecast the Commercial Heating rate group use per customer, the Company utilized three variables: (1) use per customer; (2) heating degree days; and (3) lagged heating degree days. For the Commercial Heating group, the Company used the period of October 2012 through September 2021 for regression modeling, or the period during which common non-residential rate structures existed for UGI Gas and its former subsidiaries.

The forecasts for end-of-FPFTY use per customer are generated using the regression results along with a projection of regression variable inputs including normal annual heating degree days and, where applicable, a weighted trend variable. The results are presented in summary on UGI Gas Exhibit SAE-4(a) and in detail on UGI Gas Exhibit SAE-4(c). In total, the result is a net sales decrease, from the fiscal 2023 budget, of 1,348 MMcf, and a net revenue decrease, from the fiscal 2023 budget, of $15.863 million, inclusive of PGC revenues.

Q. Why did UGI Gas utilize a multi-year regression period?

A. The Company decided to use the multi-year period because it provides a larger sample set of data to smooth out short-term variations and capture the underlying long-term use per customer trends to more accurately project usage per customer during the period rates are likely to be in effect. This methodology is consistent with that utilized in the last seven base rate cases of UGI Gas and its predecessor entities.

Q. Has UGI Gas compared the results of the multi-year regression method to develop normalized usage for Residential Heating and Commercial Heating customer groups with any other normalization method?

A. Yes. Please see UGI Gas Exhibits SAE-3(a) and SAE-3(b), which contain use per customer graphs that illustrate both the results of the multi-year normalized regression method I have explained above ("Normalized Multi-year") and a short-term normalized ("Normalized 12 Months ended") value for the same groups of Residential Heating and Commercial Heating customers. The short-term normalized values are computed via a simple determination of temperature sensitive load each month. As can be seen from these graphs, short-term trend fluctuations of the "Normalized 12 months ended" line occur in certain periods, but consistently revert to the long-term "Normalized Multi-year" trend which has been used to forecast FPFTY use per customer values, demonstrating the ongoing base trend in declining use per customer.

Q. Please explain the "Adjustment for PGC" shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for PGC" shown in summary on UGI Gas Exhibit SAE-4(a) annualizes FPFTY PGC revenues using the PGC rate in effect as of December 1, 2021. UGI Gas Exhibit SAE-4(d) provides the calculations for these adjustments. This adjustment increases PGC revenues for the FPFTY by $49.4 million.

Q. Please explain the following three adjustments shown in summary on UGI Gas Exhibit SAE-4(a): "Adjustment for MFC," "Adjustment for USP," and "Adjustment for GPC."

A. The Adjustment for MFC annualizes the Company's Merchant Function Charge ("MFC") revenues for the FPFTY based on the MFC surcharge rates in effect as of December 1, 2021. The MFC Adjustment increases projected revenues by $0.814 million.

The Adjustment for USP annualizes the Company's Universal Service Program ("USP") surcharge revenues for the FPFTY based on the USP Rider rate in effect as of December 1, 2021. The Adjustment for USP also updates the sales volume for Customer Assistance Program ("CAP") customers in the USP Revenue calculation with end of Fiscal Year 2021 data in comparison to the budgeted sales volume for CAP customers, which was calculated using end of Fiscal Year 2020 data. The USP adjustment increases revenues by $1.119 million.

The Adjustment for GPC annualizes the Gas Procurement Cost ("GPC") revenues to reflect the impact of all volume adjustments to the original Fiscal Year 2023 planned budget. The GPC adjustment decreases revenues by $0.111 million. Additional details for these three adjustments are provided on UGI Gas Exhibit SAE-4(e), UGI Gas Exhibit SAE-4(f), and UGI Gas Exhibit SAE-4(g), respectively.

Q. Please explain "Adjustment for Excess Take Revenues" as shown on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for Excess Take" detailed in UGI Gas Exhibit SAE-4(h) reflects the assumption that large transportation customers will evaluate new service elections and will make the necessary adjustments to avoid Excess Take penalties in the FPFTY. The Excess Take adjustment reduces revenue by $1.7 million.

Q. Please explain the "Adjustment for EEC Rider" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Rider" annualizes the revenue from the Energy Efficiency and Conservation ("EE&C") Rider ("EEC Rider") for the FPFTY based on the EEC Rider rate in effect as of December 1, 2021. This adjustment increases revenues by $3.809 million and is shown on UGI Exhibit SAE-4(i).

Q. Please explain the "Adjustment for EEC Conservation Impact" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for EEC Conservation Impact" annualizes the impact to revenues from

UGI Gas's ongoing EE&C programs and associated reduced energy consumption as a result of measures implemented as part of the EE&C programs. This adjustment decreases FPFTY sales by 239 MMcf and decreases revenues by $2.405 million and can be seen on UGI Gas Exhibit SAE-4(j).

Q. Please explain the "Adjustment for GET Gas" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for GET Gas" annualizes GET Gas residential revenues to reflect end of year conditions. The revised residential revenues were developed by annualizing the projected GET Gas surcharge payments at the end of the FPFTY. The adjustment also adds anticipated GET Gas revenues related to commercial customers, which were inadvertently omitted from the original FPFTY budget. In total this adjustment decreases revenues by $0.016 million, as shown on UGI Gas Exhibit SAE-4(k).

Q. Please explain the "Adjustment for GDE" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for GDE" annualizes Gas Delivery Enhancement ("GDE") Rider revenue based on the current rate as of December 1, 2021. This adjustment increases revenues by $0.020 million and is shown on UGI Gas Exhibit SAE-4(l).

Q. Please explain the "Adjustment for DSIC" on UGI Gas Exhibit SAE-4(a).

A. The "Adjustment for DSIC" annualizes Distribution System Improvement Charge ("DSIC") revenue based on the application of the 5% DSIC charge cap to FPFTY revenues. The FPFTY budget incorrectly excluded the projected DSIC rate revenues. This adjustment continues applying the 5% DSIC rate, projected at the end of the FTY, to the end of the FPFTY period. This allows the Company to properly quantify DSIC revenues, which will be rolled into the new base rates established in this proceeding as a result of re-setting the DSIC rate to zero. This adjustment increases revenues by $30.327 million and is shown on UGI Gas Exhibit SAE-4(m).

Q. Do the adjusted FPFTY revenues exclude revenues related to off-system sales and non-jurisdictional revenue?

A. Yes.

III. DEVELOPMENT OF SALES AND REVENUE FOR THE FTY AND HTY

Q. How were normalized and annualized sales and revenue determined for the FTY?

A. Budgeted sales and revenues serve as the starting point for the development of the normalized and annualized FTY sales and revenues, as shown in UGI Gas Exhibit SAE-5. All of the adjustments that were made in the development of the FPFTY sales and revenues were also made in the development of the FTY sales and revenues, with the exception of the adjustments for the EEC Conservation Impact and DSIC that are contained in the FPFTY, but not the FTY.

Q. How were normalized and annualized sales and revenue determined for the HTY?

A. Historic sales and revenues serve as the starting point for the development of the normalized and annualized HTY sales and revenues shown in UGI Gas Exhibit SAE-6. All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY, with the exception of the adjustments for the EEC Conservation Impact, GDE Rider, and DSIC.

IV. REVENUE ALLOCATION AND RATE DESIGN

Q. What is UGI Gas's ratemaking philosophy for revenue allocation and rate design?

A. The Company's ratemaking goal is to implement reasonable rates that recover its cost of doing business. Revenue allocation and rate design are generally developed to reflect reasonable movement toward class cost of service and to be competitive with prices of alternate energy sources, including bypass options. UGI Gas's rates and rate design seek to promote and achieve efficient utilization of the Company's facilities and natural gas supplies.

Q. What factors has the Company considered in establishing its proposed rate structure?

A. The Company considered class cost of service, rate of return and relative rate of return compared to the system average rate of return as the primary factors in determining revenue allocation and rate design. In measuring cost of service, the Company relied on the cost of service study prepared by Company witness Constance E. Heppenstall (UGI Gas Statement No. 10).

Q. What is the Company's proposed revenue allocation in this case?

A. Below is a summary of the proposed allocation of the $82.7 million increase proposed in this case, shown by rate class:

Rates R/RT	$68.1 million
Rates N/NT	$14.4 million
Rate DS	$0.7 million
Rate LFD	$1.5 million
Rate XD	($1.0 million)
Rate IS	($1.0 million)

Q. What were the Company's goals in deriving its proposed revenue allocation?

A. The Company's goals for revenue allocation were two-fold. First, the Company wanted to materially move all classes towards the system average rate of return. Second, the Company wanted to complete the unification of the DS and N/NT rate classes for the former North and South/Central Rate Districts.

UGI Gas's proposed revenue allocation accomplishes both of these two goals. The revenue allocation moves all customer classes toward system average rate of return, while also completing the unification of the Rate DS and N/NT classes.

Q. How does the Company's proposed revenue allocation move all customer classes toward system average rate of return?

A. Table 1 below shows the percentage increase in distribution revenue, excluding gas costs, and summarizes the changes in relative rates of return by rate class. The percentage movement towards the system average rate of return is also included in the table data.

Table 1. – Percent Increase, Relative Rate of Return ("ROR") and Change in Relative ROR

Rate	Percent increase (without gas costs)	Relative ROR-present rates	Relative ROR-proposed rates	Change in relative ROR	Percent movement in relative ROR toward unity ROR
R/RT	18.1%	0.70	0.87	0.17	56%
N/NT	10.4%	1.18	1.08	0.10	-56%
DS	1.9%	1.40	1.10	0.30	-75%
LFD	3.4%	1.54	1.24	0.30	-56%
XD	-2.6%	2.28	1.64	0.64	-50%
IS	-4.4%	2.19	1.54	0.65	-55%
Total	12.4%	1.0	1.0	1.0	

Q. Could you please explain how you developed the proposed revenue allocation and achieved rate uniformity for both the Rates N/NT and Rate DS customer classes?

A. For Rate R/RT, Rate N/NT, and Rate LFD, UGI Gas allocated a portion of the total proposed increase to those classes by determining an amount that moves each class by an equivalent percentage towards the system average rate of return. Moving an equivalent percentage toward the system average rate of return achieves a just and reasonable revenue allocation. As part of this process, the Company also unified the former North Rate District's Rate N/NT class rates with the former South and Central Rate Districts' Rate N/NT class rates as a rate design element.

In addition, the Company looked at unifying the Rate DS classes in the former North Rate District with those from the former South and Central Rate Districts. Since the Company first began moving its customers to uniform rates in 2019, the resulting impact to the Rate DS class in the former North Rate District has served as a limiting factor for consideration for the overall revenue allocation. Completing unification in this case is reasonable in terms of the level of impact to these customers. As the total system average increase in distribution rates (non-gas costs rates) proposed in this case is 12.4%, the increase to this Rate DS group was limited to two times (2x) the system average increase, or 24.8%. Limiting the increase by a maximum of two times the overall increase in distribution rates is consistent with the methodology utilized in the Company's proposals in past rate cases in order to limit the overall impact to any one particular customer group affected by the overall rate increase.

Furthermore, the distribution rates for the former South and Central Rate DS class were adjusted in order to achieve uniformity across the entire Rate DS class. This resulted in an overall decrease to the former South and Central Rate DS class of 4.1% and an overall

Rate DS class increase of 1.9% (in terms of non-gas cost rates). These collective changes to Rate DS resulted in a total revenue allocation of $653,946 of the total requested $82.7 million increase.[1]

Additionally, UGI Gas recognized that its competitive negotiated rate classes of Rate XD and Rate IS (Interruptible) have relative rates of return at present rates that are all well above system average (more than 2x system average). As such, the Company is proposing no incremental revenue allocation to these rate classes. These classes are subject to competitive limitations on an ongoing basis, and rates charged are routinely reviewed and established on a competitive alternative basis to assure overall benefits to all customers are maximized.

Q. Please describe the impacts related to revenue allocation and rate design for the residential Rate R customer group.

A. As evidenced by the cost of service study presented by Ms. Heppenstall, under present rates, the residential Rate R customer group (Rates R and RT) is producing a return of 4.33%, as compared to a system average return of 6.14%. This translates to a relative rate of return of 0.70 compared to the system average. In allocating revenues, the Company proposes to allocate $68.1 million of the revenue increase to the Rate R customer group in order to move it closer toward cost of service. This increase will result in an overall return

[1] Moreover, it should be noted that the Company has considered gradualism in the context of the increase to the former North Rate District Rate DS class. Despite the Company's proposal to unify Rate DS rates for all customers in the 2019 and 2020 Gas Rate Cases, only modest movement has been achieved in settlement. Thus, former North Rate District Rate DS customers have now continued to pay below system average Rate DS rates for a period of three years. These lower rates have accrued benefits over the three-year period to the former North Rate District Rate DS customers and further support the movement to the full proposed rates in this proceeding, which, as explained above, were limited to an increase equal to two times the system average. Based on these reasonableness checks for gradualism, the Company believes uniform rates for Rate DS are an appropriate outcome of this proceeding.

of 6.94% for the Rate R customer group, compared to the proposed system average of 7.97%, and a relative rate of return of 0.87; thus, moving the Rate R customer group more than halfway toward system average rate of return.

As to rate design, the Company is proposing a Rate R customer charge of $19.95 per month, as compared to the current charge of $14.60 per month, to better reflect the direct customer costs per bill of $27.47, as identified within the cost of service study presented in UGI Gas Exhibit D. This partial movement toward the direct customer cost per bill reflects the Company's application of the ratemaking principle of gradualism.

Q. Please describe the impacts related to revenue allocation and rate design for the small commercial Rate N customer group.

A. For the small commercial Rate N customer group (Rates N and NT), current rates are producing a return of 7.28% with a relative rate of return 1.18. UGI Gas proposes to allocate $14.4 million of the revenue increase to the Rate N customer group. This increase will result in an overall return of 8.62% or a relative rate of return of 1.08; thus, moving the Rate N customer group more than halfway toward system average rate of return.

As to rate design, the Company is proposing a Rate N customer group customer charge of $30.00 per month, as compared to the current charge of $23.50 per month, to better reflect the direct customer costs per bill of $45.87 as identified within the cost of service study presented in UGI Gas Exhibit D. This partial movement toward the direct customer cost per bill reflects the Company's application of the ratemaking principle of gradualism.

Q. Please describe the impact of the revenue allocation and rate design for Rate DS.

A. For Rate DS, current rates are producing a return of 8.61%, with a relative rate of return of

1.40. The Company proposes to allocate $653,946 of the revenue increase to the Rate DS customers in order to increase their rates in the former North Rate District and decrease rates for the former South and Central Rate District customers to achieve unity in this customer group. These adjustments in rates will result in an overall class return of 8.79% or a relative rate of return of 1.10.

As to rate design, the Company is proposing to maintain the current Rate DS customer charge of $260.00 per month. The $260.00 per month charge is fully supported by the direct customer costs per bill for Rate DS of $370.12 as identified within the cost of service study presented in UGI Gas Exhibit D.

Q. Is the Company proposing any change to the rate assessed under Rate NNS (No Notice Service)?

A. Yes. Rate NNS is a daily balancing service offered by the Company. It provides an alternate election of a daily balancing tolerance for transportation customers, allowing a customer to optionally elect a balancing tolerance greater than the standard basic balancing provided by the Company. A customer is able to make an election under Rate NNS up to its DFR (Daily Firm Requirement) contract demand level and pay only for the level chosen. The Company is proposing to update the tariffed NNS rate to reflect current cost elements, using the methodology from the Company's 2019 Gas Rate Case.

Q. How was the proposed NNS rate developed?

A. The charge for providing service under Rate NNS is a monthly charge established using the Company's cost of interstate storage that can be utilized for balancing excess or shortfall requirements on the Company system. UGI Gas Exhibit SAE-8 shows the calculation of the Rate NNS charge. This charge was developed based on the same methodology used in the Company's 2019 Gas Rate Case. As seen on UGI Gas Exhibit SAE-8, the proposed NNS rate is $0.1860 per Mcf/d of an elected daily no notice allowance ("NNA") tolerance quantity. This compares to a current NNS rate of $0.4880 per Mcf/d of elected NNA, which was established in the Company's 2020 Gas Rate Case (See Ordering Paragraph 22 in the Commission's Order issued on October 8, 2020 at Docket Nos. R-2019-3015162, *et al.*).

Q. Will the Company continue to credit the revenues received from Rate NNS to PGC Rates?

A. Yes, revenues from Rate NNS will continue to be credited to the PGC Rates as part of the Company's annual 1307(f) proceeding.

Q. Please describe Rate MBS (Monthly Balancing Service).

A. Rate MBS is a monthly balancing service offered by the Company. Service under Rate MBS allows transportation imbalances of up to 10% for the month to be carried forward in the customer's MBS account for delivery of excess volumes, or receipt of shortfalls, in subsequent months.

Q. Has the Company proposed any changes to the Rate MBS rates?

A. Yes. UGI Gas Exhibit SAE-9 provides the basis for the MBS rate calculation. As a result of the settlement in the Company's 2019 Gas Rate Case, storage demand charges were included in the calculation of Rate MBS on a 100% load factor basis and the Company is continuing that inclusion in the proposed rates presented. The MBS rate is updated annually on December 1st each year, using 12 months of data ending in September, for the average monthly imbalance utilized in development of the rate. The MBS rates most recently updated for December 1, 2021, are: \$0.0277/Mcf for Rates DS and IS; \$0.0160/Mcf for Rate LFD; and \$0.0165/Mcf for Rate XD. As seen on UGI Gas Exhibit SAE-9, the proposed, MBS rates will be: \$0.0437/Mcf for Rates DS and IS; \$0.0263/Mcf for Rate LFD; and \$0.0221/Mcf for Rate XD; in particular, these Rate MBS increases are principally driven by recent increases to the Company's applicable storage demand charges.

Q. Will the Company continue to credit the revenues received from Rate MBS to PGC Rates?

A. Yes, revenues from Rate MBS will continue to be credited to the PGC as part of the Company's annual 1307(f) proceeding.

Q. Please describe the GPC.

A. The GPC recovers costs associated with gas procurement that were unbundled from base rates.

Q. Is the Company proposing to update its GPC in this proceeding?

A. No. The Company proposes to continue the \$0.0660/Mcf blended rate that was approved in the Company's 2020 Gas Rate Case (see Joint Petition for Approval of Unopposed Settlement of All Issues, Appx. A, p. 12, filed on August 3, 2020, at Docket Nos. R-2019-3015162, *et al.*, which was approved by the Commission's Opinion and Order entered on October 8, 2020, in that proceeding).

Q. Please describe the MFC.

A. The MFC is equal to the fixed percentage of purchased gas costs that are expected to be uncollectible.

Q. Is the Company proposing to update its MFC in this proceeding?

A. Yes. The Company is updating the percentages for the MFC rates to reflect the actual uncollectible expense for the last three years. Based on this updated data, the residential MFC will be 2.27%, and the MFC for the commercial class will be 0.44%. Please see UGI Gas Exhibit SAE-10 for additional details.

Q. Please describe the USP Rider.

A. The USP Rider recovers those costs associated with the provision of universal service offerings approved by the Commission in the Company's Universal Service and Energy Conservation Plan.

Q. Is the Company proposing any changes to the USP Rider?

A. Yes. The Company is proposing changes to the annual reconciliation provisions of Rider F – Universal Service Program "USP" to update the threshold number of customers enrolled in the Customer Assistance Program ("CAP") that is used in the calculation of the offset applied to recoverable CAP costs. This offset reduces the Company's recovery of CAP spending above projected enrollment to account for write-offs of bad debt that would arguably have occurred if not for CAP. The Company proposes to set the CAP enrollee threshold equal to the number of CAP participants as of September 30, 2022, to provide an enrollee figure that reflect the actual ongoing impacts on CAP enrollment. This proposal is consistent with the establishment of the CAP enrollee figure in the last UGI Gas 2020 Rate Case at Docket No. R-2019-3015162.

V. TARIFF CHANGES

Q. What tariff changes are being proposed in this case?

A. The Company is revising references to the Supplement number, Notice language, Issue and Effective dates, and page numbers as necessary per this case. Apart from the proposed rate schedule changes, a complete list of tariff modifications can be found in the List of Changes Made by the Supplement section in UGI Gas Exhibit F – Proposed Supplement No. 32 to UGI Gas Tariff No. 7 and Proposed Supplement No. 32 to UGI Gas Tariff No. 7S. As previously stated, the Company is proposing to complete the unification of the DS and N/NT rate classes for the former North and South/Central Rate Districts. To that end, UGI Gas is proposing to fully consolidate the listings of counties served in the Description of Territories Served, which are currently apportioned by the three former Rate Districts. More significant proposed changes to the tariffs include:

- Rider C - The current Extended Tax Cuts and Job Act ("TCJA") Temporary Surcharge Rider C has been removed as the surcharge has ended. In replacement, the Company proposes to add a new Rider C, Weather Normalization Adjustment ("WNA") Rider C, which is detailed in the direct testimony of John D. Taylor (UGI Gas Statement No. 11).
- References to the expired Rider C, TCJA Temporary Surcharge have been deleted from the following rate schedules: Rate R, RT, GL, N, NT, DS, LFD, XD, R/S, and IS.

- The State Tax Adjustment Surcharge, Rider A, has been rolled into rates and reset to 0.00%.
- The reference to Rate Gas Beyond the Main ("GBM") in Rider A has been removed, as that rate has now been eliminated.
- Rider D - MFC has been set to 2.27% for PGC Residential Customers and 0.44% for Non-Residential PGC Customers, as described above.
- Section 15. Price to Compare ("PTC") has been updated to reflect changes to the MFC.
- Rider F – Universal Service Program has been revised so that the CAP credit bad debt offset will be associated with the participants in excess of the number of CAP enrollees as of September 30, 2022, in place of the existing September 30, 2020 date.
- Rider I – DSIC has been reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b).
- Rate NNS – The existing NNS election volumetric option, specific to the former rate districts for customers not having daily metering, have been removed, as the Company now has daily metering on all applicable customers.
- Rate NNS and MBS have been revised to remove outdated language that was applicable for service prior to November 1, 2020.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

Work Experience

UGI Utilities, Inc., Denver, PA

November 2019 – Present	Senior Manager, Tariff & Supplier Administration
2018 – November 2019	Manager, Revenue/Sales & Choice Administration

UGI Utilities, Inc., Reading, PA

2000 – 2018	Rates Analyst – I/II/Sr/Principal (Progressive Positions)
1997 – 2000	Data and Expense Analyst – Residential Marketing
1990 – 1997	Staff Accountant – Supply Accounting
1989 – 1990	Accounting Assistant, Supply – Accounting
1988 – 1989	Accounting Assistant, Rates & Budgets – Accounting
1986 - 1988	Accounting Assistant B – Accounting

Education

Bachelor of Science, Accounting, Albright College, 1995

Associate of Science, Business Administration, Pennsylvania State University, 1986

Previous testimony provided before the Pennsylvania Public Utility Commission:

Docket No. R-2021-3023618 UGI Electric Base Rate Case

UGI GAS

EXHIBIT SAE-2

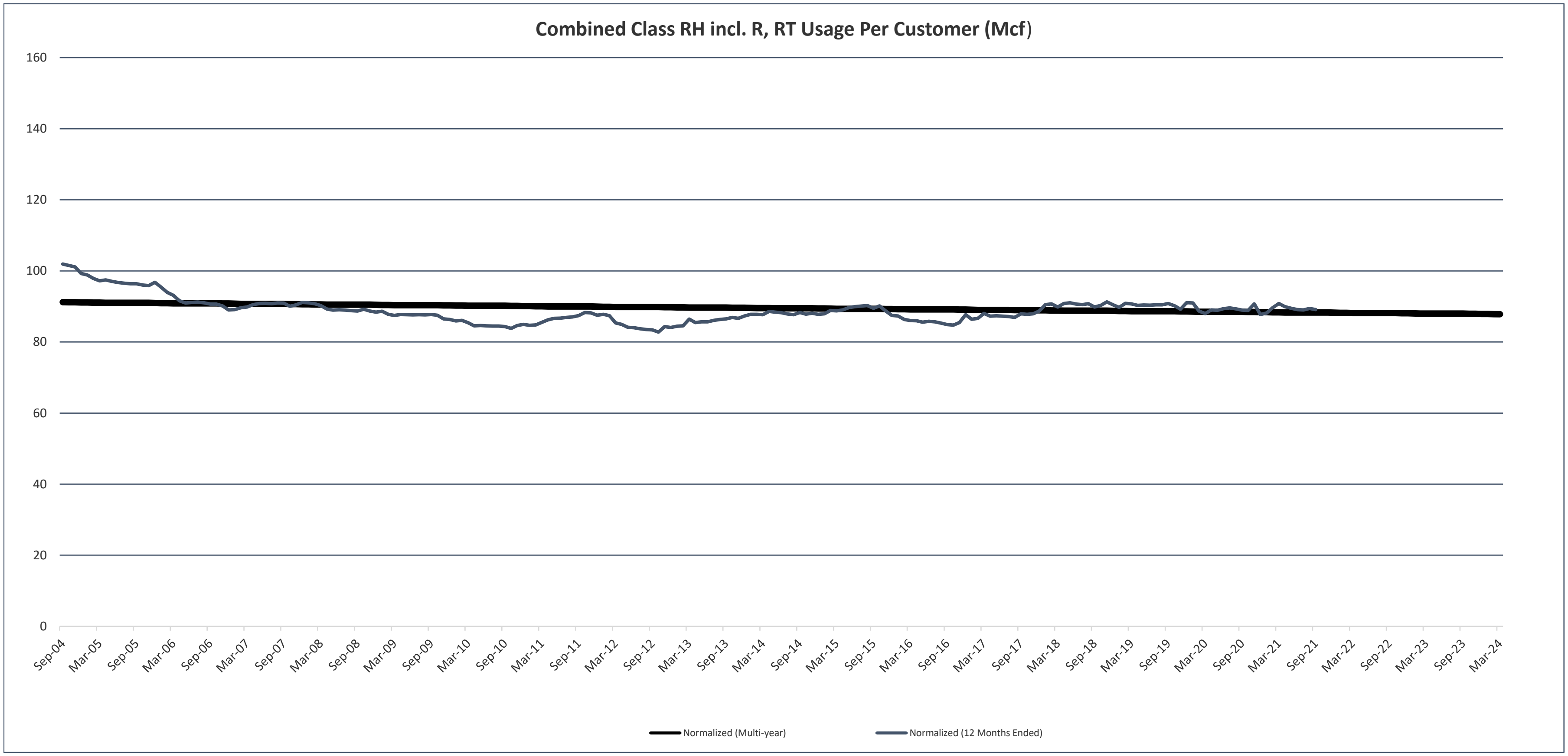
UGI Utilities, Inc. - Gas Divison
15 Year Normal Heating Degree Days (2005-2019)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	15 Year Average *
Jan	1,195	891	996	1,053	1,292	1,154	1,251	999	1,042	1,313	1,236	1,132	956	1,150	1,140	1,120
Feb	943	953	1,178	977	931	1,018	947	813	975	1,114	1,282	915	714	769	900	962
Mar	950	774	816	823	777	627	834	484	882	974	961	578	865	904	826	805
Apr	391	391	550	373	425	327	414	431	424	464	409	464	261	567	318	414
May	282	198	144	279	180	154	126	70	175	153	88	221	206	62	119	164
Jun	21	46	27	26	43	25	20	37	21	15	36	24	32	30	27	30
Jul	4	4	20	7	20	5	1	1	5	14	6	3	3	3	1	0
Aug	5	11	24	23	19	9	11	8	15	16	11	2	20	2	7	16
Sep	47	129	79	85	116	68	75	110	140	100	47	53	90	58	34	83
Oct	357	431	227	467	436	383	399	336	330	305	385	319	230	365	272	350
Nov	613	555	741	724	569	670	559	782	774	764	516	586	687	771	769	672
Dec	1,121	814	1,008	1,016	1,052	1,162	841	844	1,009	916	631	974	1,086	883	926	952
Totals	5,929	5,197	5,810	5,853	5,860	5,602	5,478	4,915	5,792	6,148	5,608	5,271	5,150	5,564	5,339	5,568

*Average adjusted for rounding of 15 year calculation and normal representation of Heating Degree Days falling consecutively through normal year.

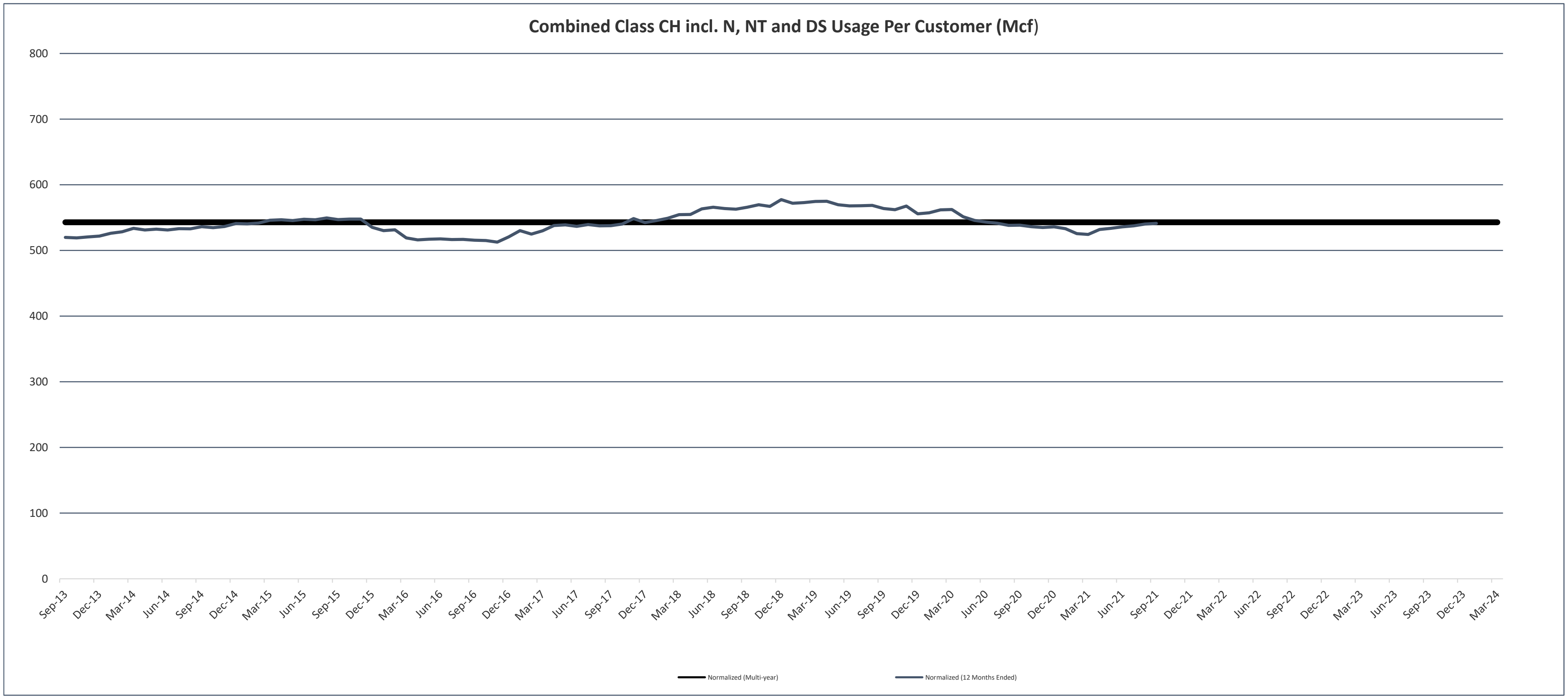
UGI GAS

EXHIBIT SAE-3(a)


Combined Class RH incl. R, RT Usage Per Customer (Mcf)
160
140
120
100
80
60
40
20
0
Sep-04
Mar-05
Sep-05
Mar-06
Sep-06
Mar-07
Sep-07
Mar-08
Sep-08
Mar-09
Sep-09
Mar-10
Sep-10
Mar-11
Sep-11
Mar-12
Sep-12
Mar-13
Sep-13
Mar-14
Sep-14
Mar-15
Sep-15
Mar-16
Sep-16
Mar-17
Sep-17
Mar-18
Sep-18
Mar-19
Sep-19
Mar-20
Sep-20
Mar-21
Sep-21
Mar-22
Sep-22
Mar-23
Sep-23
Mar-24
Normalized (Multi-year)
Normalized (12 Months Ended)

UGI GAS

EXHIBIT SAE-3(b)


Combined Class CH incl. N, NT and DS Usage Per Customer (Mcf)
800
700
600
500
400
300
200
100
0
Sep-13
Dec-13
Mar-14
Jun-14
Sep-14
Dec-14
Mar-15
Jun-15
Sep-15
Dec-15
Mar-16
Jun-16
Sep-16
Dec-16
Mar-17
Jun-17
Sep-17
Dec-17
Mar-18
Jun-18
Sep-18
Dec-18
Mar-19
Jun-19
Sep-19
Dec-19
Mar-20
Jun-20
Sep-20
Dec-20
Mar-21
Jun-21
Sep-21
Dec-21
Mar-22
Jun-22
Sep-22
Dec-22
Mar-23
Jun-23
Sep-23
Dec-23
Mar-24
Normalized (Multi-year)
Normalized (12 Months Ended)

UGI GAS

EXHIBIT SAE-4(a) – (m)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year 2023 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2023	342,178	986,747	602,316	
Adjustment for Customer/Contract Changes	(194)	278	158	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	(1,348)	(15,863)	(5,673)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-4(c)
Adjustment for PGC		49,419	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(d)
Adjustment for MFC		814	814	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(e)
Adjustment for USP		1,119	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(f)
Adjustment for GPC		(111)	(111)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(h)
Adjustment for EEC Rider		3,809	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(i)
Adjustment for EEC Conservation Impact	(239)	(2,405)	(1,032)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(j)
Adjustment for Get Gas		(16)	(16)	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(k)
Adjustment for GDE		20	0	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(l)
Adjustment for DISC		30,327	30,327	UGI Utilites, Inc.- Gas Division-Exhibit SAE-4(m)
Fully Projected Future Test Year 2023	340,397	1,052,437	625,083	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	FPFTY Revenues (Unadjusted)	$ 7,774	$ 569,371	$ 44,272	$ 7,709	$ 162,770	$ 7,711	$ 52,182	$ 32,197	$ 102,761	$ 986,747
2	FPFTY PGC Revenues	$ (2,181)	$ (279,118)	$ (3,110)	$ (4,081)	$ (90,242)	$ (4,518)	$ 32	(642)	(571)	(384,431)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 5,593	$ 290,254	$ 41,162	$ 3,628	$ 72,528	$ 3,193	$ 52,213	$ 31,555	$ 102,191	$ 602,316
4	FPFTY Average Effective Customers (Unadjusted)	23,011	512,710	80,279	3,289	47,586	660	18,617	1,392	1,021	688,565
5	FPFTY Average Annual Margin Per Customer (L3 / L4 or Weighted Value by District)	$ 0.243	$ 0.566	$ 0.513	$ 0.974	$ 0.851	$ 4.890	$ 2.805	$ 22.669	$ 100.089	$ 0.875
6	FPFTY Customers (Fully Adjusted)	22,732	513,121	80,279	3,295	47,558	655	18,617	1,392	1,021	688,670
7	Change in Customers during FPFTY (L6 - L4)	(279)	411	-	6	(28)	(5)	-	-	-	105
8	Annualization of Margin (L5 * L7)	$ (68)	$ 233	$ -	$ 6	$ (24)	$ (22)	$ -	$ -	$ 34	$ 158
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4 or Weighted Value by District)	$ 0.338	$ 1.111	$ 0.551	$ 2.212	$ 2.757	$ 11.742	$ 2.803	$ 23.130	$ 100.648	$ 1.433
10	Annualization of Total FPFTY Revenue (L7 * L9)	$ (94)	$ 456	$ -	$ 13	$ (78)	$ (53)	$ -	$ -	$ 34	$ 278
11	Annualization Adjustment for FPFTY PGC Revenues (L10 - L8)	$ (26)	$ 224	$ -	$ 7	$ (54)	$ (31)	$ -	$ -	$ -	$ 119
12	Total FPFTY UPC (Unadjusted) - MCF	15.80	90.90	82.10	225.10	343.90	1,242.50	708.00	6,905.50		
13	Annualization Adjustment for FPFTY Sales - MMCF (L7 * L12)/1000	(4)	37	-	1	(10)	(6)	-	-	(213)	(194)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-4(b)(1)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FPFTY Revenues (Unadjusted)	$ 44,333	$ 35,427	$ 1,887	$ 21,115	$ 102,761
2	FPFTY PGC Revenues	(571)	-	-	-	(571)
3	FPFTY Revenues net of PGC - Margin (Unadjusted)	$ 43,762	$ 35,427	$ 1,887	$ 21,115	$ 102,191
4	FPFTY Average Effective Customers (Unadjusted)	602	56	57	306	1,021
5	FPFTY Average Annual Margin Per Customer (L3 / L4)	$ 72.694	$ 632.627	$ 33.107	$ 69.002	$ 100.089
6	FPFTY Customers (Fully Adjusted)	604	56	57	304	1,021
7	Change in Customers during FPFTY (L6 - L4)	2	-	-	(2)	(0)
8	Annualization of Margin	$ (236)	$ 309	$ -	$ (39)	$ 34
9	Average Annual Revenue Per Customer (L1 / L4)	$ 73.642	$ 632.627	$ 33.107	$ 69.002	$ 100.648
10	Annualization of Total FPFTY Revenue	$ (236)	$ 309	$ -	$ (39)	$ 34
11	Annualization of FPFTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FPFTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FPFTY Sales - MMCF	(136)	-	-	(77)	(213)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Reconciliation Adj. *	[11] Total
1	FPFTY (Unadjusted) Use/Customer ("UPC") - MCF	15.80	90.90	82.10	225.10	343.90	1,242.50	708.00	6,905.50			
2	FPFTY UPC (Fully Adjusted) - MCF	16.30	88.00	82.90	215.10	346.00	1,109.50	712.50	6,905.50			
3	Change in UPC - MCF (L2 - L1)	0.50	(2.90)	0.80	(10.00)	2.10	(133.00)	4.50	0.00			
4	FPFTY Customers (Fully Adjusted)	22,732	513,121	80,279	3,295	47,558	655	18,617	1,392	1,021	-	688,670
5	Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	11	(1,488)	64	(33)	100	(87)	85	-	-	-	(1,348)
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 129	$ (16,856)	$ 315	$ (331)	$ 1,001	$ (878)	$ 281	$ -	$ -	$ 477	$ (15,863)
7	Total Unit Revenue Adjustment (L6 / L5)	$ 11.3277	$ 11.3277	$ 4.9080	$ 10.0595	$ 10.0246	$ 10.0836	$ 3.3271	$ -	$ -		
8	Distribution Margin Adjustment (L5 * L9)	$ 47	$ (6,116)	$ 264	$ (117)	$ 353	$ (312)	$ 266	$ -	$ -		$ (5,617)
9	Distribution Unit Rate (Rate N/NT Weighted Value by District)	$ 4.1104	$ 4.1104	$ 4.1104	$ 3.5647	$ 3.5314	$ 3.5877	$ 3.1483	$ -	$ -		
10	PGC Revenue (L5 * L11)	$ 71	$ (9,340)	$ -	$ (207)	$ 627	$ (547)	$ -	$ -	$ -	$ 1	$ (9,395)
11	PGC Unit Rate	$ 6.2767	$ 6.2767		$ 6.2767	$ 6.2767	$ 6.2767					
12	EE&C Revenue Adjustment (L5 * L13)	$ 2	$ (309)	$ 13	$ (1)	$ 2	$ (2)	$ 2	$ -	$ -		$ (292)
13	EE&C Unit Rate	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0556	$ -		
14	USP Revenue Adjustment (L5 * L15)	$ 4	$ (530)	$ 23	$ -	$ -	$ -	$ -	$ -	$ -		$ (503)
15	USP Unit Rate	$ 0.3562	$ 0.3562	$ 0.3562	$ -	$ -	$ -	$ -	$ -	$ -		
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ 2	$ (203)		$ (1)	$ 2	$ (2)	$ -	$ -	$ -		$ (201)
17	MFC Unit Rate	$ 0.1362	$ 0.1362		$ 0.0176	$ 0.0176	$ 0.0176	$ -	$ -	$ -		
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 3	$ (358)	$ 15	$ (6)	$ 18	$ (16)	$ 13	$ -	$ -		$ (331)
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	0.0500			
20	Total Margin Adjustment (L8 + L16 + L18)	$ 51	$ (6,677)	$ 279	$ (124)	$ 372	$ (330)	$ 279	$ -	$ -	$ 476	$ (5,673)
21	Total Unit Margin Adjustment (L20 / L5)	$ 4.4871	$ 4.4871	$ 4.3441	$ 3.7624	$ 3.7275	$ 3.7865	$ 3.3067	$ -	$ -		

Notes:

* Column (10) Adjustment reflective of interdependent relationship of sequential adjustment impacts.

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for PGC

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original Budget PGC Rate FPFTY	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	
FPFTY PGC Rate	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	
PGC Rate Variance	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	
Total PGC Volumes	3,699	7,394	10,289	13,124	10,566	8,699	4,479	2,017	1,161	939	1,007	1,537	64,912
PGC Revenue Adjustment	$2,816	$5,629	$7,834	$9,992	$8,044	$6,622	$3,410	$1,536	$884	$715	$767	$1,170	$49,419

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for MFC

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original Budget PGC Rate FPFTY	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	
FPFTY PGC Rate	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	
PGC Rate Variance	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	
Total PGC Volumes-Rate R	2,681	5,356	7,447	9,491	7,649	6,302	3,248	1,460	837	676	725	1,112	
Total PGC Volumes-Rate N	1,018	2,038	2,842	3,633	2,917	2,397	1,231	557	324	264	282	426	
Total PGC Volumes	3,699	7,394	10,289	13,124	10,566	8,699	4,479	2,017	1,161	939	1,007	1,537	64,912
Rate R %	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	
Rate N %	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	
MFC Rate R Adj Rate	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	$0.0165	
MFC Rate N Adj Rate	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	$0.0021	
Rate R Revenue Variance	$44	$88	$123	$157	$126	$104	$54	$24	$14	$11	$12	$18	
Rate N Revenue Variance	$2	$4	$6	$8	$6	$5	$3	$1	$1	$1	$1	$1	
Total Revenue Variance	$46	$93	$129	$165	$133	$109	$56	$25	$15	$12	$13	$19	$814

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for USP

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original FPFTY Budget USP Calculation	$983	$1,949	$2,691	$3,409	$2,761	$2,284	$1,188	$531	$298	$237	$256	$401	$16,989
Correct FPFTY Budget USP Calculation	$933	$1,849	$2,554	$3,235	$2,620	$2,167	$1,127	$504	$283	$225	$243	$380	$16,120
Variance to correct Original FPFTY Budget Calculation	($50)	($100)	($138)	($174)	($141)	($117)	($61)	($27)	($15)	($12)	($13)	($21)	($869)
Original FPFTY Budget USP Rate	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	
FPFTY USP Rate	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	
USP Rate Variance	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	
Total Rate R Volumes	3,100	6,146	8,487	10,752	8,707	7,203	3,746	1,675	940	748	807	1,265	53,576
Total Rate R excl CAP Volumes	2,941	5,832	8,053	10,202	8,262	6,834	3,554	1,589	892	710	766	1,200	50,835
USP Rate Revenue Variance	$115	$228	$315	$399	$323	$267	$139	$62	$35	$28	$30	$47	$1,988
Total Revenue Variance	$65	$128	$177	$224	$182	$150	$78	$35	$20	$16	$17	$26	$1,119

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for GPC

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
GPC Rate	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FPFTY Budget	(96)	(192)	(266)	(339)	(273)	(225)	(116)	(52)	(30)	(24)	(26)	(40)	(1,680)
Revenue Variance	($6)	($13)	($18)	($22)	($18)	($15)	($8)	($3)	($2)	($2)	($2)	($3)	($111)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)	(283)
$/MCF	$6.00
Excess Take Revenue/Margin	($1,700)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for EEC Rider

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original FPFTY Budget DS EEC Calculation	$40.6	$67.2	$102.6	$128.1	$118.8	$96.3	$56.7	$34.0	$24.5	$21.1	$21.7	$26.1	$737.7
Correct FPFTY Budget DS EEC Calculation	$40.4	$67.0	$102.2	$127.7	$118.4	$96.0	$56.5	$33.9	$24.5	$21.1	$21.7	$26.0	$735.3
Variance to correct Original FPFTY Budget Calculation	($0.2)	($0.3)	($0.4)	($0.5)	($0.4)	($0.3)	($0.2)	($0.1)	($0.0)	($0.0)	($0.0)	($0.0)	($2.4)
Original Budget FPFTY R/RT Rate	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	
FPFTY R/RT Rate	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	$0.2077	
R/RT Rate Variance	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	$0.0530	
R/RT Rate Volumes	3,100	6,146	8,487	10,752	8,707	7,203	3,746	1,675	940	748	807	1,265	53,576
R/RT Revenue Adjustment	$164	$326	$450	$570	$461	$382	$199	$89	$50	$40	$43	$67	$2,840
Original Budget FPFTY N/NT Rate	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
FPFTY N/NT Rate	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	$0.0204	
N/NT Rate Variance	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	$0.0228	
N/NT Rate Volumes	1,835	3,485	4,776	6,039	4,890	4,053	2,172	1,077	695	597	627	863	31,109
N/NT Revenue Adjustment	$42	$79	$109	$138	$111	$92	$50	$25	$16	$14	$14	$20	$709
Original Budget FPFTY DS Rate	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	
FPFTY DS Rate	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	$0.0556	
DS Rate Variance	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	($0.0053)	
DS Rate Volumes	512	856	1,330	1,697	1,550	1,272	738	442	321	277	281	336	9,612
DS Revenue Adjustment	($3)	($5)	($7)	($9)	($8)	($7)	($4)	($2)	($2)	($1)	($1)	($2)	($51)
Original Budget FPFTY LFD Rate	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	
FPFTY LFD Rate	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	$0.0316	
LFD Rate Variance	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	$0.0132	
LFD Rate Volumes	1,836	2,170	2,487	2,761	2,467	2,275	1,911	1,700	1,546	1,494	1,536	1,593	23,775
LFD Revenue Adjustment	$24	$29	$33	$36	$33	$30	$25	$22	$20	$20	$20	$21	$314
Total Revenue Adjustment	$227	$429	$584	$735	$597	$497	$269	$133	$84	$72	$76	$106	$3,809

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for EE&C Conservation Impact

EE&C Plan (Version 1/15/2019)

Yearly Gas Savings by Rate Class 2020 - 2035 (Cumulative MMBtus)

Rate Class Description	***Fiscal Year*** **2020**	**2021**	**2022**	**2023**	**2024**	**MMBTU 5 Year Average**	**BTU**	**MCF 5 Year Average**	**Customers FY23 Retail Htg & Choice Htg**	**EE&C UPC Conservation Adj**
Residential (R/RT)	145,463	157,325	171,179	175,233	176,395	165,119	1.034	159,690	497,635	**(0.3)**
Nonresidential (N/NT)	29,620	38,139	45,037	50,308	50,308	42,682	1.034	41,279	53,885	**(0.8)**
Total	**175,083**	**195,464**	**216,217**	**225,540**	**226,703**	**207,802**		**200,969**	**551,520**	

Line #	Description	[1] Rate R Residential-Htg	[2] Rate RT Residential Htg-RT	[3] Rate N Commercial-Htg	[4] Rate NT Commercial Htg-NT	[5] Rate N Industrial	[6] Rate NT Industrial -NT	[7] Total
1	FPFTY Use/Customer ("UPC") (Fully Adjusted) - MCF	88.0	86.2	346.0	689.5	1,109.5	2,242.6	
2	FPFTY UPC (Fully Adjusted-Incl EE&C Impact) - MCF	87.7	85.9	345.2	688.7	1,108.7	2,241.8	
3	Change in UPC -MCF	(0.3)	(0.3)	(0.8)	(0.8)	(0.8)	(0.8)	
4	End of Year FPFTY Customers	513,121	76,480	47,558	16,746	655	456	655,016
5	Annualization Adjustment for Sales - MMCF (L3 * L4) / 1000	(165)	(25)	(36)	(13)	(1)	(0)	(239)
6	Total Revenue Adjustment (L10 + L12 + L14 + L22)	$ (1,865)	$ (120)	$ (365)	$ (48)	$ (5)	$ (1)	$ (2,405)
7	Total Unit Revenue Adjustment (L6 / L5)	11.3277	4.9080	10.0246	3.7556	10.0833	3.8115	10.0515
8	Distribution Margin Adjustment (L5 * L9)	$ (677)	$ (101)	$ (129)	$ (46)	$ (2)	$ (1)	$ (955)
9	Distribution Unit Rate (Rates N, DS Weighted Value by District)	$ 4.1104	$ 4.1104	$ 3.5314	$ 3.5564	$ 3.5873	$ 3.6096	
10	PGC Revenue (L5 * L11)	$ (1,034)	$ -	$ (229)	$ -	$ (3)	$ -	$ (1,265)
11	PGC Unit Rate	$ 6.2767		$ 6.2767		$ 6.2767		
12	EE&C Revenue Adjustment (L5 * L13)	$ (34)	$ (5)	$ (1)	$ (0)	$ (0)	$ (0)	$ (40)
13	EE&C Unit Rate	$ 0.2077	$ 0.2077	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	
14	USP Revenue Adjustment (L5 * L15)	$ (59)	$ (9)					$ (67)
15	USP Unit Rate	$ 0.3562	$ 0.3562					
16	MFC Revenue/Margin Adjustment (L5 * L17)	$ (22)		$ (1)		$ (0)		$ (23)
17	MFC Unit Rate	$ 0.1362		$ 0.0176		$ 0.0176		
18	DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ (40)	$ (6)	$ (7)	$ (2)	$ (0)	$ (0)	$ (54)
19	DSIC Unit Rate	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	$ 0.0500	
20	Total Margin Adjustment (L8 + L16 + L18)	$ (739)	$ (107)	$ (136)	$ (48)	$ (2)	$ (1)	$ (1,032)
21	Total Unit Margin Adjustment (L20 / L5)	$ 4.4871	$ 4.3441	$ 3.7275	$ 3.7352	$ 3.7862	$ 3.7911	

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Get Gas Surcharge

	Rate R Residential Htg	Rate N Commercial Htg	Total
Original Budget FPFTY Revenue	$189	$0	$189
FPFTY Revenue	$169	$3	$173
Get Gas Revenue Adjustment	($20)	$3	($16)

UGI Utilities Inc.- Gas Division
Fully Projected Future Test Year Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for GDE Rider

	OCT 2022	NOV 2022	DEC 2022	JAN 2023	FEB 2023	MAR 2023	APR 2023	MAY 2023	JUN 2023	JUL 2023	AUG 2023	SEP 2023	TOTAL
Original FPFTY Budget DS GDE Calculation	$2.9	$4.8	$7.5	$9.5	$8.7	$7.2	$4.1	$2.5	$1.8	$1.6	$1.6	$1.9	$54.0
Correct FPFTY Budget DS GDE Calculation	$2.9	$4.8	$7.4	$9.5	$8.7	$7.1	$4.1	$2.5	$1.8	$1.6	$1.6	$1.9	$53.8
Variance to correct Original FPFTY Budget Calculation	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	($0.2)
Original Budget FPFTY DS Rate	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
FPFTY DS Rate	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	
DS Rate Variance	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
DS Rate Volumes	515	859	1,333	1,701	1,554	1,275	740	444	323	279	283	338	9,646
DS Revenue Adjustment	$0	$1	$1	$1	$1	$1	$0	$0	$0	$0	$0	$0	$6
Original Budget FPFTY LFD Rate	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
FPFTY LFD Rate	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	$0.0062	
LFD Rate Variance	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
LFD Rate Volumes	1,836	2,170	2,487	2,761	2,467	2,275	1,911	1,700	1,546	1,494	1,536	1,593	23,775
LFD Revenue Adjustment	$1	$1	$1	$2	$1	$1	$1	$1	$1	$1	$1	$1	$14
Total Revenue Adjustment	$1	$2	$2	$3	$2	$2	$2	$1	$1	$1	$1	$1	$20

UGI Utilities Inc.- Gas Division
Fully Projected Future Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for DSIC

	@ 0% Unadjusted 2023 TOTAL	@ 5% Adjusted 2023 TOTAL	Revenue Adjustment Total
RES. G	$0	$289	$289
H	$0	$15,433	$15,433
SUBTOTAL R	$0	$15,722	$15,722
RT	$0	$2,247	$2,247
TOTAL	$0	$17,970	$17,970
COM. G	$0	$177	$177
H	$0	$3,656	$3,656
SUBTOTAL C-N	$0	$3,832	$3,832
NT	$0	$2,444	$2,444
DS	$0	$1,292	$1,292
IS	$0	$463	$463
XD-F	$0	$73	$73
XD-I	$0	$31	$31
LFD	$0	$801	$801
TOTAL	$0	$8,937	$8,937
IND.	$0	$143	$143
SUBTOTAL I-N	$0	$143	$143
NT	$0	$191	$191
DS	$0	$313	$313
IS	$0	$500	$500
XD-F	$0	$889	$889
XD-I	$0	$55	$55
LFD	$0	$1,328	$1,328
TOTAL	$0	$3,420	$3,420
GRAND TOTAL	$0	$30,327	$30,327

UGI GAS

EXHIBIT SAE-5(a) – (k)

UGI Utilities Inc.- Gas Division
Future Test Year 2022 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Budget 2022	339,581	991,527	619,606	
Adjustment for Customer/Contract Changes	(199)	16	(90)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(b)/(b)(1
Adjustment for Normalized & Annualized Use/Customer	(1,282)	(15,375)	(5,699)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(c)
Adjustment for PGC		55,658	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(d)
Adjustment for MFC		916	916	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(e)
Adjustment for USP		1,102	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(f)
Adjustment for GPC		(93)	(93)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(g)
Adjustment for Excess Take		(1,700)	(1,700)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(h)
Adjustment for EEC Rider		3,765	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(i)
Adjustment for Get Gas		3	3	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(j)
Adjustment for GDE		20	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-5(k)
Future Test Year 2022	338,100	1,035,839	612,942	

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total *	[9] Rates LFD, XD, IS Transport-Other **	[10] Grand Total
1	FTY Revenues (Unadjusted)	$ 8,243	$ 566,726	$ 45,977	$ 7,795	$ 161,780	$ 7,778	$ 54,191	$ 33,462	$ 105,574	$ 991,527
2	FTY PGC Revenues	$ (2,218)	$ (269,556)	$ (3,110)	$ (4,015)	$ (87,391)	$ (4,449)	$ 32	(642)	(571)	(371,921)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 6,025	$ 297,171	$ 42,867	$ 3,781	$ 74,389	$ 3,329	$ 54,223	$ 32,820	$ 105,002	$ 619,606
4	FTY Average Effective Customers (Unadjusted)	23,843	504,315	80,279	3,301	47,006	662	18,617	1,393	1,022	680,439
5	FTY Average Annual Margin Per Customer (L3 / L4 or Weighted Value by District)	$ 0.253	$ 0.589	$ 0.534	$ 1.160	$ 0.878	$ 4.689	$ 2.913	$ 25.929	$ 102.730	$ 0.911
6	FTY Customers (Fully Adjusted)	23,563	504,723	80,279	3,297	46,979	658	18,617	1,392	1,021	680,529
7	Change in Customers during FTY (L6 - L4)	(280)	408	-	(4)	(27)	(4)	-	(1)	(1)	90
8	Annualization of Margin (L5 * L7)	$ (71)	$ 240	$ -	$ (5)	$ (24)	$ (21)	$ -	$ (11)	$ (199)	$ (90)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4 or Weighted Value by District)	$ 0.346	$ 1.124	$ 0.573	$ 2.376	$ 2.750	$ 11.419	$ 2.911	$ 26.405	$ 103.288	$ 1.457
10	Annualization of Total FTY Revenue (L7 * L9)	$ (97)	$ 458	$ -	$ (10)	$ (74)	$ (50)	$ -	$ (11)	$ (199)	$ 16
11	Annualization Adjustment for FTY PGC Revenues (L10 - L8)	$ (26)	$ 218	$ -	$ (5)	$ (51)	$ (30)	$ -	$ -	$ -	$ 106
12	Total FTY UPC (Unadjusted) - MCF	15.80	90.90	82.10	225.10	343.90	1,242.50	708.00	6,904.90		
13	Annualization Adjustment for FTY Sales - MMCF (L7 * L12)/1000	(4)	37	-	(1)	(9)	(5)	-	$ (3)	(213)	(199)

Notes:
* Adjustments for Rates DS are by customer and not in aggregate
** Column [9] further detailed on UGI Gas Exhibit SAE-5(b)(1)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	FTY Revenues (Unadjusted)	$ 46,149	$ 35,603	$ 1,902	$ 21,920	$ 105,574
2	FTY PGC Revenues	(571)	-	-	-	(571)
3	FTY Revenues net of PGC - Margin (Unadjusted)	$ 45,578	$ 35,603	$ 1,902	$ 21,920	$ 105,002
4	FTY Average Effective Customers (Unadjusted)	603	56	57	306	1,022
5	FTY Average Annual Margin Per Customer (L3 / L4)	$ 75.579	$ 635.766	$ 33.364	$ 71.616	$ 102.730
6	FTY Customers (Fully Adjusted)	604	56	57	304	1,021
7	Change in Customers during FTY (L6 - L4)	1	-	-	(2)	(1)
8	Annualization of Margin	$ (238)	$ 78	$ -	$ (39)	$ (199)
9	Average Annual Revenue Per Customer (L1 / L4)	$ 76.526	$ 635.766	$ 33.364	$ 71.616	$ 103.288
10	Annualization of Total FTY Revenue	$ (238)	$ 78	$ -	$ (39)	$ (199)
11	Annualization of FTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total FTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for FTY Sales - MMCF	(136)	-	-	(77)	(213)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
FTY (Unadjusted) Use/Customer ("UPC") - MCF	15.80	90.90	82.10	225.10	343.90	1,242.50	708.00	6,904.90		
FTY UPC (Fully Adjusted) - MCF	16.30	88.30	82.90	215.10	343.60	1,116.70	712.50	6,904.90		
Change in UPC - MCF (L2 - L1)	0.50	(2.60)	0.80	(10.00)	(0.30)	(125.80)	4.50	0.00		
FPFTY Customers (Fully Adjusted)	23,563	504,723	80,279	3,297	46,979	658	18,617	1,392	1,021	680,529
Annualization Adjustment for Sales - MMCF (L3 * L4)/1000)	12	(1,312)	64	(33)	(14)	(83)	85	-	-	(1,282)
Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 133	$ (14,796)	$ 312	$ (330)	$ (141)	$ (832)	$ 278	$ -	$ -	$ (15,375)
Total Unit Revenue Adjustment (L6 / L5)	$ 11.2748	$ 11.2748	$ 4.8566	$ 10.0198	$ 9.9848	$ 10.0461	$ 3.2923	$ -	$ -	
Distribution Margin Adjustment (L5 * L9)	$ 48	$ (5,394)	$ 264	$ (118)	$ (50)	$ (297)	$ 266	$ -	$ -	$ (5,280)
Distribution Unit Rate (Rate N/NT Weighted Value by District)	$ 4.1104	$ 4.1104	$ 4.1104	$ 3.5647	$ 3.5309	$ 3.5884	$ 3.1483	$ -	$ -	
PGC Revenue (L5 * L11)	$ 74	$ (8,237)	$ -	$ (207)	$ (88)	$ (520)	$ -	$ -	$ -	$ (8,978)
PGC Unit Rate	$ 6.2767	$ 6.2767		$ 6.2767	$ 6.2767	$ 6.2767				
EE&C Revenue Adjustment (L5 * L13)	$ 2	$ (273)	$ 13	$ (1)	$ (0)	$ (2)	$ 2	$ -	$ -	$ (258)
EE&C Unit Rate	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0556	$ -	
USP Revenue Adjustment (L5 * L15)	$ 4	$ (467)	$ 23	$ -	$ -	$ -	$ -	$ -	$ -	$ (440)
USP Unit Rate	$ 0.3562	$ 0.3562	$ 0.3562	$ -	$ -	$ -	$ -	$ -	$ -	
MFC Revenue/Margin Adjustment (L5 * L17)	$ 2	$ (179)	$ -	$ (1)	$ (0)	$ (1)	$ -	$ -	$ -	$ (179)
MFC Unit Rate	$ 0.1362	$ 0.1362		$ 0.0176	$ 0.0176	$ 0.0176	$ -	$ -	$ -	
DSIC Revenue/Margin Adjustment (L8 + L12 + L14 + L16) * L19	$ 2	$ (246)	$ 12	$ (5)	$ (2)	$ (12)	$ 10	$ -	$ -	$ (240)
DSIC Unit Rate	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ 0.0390	$ -	
Total Margin Adjustment (L8 + L16 + L18)	$ 52	$ (5,819)	$ 276	$ (123)	$ (52)	$ (310)	$ 277	$ -	$ -	$ (5,699)
Total Unit Margin Adjustment (L20 / L5)	$ 4.4342	$ 4.4342	$ 4.2927	$ 3.7227	$ 3.6877	$ 3.7474	$ 3.2719	$ -	$ -	

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for PGC

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original Budget PGC Rate FPFTY (Weighted Value by District)	$4.8790	$4.8790	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	
FPFTY PGC Rate	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	
PGC Rate Variance	$1.3977	$1.3977	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	
Total PGC Volumes	3,646	7,286	10,139	12,933	10,412	8,571	4,413	1,988	1,145	926	994	1,516	63,969
PGC Revenue Adjustment	$5,096	$10,184	$7,719	$9,846	$7,927	$6,526	$3,360	$1,514	$871	$705	$756	$1,154	$55,658

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for MFC

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original Budget PGC Rate FTY	$4.8790	$4.8790	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	$5.5154	
FTY PGC Rate	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	$6.2767	
PGC Rate Variance	$1.3977	$1.3977	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	$0.7613	
Total PGC Volumes-Rate R	2,639	5,270	7,327	9,339	7,526	6,201	3,196	1,438	824	666	714	1,094	
Total PGC Volumes-Rate N	1,007	2,016	2,812	3,594	2,886	2,371	1,217	551	320	261	279	421	
Total PGC Volumes	3,646	7,286	10,139	12,933	10,412	8,571	4,413	1,988	1,145	926	994	1,516	63,969
Rate R %	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	
Rate N %	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	
MFC Rate R Adj Rate	$0.03	$0.03	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	
MFC Rate N Adj Rate	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Rate R Revenue Variance	$80	$160	$121	$154	$124	$102	$53	$24	$14	$11	$12	$18	
Rate N Revenue Variance	$4	$8	$6	$8	$6	$5	$3	$1	$1	$1	$1	$1	
Total Revenue Variance	$84	$168	$127	$162	$130	$107	$55	$25	$14	$12	$12	$19	$916

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for USP

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original FTY Budget USP Calculation	$969	$1,922	$2,653	$3,361	$2,722	$2,252	$1,171	$524	$294	$234	$253	$396	$16,751
Correct FTY Budget USP Calculation	$920	$1,823	$2,517	$3,189	$2,583	$2,137	$1,111	$497	$279	$222	$240	$375	$15,893
Variance to correct Original FTY Budget Calculation	($50)	($98)	($136)	($172)	($139)	($115)	($60)	($27)	($15)	($12)	($13)	($20)	($857)
Original Budget USP Rate FTY	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	$0.3171	
FTY USP Rate	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	$0.3562	
USP Rate Variance	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	$0.0391	
Total Rate R Volumes	3,057	6,060	8,368	10,599	8,585	7,102	3,694	1,652	927	738	796	1,247	52,825
Total Rate R excl CAP Volumes	2,901	5,750	7,939	10,056	8,145	6,738	3,505	1,568	880	700	756	1,184	50,121
USP Rate Revenue Variance	$113	$225	$310	$393	$318	$263	$137	$61	$34	$27	$30	$46	$1,960
Total Revenue Variance	$64	$126	$175	$221	$179	$148	$77	$34	$19	$15	$17	$26	$1,102

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for GPC

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
GPC Rate	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to Original FTY Budget	(81)	(161)	(224)	(285)	(230)	(189)	(98)	(44)	(25)	(20)	(22)	(33)	(1,414)
Revenue Variance	($5)	($11)	($15)	($19)	($15)	($13)	($6)	($3)	($2)	($1)	($1)	($2)	($93)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)		(283)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(1,700)

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for EEC Rider

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original FTY Budget DS EEC Calculation	$ 31.5	$ 52.5	$ 81.4	$ 103.9	$ 94.8	$ 77.8	$ 45.1	$ 27.0	$ 19.5	$ 16.9	$ 17.1	$ 20.5	$ 588.1
Correct FTY Budget DS EEC Calculation	$ 31.3	$ 52.3	$ 81.1	$ 103.4	$ 94.4	$ 77.5	$ 44.9	$ 26.9	$ 19.5	$ 16.8	$ 17.1	$ 20.5	$ 585.7
Variance to correct Original FTY Budget Calculation	$ (0.2)	$ (0.3)	$ (0.4)	$ (0.5)	$ (0.4)	$ (0.3)	$ (0.2)	$ (0.1)	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)	$ (2.4)
Original Budget FTY R/RT Rate	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	$ 0.1547	
FTY R/RT Rate	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	$ 0.2077	
R/RT Rate Variance	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	$ 0.0530	
R/RT Rate Volumes	3,057	6,060	8,368	10,599	8,585	7,102	3,694	1,652	927	738	796	1,247	52,825
R/RT Revenue Adjustment	$ 162	$ 321	$ 443	$ 562	$ 455	$ 376	$ 196	$ 88	$ 49	$ 39	$ 42	$ 66	$ 2,800
Original Budget FTY N/NT Rate	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	
FTY N/NT Rate	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0204	
N/NT Rate Variance	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	$ 0.0228	
N/NT Rate Volumes	1,824	3,463	4,745	6,000	4,858	4,027	2,159	1,071	692	594	624	858	30,917
N/NT Revenue Adjustment	$ 42	$ 79	$ 108	$ 137	$ 111	$ 92	$ 49	$ 24	$ 16	$ 14	$ 14	$ 20	$ 705
Original Budget FTY DS Rate	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	$ 0.0609	
FTY DS Rate	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	$ 0.0556	
DS Rate Variance	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	$ (0.0053)	
DS Rate Volumes	514	859	1,331	1,699	1,551	1,272	737	442	320	276	281	336	9,618
DS Revenue Adjustment	$ (3)	$ (5)	$ (7)	$ (9)	$ (8)	$ (7)	$ (4)	$ (2)	$ (2)	$ (1)	$ (1)	$ (2)	$ (51)
Original Budget FTY LFD Rate	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	$ 0.0184	
FTY LFD Rate	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	$ 0.0316	
LFD Rate Variance	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	$ 0.0132	
LFD Rate Volumes	1,837	2,171	2,487	2,761	2,469	2,278	1,913	1,702	1,548	1,497	1,538	1,595	23,797
LFD Revenue Adjustment	$ 24	$ 29	$ 33	$ 36	$ 33	$ 30	$ 25	$ 22	$ 20	$ 20	$ 20	$ 21	$ 314
Total Revenue Adjustment	$ 225	$ 424	$ 577	$ 726	$ 590	$ 491	$ 266	$ 132	$ 84	$ 71	$ 75	$ 105	$ 3,765

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Get Gas Surcharge

	Rate R Residential Htg	Rate N Commercial Htg	Total
Original Budget FTY Revenue	$ 142	$ -	$ 142
FTY Revenue	$ 142	$ 3	$ 145
Get Gas Revenue Adjustment	$ (0)	$ 3	$ 3

UGI Utilities Inc.- Gas Division
Future Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for GDE Rider

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Original FTY Budget DS GDE Calculation	$ 2.89	$ 4.83	$ 7.49	$ 9.55	$ 8.72	$ 7.16	$ 4.15	$ 2.48	$ 1.80	$ 1.55	$ 1.58	$ 1.89	$ 54.08
Correct FTY Budget DS GDE Calculation	$ 2.03	$ 3.44	$ 5.50	$ 7.28	$ 6.48	$ 5.43	$ 3.07	$ 1.84	$ 1.34	$ 1.17	$ 1.16	$ 1.38	$ 40.06
Variance to correct Original FTY Budget Calculation	$ (0.01)	$ (0.02)	$ (0.03)	$ (0.04)	$ (0.03)	$ (0.03)	$ (0.01)	$ (0.00)	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ (0.22)
Original Budget FTY DS Rate	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	
FTY DS Rate	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	
DS Rate Variance	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	
DS Rate Volumes	514	859	1,331	1,699	1,551	1,272	737	442	320	276	281	336	9,618
DS Revenue Adjustment	$ 0	$ 1	$ 1	$ 1	$ 1	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 6
Original Budget FTY LFD Rate	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$ 0.0056	
FTY LFD Rate	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	$ 0.0062	
LFD Rate Variance	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	
LFD Rate Volumes	1,837	2,171	2,487	2,761	2,469	2,278	1,913	1,702	1,548	1,497	1,538	1,595	23,797
LFD Revenue Adjustment	$ 1	$ 1	$ 1	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 14
Total Revenue Adjustment	$ 1	$ 2	$ 2	$ 3	$ 2	$ 2	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	$ 20

UGI GAS

EXHIBIT SAE-6(a) – (k)

UGI Utilities Inc.- Gas Division
Historic Year 2021 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Margin ($000's)	Reference
Actual 2021	308,784	844,210	553,517	
Adjustment for Customer/Contract Changes	547	(1,072)	(648)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(b)/(b)(1)
Adjustment for Normalized & Annualized Use/Customer	7,441	50,112	27,356	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(c)
Adjustment for PGC		48,477	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(d)
Adjustment for MFC		797	797	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(e)
Adjustment for USP		2,852	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(f)
Adjustment for GPC		265	265	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(g)
Adjustment for Excess Take		(1,047)	(1,047)	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(h)
Adjustment for EEC Rider		(574)	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(i)
Adjustment for Get Gas		13	13	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(j)
Adjustment for GDE		(31)	0	UGI Utilities, Inc.- Gas Division-Exhibit SAE-6(k)
Historic Year 2021	316,771	944,002	580,253	

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Customer/Contract Changes

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other *	[10] Grand Total
1	HTY Revenues (Unadjusted)	$ 12,583	$ 451,891	$ 41,749	$ 6,967	$ 127,346	$ 6,641	$ 49,541	$ 46,750	$ 100,742	$ 844,210
2	HTY PGC Revenues	$ (1,868)	$ (196,813)	$ (2,773)	$ (2,902)	$ (62,639)	$ (3,483)	$ (227)	(17,018)	(2,968)	(290,692)
3	HTY Revenues net of PGC - Margin (Unadjusted)	$ 10,714	$ 255,078	$ 38,975	$ 4,065	$ 64,707	$ 3,158	$ 49,314	$ 29,732	$ 97,774	$ 553,517
4	HTY Average Effective Customers (Unadjusted)	24,983	497,392	80,835	3,320	46,406	692	18,687	1,375	985	674,675
5	HTY Average Annual Margin Per Customer (L3 / L4 or Weighted Value by District)	$ 0.420	$ 0.383	$ 0.478	$ 0.841	$ 1.412	$ 4.580	$ (3.781)	$ 19.723	$ 99.222	$ 0.844
6	HTY Customers (Fully Adjusted)	24,549	498,946	77,145	3,316	45,954	707	18,690	1,367	988	671,662
7	Change in Customers during HTY (L6 - L4)	(434)	1,554	(3,690)	(4)	(452)	15	3	(8)	3	(3,013)
8	Annualization of Margin (L5 * L7)	$ (182)	$ 596	$ (1,764)	$ (4)	$ (638)	$ 70	$ (11)	$ (154)	$ 1,439	$ (648)
9	Average Annual Revenue Per Customer (Unadjusted) (L1 / L4 or Weighted Value by District)	$ 0.495	$ 0.632	$ 0.512	$ 2.350	$ 2.818	$ 9.642	$ (3.974)	$ 30.986	$ 102.235	$ 1.325
10	Annualization of Total HTY Revenue (L7 * L9)	$ (215)	$ 982	$ (1,889)	$ (10)	$ (1,274)	$ 148	$ (12)	$ (241)	$ 1,439	$ (1,072)
11	Annualization Adjustment for HTY PGC Revenues (L10 - L8)	$ (32)	$ 386	$ (125)	$ (7)	$ (635)	$ 78	$ (1)	$ (88)	$ -	$ (423)
12	Total HTY UPC (Unadjusted) - MCF (Weighted Value by District)	15.57	50.64	75.71	352.20	327.57	1,181.06	273.19	5,292.63		
13	Annualization Adjustment for HTY Sales - MMCF (L7 * L12)/1000	(7)	79	(279)	(2)	(148)	18	1	(41)	926	547

Notes:

* Column [9] further detailed on UGI Gas Exhibit SAE-6(b)(1)

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Customer/Contract Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] IS	[5] TOTAL
1	HTY Revenues (Unadjusted)	$ 43,933	$ 31,889	$ 2,081	$ 22,839	$ 100,742
2	HTY PGC Revenues	(1,148)	(1,071)	(88)	(661)	(2,968)
3	HTY Revenues net of PGC - Margin (Unadjusted)	$ 42,785	$ 30,819	$ 1,993	$ 22,177	$ 97,774
4	HTY Average Effective Customers (Unadjusted)	581	53	56	295	985
5	HTY Average Annual Margin Per Customer (L3 / L4)	$ 73.685	$ 578.729	$ 35.463	$ 75.099	$ 99.222
6	HTY Customers (Fully Adjusted)	589	55	57	287	988
7	Change in Customers during HTY (L6 - L4)	8	2	1	(8)	3
8	Annualization of Margin	$ 594	$ 1,494	$ 108	$ (756)	$ 1,439
9	Average Annual Revenue Per Customer (L1 / L4)	$ 75.662	$ 598.832	$ 37.035	$ 77.338	$ 102.235
10	Annualization of Total HTY Revenue	$ 594	$ 1,494	$ 108	$ (756)	$ 1,439
11	Annualization of HTY PGC Revenues (L10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total HTY UPC (Unadjusted) - MCF					
13	Annualization Adjustment for HTY Sales - MMCF	341	1,139	(88)	(467)	926

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Normalized & Annualized Use/Customer

Line #	Description	[1] Rate R Residential-Non Htg	[2] Rate R Residential-Htg	[3] Rate RT RT	[4] Rate N Commercial-Non Htg	[5] Rate N Commercial-Htg	[6] Rate N Industrial	[7] Rate NT NT Total	[8] Rate DS DS Total	[9] Rates LFD, XD, IS Transport-Other	[10] Total
1	HTY (Unadjusted) Use/Customer ("UPC") - MCF	15.60	82.90	76.80	199.40	314.70	1,177.60	668.80	5,443.70		
2	HTY UPC (Fully Adjusted) - MCF	16.30	88.50	82.90	191.20	340.00	1,273.10	711.40	6,978.00		
3	Change in UPC - MCF (L2 - L1)	0.70	5.60	6.10	(8.20)	25.30	95.50	42.60	1,534.30		
4	HTY Customers (Fully Adjusted)	24,549	498,946	77,145	3,316	45,954	707	18,690	1,367	988	671,662
5	Annualization Adjustment for Sales-MMCF (L3*L4)/1000 (District Weighted)	18	2,847	467	(27)	1,174	69	796	2,097	-	7,441
6	Total Revenue Adjustment (L8 + L10+L12+L14+L16+L18)	$ 175	$ 28,270	$ 2,191	$ (234)	$ 10,207	$ 604	$ 2,884	$ 6,013	$ -	$ 50,112
7	Total Unit Revenue Adjustment (L6/L5)	$ 9.9289	$ 9.9289	$ 4.6877	$ 8.7756	$ 8.6951	$ 8.7505	$ 3.6259	$ 2.8677	$ -	
8	Distribution Margin Adjustment (L5 *L9)	$ 73	$ 11,703	$ 1,922	$ (95)	$ 4,114	$ 246	$ 2,846	$ 5,800	$ -	$ 26,608
9	Distribution Unit Rate (Weighted Value by District)	$ 4.1104	$ 4.1104	$ 4.1104	$ 3.5839	$ 3.5045	$ 3.5592	$ 3.5772	$ 2.7663	$ -	
10	PGC Revenue (L5*L11)	$ 91	$ 14,601	$ -	$ (137)	$ 6,020	$ 354	$ -	$ -	$ -	$ 20,930
11	PGC Unit Rate	$ 5.1283	$ 5.1283		$ 5.1283	$ 5.1283	$ 5.1283				
12	EE&C Revenue Adjustment (L5*L13)	$ 3	$ 440	$ 72	$ 0	$ (3)	$ (0)	$ (2)	$ 128	$ -	$ 638
13	EE&C Unit Rate	$ 0.1547	$ 0.1547	$ 0.1547	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ (0.0024)	$ 0.0609	$ -	
14	USP Revenue Adjustment (L5*L15)	$ 6	$ 1,015	$ 167	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,188
15	USP Unit Rate	$ 0.3565	$ 0.3565	$ 0.3565	$ -	$ -	$ -	$ -	$ -	$ -	
16	MFC Revenue/Margin Adjustment (L5*L17)	$ 2	$ 317	$ -	$ (0)	$ 17	$ 1	$ - 0	$ -	$ -	$ 336
17	MFC Unit Rate	$ 0.1113	$ 0.1113	$ -	$ 0.0144	$ 0.0144	$ 0.0144	$ -	$ -	$ -	
18	DSIC Revenue/Margin Adjustment (L8+L12+L14+L16)*L19	$ 1	$ 193	$ 31	$ (1)	$ 59	$ 4	$ 41	$ 85	$ -	$ 411
19	DSIC Unit Rate	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ 0.0143	$ -	
20	Total Margin Adjustment (L8+L16+L18)	$ 76	$ 12,213	$ 1,952	$ (97)	$ 4,190	$ 250	$ 2,886	$ 5,885	$ -	$ 27,356
21	Total Unit Margin Adjustment (L20/L5)	$ 4.2894	$ 4.2894	$ 4.1765	$ 3.6497	$ 3.5692	$ 3.6246	$ 3.6283	$ -	$ -	

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for PGC

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
PGC Rate HTY	$4.3631	$4.3631	$4.2426	$4.2426	$4.2426	$4.2426	$4.2426	$4.2426	$4.4594	$4.4594	$4.4594	$5.1283	
September HTY PGC Rate	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	
PGC Rate Variance	$0.7652	$0.7652	$0.8857	$0.8857	$0.8857	$0.8857	$0.8857	$0.8857	$0.6689	$0.6689	$0.6689	$0.0000	
Total PGC Volumes	2,541	6,005	9,124	11,357	10,641	7,357	4,123	2,278	1,080	1,099	1,089	1,036	57,732
PGC Revenue Adjustment	$1,944	$4,595	$8,081	$10,059	$9,425	$6,516	$3,652	$2,018	$723	$735	$729	$0	$48,477

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for MFC

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
PGC Rate HTY	$4.3631	$4.3631	$4.2426	$4.2426	$4.2426	$4.2426	$4.2426	$4.2426	$4.4594	$4.4594	$4.4594	$5.1283	
September HTY PGC Rate	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	$5.1283	
PGC Rate Variance	$0.7652	$0.7652	$0.8857	$0.8857	$0.8857	$0.8857	$0.8857	$0.8857	$0.6689	$0.6689	$0.6689	$0.0000	
Total PGC Volumes-Rate R	1,924	4,490	6,611	8,171	7,697	5,203	2,972	1,606	773	757	732	702	
Total PGC Volumes-Rate N	617	1,515	2,513	3,186	2,945	2,154	1,152	672	307	342	358	334	
Total PGC Volumes	2,541	6,005	9,124	11,357	10,641	7,357	4,123	2,278	1,080	1,099	1,089	1,036	57,732
Rate R %	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	
Rate N %	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	0.28%	
MFC Rate R Adj Rate	$0.0166	$0.0166	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0192	$0.0145	$0.0145	$0.0145	$0.0000	
MFC Rate N Adj Rate	$0.0021	$0.0021	$0.0025	$0.0025	$0.0025	$0.0025	$0.0025	$0.0025	$0.0019	$0.0019	$0.0019	$0.0000	
Rate R Revenue Variance	$31.954	$74.562	$127.058	$157.039	$147.925	$99.994	$57.112	$30.872	$11.223	$10.992	$10.621	$0.000	
Rate N Revenue Variance	$1.321	$3.245	$6.233	$7.902	$7.303	$5.342	$2.856	$1.667	$0.575	$0.640	$0.670	$0.000	
Total Revenue Variance	$33	$78	$133	$165	$155	$105	$60	$33	$12	$12	$11	$0	$797

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for USP

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
USP Rate HTY	$0.2726	$0.2726	$0.2948	$0.2948	$0.2948	$0.2948	$0.2948	$0.2948	$0.3171	$0.3171	$0.3171	$0.3565	
September HTY USP Rate	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	$0.3565	
USP Rate Variance	$0.0839	$0.0839	$0.0617	$0.0617	$0.0617	$0.0617	$0.0617	$0.0617	$0.0394	$0.0394	$0.0394	$0.0000	
Total Rate R Volumes	2,205	5,166	7,616	9,415	8,875	5,970	3,400	1,834	889	868	841	806	47,884
Total Rate R excl CAP Volumes	2,083	4,895	7,218	8,923	8,411	5,657	3,221	1,737	842	823	797	764	45,370
USP Rate Revenue Variance	$175	$411	$445	$551	$519	$349	$199	$107	$33	$32	$31	$0	$2,852
Total Revenue Variance	$175	$411	$445	$551	$519	$349	$199	$107	$33	$32	$31	$0	$2,852

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for GPC

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
GPC Rate HTY	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	$0.0660	
Volume Variance to HTY	174	418	640	797	747	515	286	160	71	73	73	69	4,022
Revenue Variance	$12	$28	$42	$53	$49	$34	$19	$11	$5	$5	$5	$5	$265

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MMCF)	(175)
$/MCF	$6.00
Excess Take Revenue/Margin	($1,047)

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for EEC Rider

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
Original HTY R/RT Rate	$0.2245	$0.2245	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	
September HTY R/RT Rate	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	$0.1547	
R/RT Rate Variance	($0.0698)	($0.0698)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
R/RT Rate Volumes	2,205	5,166	7,616	9,415	8,875	5,970	3,400	1,834	889	869	841	806	47,886
R/RT Revenue Adjustment	($154)	($361)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($514)
Original HTY N/NT Rate	$0.0425	$0.0425	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
September HTY N/NT Rate	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
N/NT Rate Variance	($0.0449)	($0.0449)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
N/NT Rate Volumes	1,259	2,736	4,288	5,440	5,070	3,604	2,067	1,253	661	723	764	743	28,608
N/NT Revenue Adjustment	($57)	($123)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($179)
Original HTY DS Rate	$0.0004	$0.0004	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	
September HTY DS Rate	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	$0.0609	
DS Rate Variance	$0.0605	$0.0605	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	667	832	1,355	1,498	1,366	1,064	646	422	279	274	266	314	8,983
DS Revenue Adjustment	$40	$50	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$91
Original HTY LFD Rate	$0.0103	$0.0103	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	
September HTY LFD Rate	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	$0.0184	
LFD Rate Variance	$0.0081	$0.0081	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	1,685	1,874	2,341	2,574	2,411	2,253	1,864	1,636	1,469	1,408	1,483	1,519	22,516
LFD Revenue Adjustment	$14	$15	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$29
Total Revenue Adjustment	($156)	($418)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($574)

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for Get Gas Surcharge

	Rate R Residential Htg	Rate N Commercial Htg	Total
HTY Revenue	$98	$2	$100
HTY Annualized Revenue	$110	$2	$113
Get Gas Revenue Adjustment	$12	$1	$13

UGI Utilities Inc.- Gas Division
Historic Period- 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment for GDE Rider

	OCT 2020	NOV 2020	DEC 2020	JAN 2021	FEB 2021	MAR 2021	APR 2021	MAY 2021	JUN 2021	JUL 2021	AUG 2021	SEP 2021	TOTAL
Original HTY DS Rate	$0.0117	$0.0117	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
September HTY DS Rate	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
DS Rate Variance	($0.0061)	($0.0061)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
DS Rate Volumes	667	832	1,355	1,498	1,366	1,064	646	422	279	274	266	314	8,983
DS Revenue Adjustment	($4)	($5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($9)
Original HTY LFD Rate	$0.0117	$0.0117	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
September HTY LFD Rate	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	$0.0056	
LFD Rate Variance	($0.0061)	($0.0061)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
LFD Rate Volumes	1,685	1,874	2,341	2,574	2,411	2,253	1,864	1,636	1,469	1,408	1,483	1,519	22,516
LFD Revenue Adjustment	($10)	($11)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($22)
Total Revenue Adjustment	($14)	($17)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($31)

UGI GAS

EXHIBIT SAE-7(a) – (c)

Detail for Usage per Customer for FPFTY by Class as shown on UGI Gas Exhibit SAE-4(c)

Residential Non-Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	16.4	26,531	435,108
Rate R	16.3	22,732	370,905
Rate RT	16.9	3,799	64,203

Residential Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	87.8	589,601	51,766,968
Rate R	88.0	513,121	45,174,392
Rate RT	86.2	76,480	6,592,576
Rate RT Total	82.9	80,279	6,656,779

Commercial Non-Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	328.1	4,734	1,553,225
Rate N	215.1	3,295	708,677
Rate NT	492.0	1,415	696,180
Rate DS	6,182.0	24	148,368

Commercial Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	542.9	65,470	35,543,663
Rate N	346.0	47,558	16,455,725
Rate NT	689.5	16,746	11,546,367
Rate DS	6,467.9	1,166	7,541,571
Rate Commercial NT Total	674.1	18,161	12,242,547

Industrial

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	2,796.5	1,313	3,671,805
Rate N	1,109.5	655	726,725
Rate NT	2,242.6	456	1,022,626
Rate DS	9,517.1	202	1,922,454
Rate NT Total	712.5	18,617	13,265,173
Rate DS Total	6,905.5	1,392	9,612,394

Detail for Usage per Customer for FTY by Class as shown on UGI Gas Exhibit SAE-5(c)

Residential Non-Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	16.4	27,362	448,737
Rate R	16.3	23,563	384,534
Rate RT	16.9	3,799	64,203

Residential Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	88.0	581,203	51,145,864
Rate R	88.3	504,723	44,553,288
Rate RT	86.2	76,480	6,592,576
Rate RT Total	82.9	80,279	6,656,779

Commercial Non-Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	328.1	4,736	1,553,882
Rate N	215.1	3,297	709,334
Rate NT	492.0	1,415	696,180
Rate DS	6,182.0	24	148,368

Commercial Heating

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	542.9	64,891	35,229,324
Rate N	343.6	46,979	16,142,435
Rate NT	689.5	16,746	11,546,367
Rate DS	6,467.0	1,166	7,540,522
Rate Commercial NT Total	674.1	18,161	12,242,547

Industrial

	(1)	(2)	(3)
	UPC	Fully Adj Cust	Fully Adj Sales
Total	2,796.5	1,316	3,680,194
Rate N	1,116.7	658	734,811
Rate NT	2,242.6	456	1,022,626
Rate DS	9,518.6	202	1,922,757
Rate NT Total	712.5	18,617	13,265,173
Rate DS Total	6,904.9	1,392	9,611,647

Detail for Usage per Customer for HTY by Class as shown on UGI Gas Exhibit SAE-6(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	16.4	28,152	461,693
Rate R	16.3	24,512	400,177
Rate RT	16.9	3,640	61,516

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	88.2	572,451	50,490,178
Rate R	88.5	498,946	44,154,047
Rate RT	86.2	73,505	6,336,131
Rate RT Total	82.9	77,145	6,397,647

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	328.1	4,723	1,549,616
Rate N	191.2	3,303	631,375
Rate NT	492.0	1,393	685,356
Rate DS	8,625.4	27	232,886

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	542.9	63,970	34,729,313
Rate N	340.0	45,954	15,625,797
Rate NT	689.5	16,856	11,622,212
Rate DS	6,449.4	1,160	7,481,304
Rate Commercial NT Total	674.4	18,249	12,307,568

Industrial

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	2,796.5	1,328	3,713,752
Rate N	1,273.1	707	900,069
Rate NT	2,242.6	441	988,987
Rate DS	10,137.2	180	1,824,696
Rate NT Total	711.4	18,690	13,296,555
Rate DS Total	6,978.0	1,367	9,538,886

UGI GAS

EXHIBIT SAE-8

UGI Utilities, Inc. - Gas Division
No Notice Service (NNS) Rate Calculation

Notes:

1/ Storage Trip Cost ($/mcf) 0.1330

2/ Weekend Load Reduction Factor (%) 15.0%

WELF = Weekend Load Reduction Factor
WD = Weekday Day Use
WE = Weekend Day Use
AVERAGE = Average Daily Use

3/ EQ #1 **WD = (1/(1 - WELF)) * WE**
= (1/(1 - 0.15)) * WE
WD = 1.18 * WE

EQ #2 **AVERAGE = [(5 * WD) + (2 * WE)] / 7**
Step 1 AVERAGE = [5 * ((1/ (1 - WELF)) * WE)) + (2 * WE)] / 7
= [5 * (1/(1 - WELF)) + 2] * WE] / 7
= [5 * (1/(1 - 0.15)) + 2] * WE] / 7
7.90 * WE / 7
Step 2 WE = 0.89 * AVERAGE

4/ EQ #3 **Wkly Imbalance = 5 x (WD - AVERAGE) + 2 (AVERAGE - WE)**
= (5 * WD) - (3 * AVERAGE) - (2 * WE)
= (5 * (1/(1-WELF) * WE) - (3 * AVERAGE) - (2 * WE)
= [(5 * (1/(1-WELF)) - 2) * WE] - (3 * AVERAGE)
= [(5 * (1/(1-0.15)) - 2) * WE] - (3 * AVERAGE)
3.90 * WE - (3 * AVERAGE)
0.47 * AVERAGE

EQ #4 **Unit Cost Calculation ($/mcf)**
= [(Wkly Imbalance) / (7 * AVERAGE)] * STORAGE TRIP COST
= [(0.47 x Average) / (7 x AVERAGE)] x 0.133
0.07 x 0.133
0.0093

EQ #5 **Per Unit of Demand Calculation ($/mcf per month)**
= Unit Cost Demand x 20 days
= 0.0093 x 20
0.1860

Notes:

1/ Weighted average of storage trip costs based on SCQ of storages

2/ Aggregate load reduction for all non-Choice transportation customers electing NNS
Weekend Load Reduction factor percentage based on historical data for the period Nov 2020 through Oct 2021

3/ Assumes WD use approximately equal for all weekdays (work week)
Assumes WE use approximately equal for all weekend days

4/ Assumes levelized deliveries on all days

UGI GAS

EXHIBIT SAE-9

UGI Utilities, Inc. - Gas Division
Monthly Balancing Service (MBS) Rate Calculation

Notes:

1/	Average Capacity Charge for Storage ($/mcf)	1.2920	(A)
2/	Anticipated Average Monthly Imbalance %	2.5737%	(B)
3/	Load Factors & MBS Rate Calculation		

Rate	Load Factor	
DS	27.2%	(C)
LFD	56.1%	(C)
XD Firm	63.1%	(C)
Transportation System Average	55.4%	(D)

MBS Rate Formula
E = [(A / D) - ((A / D) * C)] * B

Rate	MBS Rate ($/mcf)	
DS	0.0437	(E)
LFD	0.0263	(E)
XD Firm	0.0221	(E)

1/ Weighted average of storage capacity and demand costs based on SCQ of storages
2/ Average monthly imbalance percentage includes all non-Choice transportation customers electing MBS
Average monthly imbalance percentage based on historical data for the period Nov 2020 through Oct 2021
3/ Load Factors based on FPFTY throughput and peak capacity for applicable customers by rate class

UGI GAS

EXHIBIT SAE-10

UGI Utilities, Inc. - Gas Division
Merchant Function Charge (MFC) Calculation

		Rate R/RT	Rate N/NT
Total Uncollectible Revenue Requirement	$ 17,957,980		
Allocator 1/		92.51%	6.47%
Uncollectible Revenue Requirement		$ 16,612,927	$ 1,161,881
Total Proposed Revenue		$ 730,289,390	$ 265,365,525
MFC % 2/		2.27%	0.44%

1/ The allocator is based on a 3-year average of uncollectible expenses.
2/ The MFC will be applied to bills of customers in Rate Schedules R & N only.

UGI GAS STATEMENT NO. 9

TIMOTHY J. ANGSTADT

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. - Gas Division

Statement No. 9

Direct Testimony of
Timothy J. Angstadt

Topics Addressed:	**System Operations** **Operational Response to COVID-19** **System Reliability** **Leak Reductions & Emergency Response** **Employee Additions** **Safety Initiatives** **Environmental Remediation & Programs**

Dated: January 28, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy J. Angstadt. My current business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom are you employed and in what capacity?

A. I am employed as the Vice President of Operations by UGI Utilities, Inc. ("UGI"). UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two (2) operating divisions, the Gas Division ("UGI Gas" or the "Company) and the Electric Division ("UGI Electric"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Gas Exhibit TJA-1 to my testimony.

Q. What are your responsibilities as Vice President of Operations?

A. As Vice President – Operations, I am UGI's senior executive accountable for over 850 individuals including management, engineering, clerical, and field technicians to operate and maintain the Company's transmission and distribution systems. I am also responsible for overseeing activities and personnel involved with the Company's integrity programs (e.g., leak survey, corrosion control, Geographic Information System ("GIS") mapping, network analysis, safety, Distribution Integrity Management Program ("DIMP"), Transmission Integrity Management Program ("TIMP"), and technical training).

Additionally, I am an executive sponsor of UGI's Safety Culture Initiative and oversee accelerated infrastructure replacement initiatives, customer growth opportunities, capacity constraint improvements, and major installation projects.

Q. Have you presented testimony in proceedings before the Commission?

A. Yes. UGI Gas Exhibit TJA-1 identifies my prior testimony.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. In my testimony, I will address the following topics: (1) natural gas system operations; (2) response to the COVID-19 Pandemic; (3) system safety and reliability; (4) leak reductions and emergency response; (5) employee additions; and (6) safety initiatives and environmental remediation.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. Please see UGI Gas Exhibit TJA-1.

II. <u>NATURAL GAS SYSTEM OPERATIONS</u>

Q. Please provide an overview of the Company's distribution system.

A. UGI Gas provides service to approximately 672,000 residential, commercial, and industrial customers located in forty-five (45) of Pennsylvania's sixty-seven (67) counties and spanning more than 700 municipalities. As of December 31, 2021, the Company operates more than 12,000 miles of gas distribution mains and 300 miles of natural gas transmission mains in the Commonwealth of Pennsylvania.

Q. Please describe UGI Gas's operations centers and support facilities.

A. UGI Gas has operations centers and support facilities throughout its service territory. Additionally, a stand-alone centralized training facility in Reading includes a "safety town" for real-life outdoor training inclusive of leak pinpointing and investigation, a separate welding and tapping center, a safety lab, a service lab, a measurement and regulation lab, and a computer lab. Classrooms and laboratories provide four primary training deliverables: (1) safety; (2) construction and maintenance; (3) measurement and regulation; and (4) utility service.

Q. How does UGI Gas staff its operations?

A. UGI Gas relies upon a mix of employees and contractor resources for its capital, operations, and maintenance programs in order to accomplish many of its initiatives, including gas main and service replacement and installation, mechanical tee remediation, mercury regulator removal, roadway and landscape restoration, leak repairs, meter reading, and general system operation and maintenance. Further, UGI Gas's parent company, UGI Corp., provides management, administrative and support services (*e.g.*, executive management, human resources, legal, finance, accounting, procurement, treasury, IT, and corporate governance).

III. <u>COVID-19 OPERATIONAL IMPACTS AND UGI GAS'S RESPONSE</u>

Q. Please describe the operational impacts of the COVID-19 Pandemic on UGI Gas's operations and the Company's response to those challenges.

A. The Company's experience responding to the COVID-19 Pandemic, and specifically the programs and policies it adopted to assist customers, is detailed in the testimony of

Christopher R. Brown (UGI Gas Statement No. 1). From an operational perspective, COVID-19 impacted the Company's approach to project planning, including the availability of personnel to complete fieldwork. The economic impacts resulting from COVD-19 increased costs, presented challenges in securing necessary supplies, and created issues in the labor market that UGI Gas must respond to in order to maintain its workforce.

Specifically, UGI Gas stopped all non-emergency work that required personnel to be outside their homes for a six-week period beginning in mid-March 2020 and ending on May 4, 2020. The Company then began a ramp up process to restart its construction program, focusing on work that did not involve customer contact. During this ramp up period, the Company initiated Measurement and Regulation ("M&R") station work, as well as direct bury main replacements. By June 2020, and in reliance on the Governor's return to work plan, UGI Gas began to conduct planned customer contact work in areas that had progressed to and maintained a "yellow status" for at least a two-week period. This allowed the Company to undertake certain main insert projects, which resulted in planned customer outages that required relights. UGI Gas also began conducting service renewals during his period. By mid-July 2020, the Company resumed high customer contact activities throughout the service territory.

Q. How has COVID-19 impacted the availability of personnel?

A. Throughout the Pandemic, COVID-19 significantly impacted the availability of personnel and caused project delays. UGI Gas also experienced employee and contractor absences due to illness or quarantine. The result of active COVID-19 cases and contact tracing made staffing challenges a regular factor in the Company's efforts to cover normal operational needs and keep construction projects moving. While COVID-19 impacts persist today, the Company is anticipating that such impacts will be minimal to ongoing operations on a going forward basis.

Another significant and lasting impact resulted from the temporary curtailment in hiring for the Capital Project Management and Capital Construction teams.[1] These new teams were designed to improve UGI Gas's ability to undertake replacement and betterment projects on a more efficient and expeditious basis, which was validated by an independent third-party study. The director roles for the new teams were hired just before the Pandemic began. However, UGI Gas temporarily halted its efforts to staff those teams when the Pandemic started. While the Company began the process of planning for and filling those roles in April 2020, securing candidates was challenging, due to the extremely competitive construction market. In 2021, candidates with flexible skills – particularly those in project management – were in high demand across many industries, including public utilities. Therefore, it has taken longer than initially anticipated to staff the new teams. While staffing challenges persist, the Company continues to make progress on this front, including the expanded use of outside support to meet its needs.

[1] From mid-March 2020 through the end of April 2020, the Company temporarily initiated a new employee hiring freeze until the impacts of COVID-19 on the Company's operations for the remainder of 2020 were clear. This temporary hiring freeze prevented the Company from reaching the headcount level projected by the end of the FY2021.

Q. Has UGI Gas experienced any other COVID-19 impacts that altered its normal project planning process?

A. Yes. The Company experienced delays in obtaining permits and state and local approvals that are needed prior to construction. Some local government offices remained closed after UGI Gas restarted its construction programs. Further, as a result of the need to avoid projects where the Company would be in close proximity to customers, Engineering and Operations modified their planned projects, which also created delays. For instance, some projects that were originally designed (and in some cases permitted) as insert main projects were redesigned as direct bury main replacement projects, which delayed service renewals and tie-overs. Although these actions allowed prioritized work to occur, they still impacted the pace of project completions. These Pandemic-related permit challenges have largely been minimized or eliminated in recent months.

In addition, as work resumed that involved customer contact, the Company addressed a backlog of service renewals, meter relocations, and service tie-overs (associated with work completed during the period that did not involve customer contact). There was also a modest delay of regulatory compliance work that was addressed upon restart of customer contact work streams. The Company addressed this backlog and is now maintaining a pace of ongoing projects commensurate with the Company's pre-COVID-19 work. Finally, the Company experienced and continues to experience supply chain challenges. For example, procurement lead times are much longer for many of the components required for natural gas system maintenance and construction, including pipe, tap fittings, valves, regulator station heaters, and regulator station components. Many of these supply procurement delays surfaced while projects were underway, delaying plant in service timing, extending project spend into additional fiscal periods, and adding resource demobilization and remobilization challenges. While supply chain issues continue to linger in part, the Company has adjusted its procurement activities to help minimize associated impacts.

Q. What actions has UGI Gas taken to reduce its vulnerability to prospective Pandemic-related impacts?

A. The Company has undertaken a number of steps based on its recent experiences responding to the rapidly changing operational landscape created by COVID-19. One important initiative was to diversify its supplier and contractor lists. UGI Gas has actively sought out new parties and new contractors to expand its bidder list for future projects. Doing so will improve the Company's resiliency by providing it with a wider pool of resources. Pandemic-mitigating employee policies, field procedure changes, and expanded inventories of pandemic-related personal protective equipment have positioned UGI Gas to continue typical operations and construction activities through anticipated public health challenges associated with the ongoing Pandemic.

IV. SYSTEM RELIABILITY AND SAFETY

Q. Please describe the physical composition of UGI Gas's distribution system.

A. Due to its long-term operation, the Company's distribution system includes a mixture of pipeline materials indicative of the industry's technological advancement over time. Cast iron mains can be found in the oldest parts of the system. The industry then transitioned to bare steel and wrought iron piping, which were prevalent until the 1960s. The first generation of plastic piping was introduced in the early 1970s. Materials installed since the 1970s include polyethylene (“PE”) and coated steel piping. Overall, approximately ninety percent (90%) of UGI Gas’s distribution mains consist of contemporary materials, which UGI Gas defines as cathodically-protected steel and plastic. UGI Gas’s natural gas distribution system has the highest percentage of contemporary mains among major natural gas distribution companies in Pennsylvania.

Q. Please discuss the Company’s action to improve and enhance its distribution system.

A. UGI Gas has been identifying and repairing, improving, or replacing its distribution infrastructure on an accelerated basis through Commission-approved Long Term Infrastructure Improvement Plans (“LTIIP”). The Company’s Initial LTIIP[2] and Second LTIIP[3] have resulted in UGI Gas successfully removing more than 463 miles of main over the seven (7) year period from 2014 to 2020, including sixty-six percent (66%) of its total cast iron mains and twenty-two percent (22%) of its total bare steel/wrought iron mains. As of December 31, 2021, the Company has removed an additional seventy-six (76) miles of main. Accordingly, UGI Gas has removed a total of seventy-two percent (72%) of its cast iron mains and twenty-six percent (26%) of its total bare steel/wrought iron mains from the system.

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[2] On December 12, 2013, each of UGI Gas’s three predecessor natural gas distribution companies filed Petitions, and received Commission approval, for LTIIPs at Docket Nos. P-2013-2398833, P-2013-2397056, and P-2013-2398835 (collectively referred to as the “Initial LTIIP”). In the Initial LTIIP, the Company identified its plan to replace all of its cast iron main over the 13-year period ending in February 2027 and all of its bare steel and wrought iron main over the 28-year period ending September 2041. The Initial LTIIP period ended on December 31, 2019.

[3] *See Petition of UGI Utilities, Inc. – Gas Division for Approval of its Second Long Term Infrastructure Improvement Plan*, Docket No. P-2019-3012337 (Petition filed on August 21, 2019) (the “Second LTIIP”). The Second LTIIP builds off of the significant acceleration in the rate of infrastructure repairs, improvements and replacements (including the accelerated replacement of cast iron and bare steel pipe) that was achieved by the Initial LTIIP and reflects even further acceleration.

UGI Gas will continue to invest in strengthening and modernizing its distribution facilities serving customers throughout the Company's service territory. This includes the replacement of another 210 total miles of cast iron, bare steel, and wrought iron main during the remaining years of the Second LTIIP. In addition to main replacements in the Second LTIIP, the Company has pursued other infrastructure initiatives through the Second LTIIP, including replacing service lines, meter sets, valves, farm taps, as well as addressing safety concerns relating to measurement and regulation facilities (e.g., making improvements to over-pressure protection equipment) and mechanical tees. These initiatives will make UGI Gas's system safer, more reliable, and easier to operate. Continuing UGI Gas's infrastructure replacement program will allow the Company to provide safe and reliable service both now and into the future.

Q. How does UGI Gas prioritize its pipeline replacement projects?

A. In 2019, UGI Gas began using the Data-Driven Risk Model ("DDRM"). The DDRM is a quantitative model incorporating leak repair data, incident data, and asset population data to calculate a risk index score for facility groupings referred to as Asset Threat Groups ("ATGs"). The Subject Matter Expert ("SME") driven Risk Model is still utilized to supplement risk evaluation to the DDRM and validates DDRM results by incorporating SME input. Optimain also continues to be utilized as a tool to evaluate risk on an individualized segment level and validates DDRM outputs for cast iron and steel mains.

The DDRM provides a quantitative basis for evaluating risk and creates a more stable foundation for comparing year-over-year changes, because of the consistent quantitative underpinning it utilizes. This quantitative underpinning largely resolves the effect of bias toward more recent events (often expressed by qualitative SME models, which tend to weight more heavily recent issues and concerns). Finally, the use of the DDRM helps UGI Gas better evaluate other effective approaches for addressing risk, including effective operations and maintenance programs, additional leak survey activities and damage prevention measures.

Q. **What are the Company's current goals for main replacement?**

A. UGI Gas is on track to replace all of its cast iron main no later than February 2027. Further, the Company plans to complete its bare steel and wrought iron main replacement no later than September 2041. Given the Company's accelerated pace of bare steel replacement reflected in the Second LTIIP, and continued into the future with necessary regulatory approvals, the Company currently is on pace to replace all bare steel mains a few years early, or by 2038.[4] Specifically, in order to achieve these objectives, the Company's Second LTIIP established the objective of replacing sixty-eight (68) miles of main in calendar year 2021, and seventy (70) miles of main in calendar years 2022 through 2024.

Q. Did UGI Gas achieve its mileage objective in 2021?

A. Yes, the Company achieved and exceeded its mileage objective, by replacing or retiring over seventy-six (76) miles of main in 2021.

[4] For any given intermediate period, the sequence of projects and the amount of specific facilities to be addressed may be adjusted in response to changing conditions. A variety of factors intrinsic to the natural gas distribution business may cause these changes to occur. These factors include, but are not limited to, state and municipal relocation projects, other private construction projects, system upgrades due to pressure requirements, regulatory changes, and legislative changes.

Q. What is UGI Gas's projection of its replacement and betterment plant in service for the future test year ("FTY") and the fully projected future test year ("FPFTY")?

A. For Fiscal Year ("FY") 2022, the replacement and betterment budget reflects $281.4 million plant in service. FY 2023 plant placed in service for replacement and betterment is budgeted to be $305.8 million. For more detail on the Company's budgeting process, please refer to the direct testimony of Vicky A. Schappell (UGI Gas Statement No. 5).

Q. What is the Company's basis for showing a further increase in plant placed in service in the FTY and FPFTY?

A. Foremost, the Company's annual plant additions over the period 2017-2021 have increased nearly $85 million over the time period, from $296 million in 2017 to $381 million in 2021. The Company anticipates that the cost of its replacement and betterment work will continue to increase through the FPFTY due to a number of different elements. First, the Company is further accelerating the number of miles it will accomplish in the FTY and FPFTY. In addition, these miles of main include large portions of the remaining cast iron main replacement projects, which must be completed by 2027, and are comprised of projects featuring increased complexity, challenging locations, and larger diameter pipes. For these reasons, UGI Gas's budget for the FTY and the FPFTY reflects increased plant additions beyond that amount that the Company had accomplished during the HTY.

Q. What other system reliability improvements has the Company performed recently?

A. In addition to pipeline replacement, the Company's Second LTIIP includes several projects related to natural gas system over pressure protection ("OPP"). Following recent overpressurization guidance issued by the National Transportation Safety Board ("NTSB") in 2019, UGI Gas evaluated the OPP utilized on its low-pressure systems. A total of seventy-three (73) regulator stations serving over 80,000 customers required supplemental OPP to comply with the NTSB's recommendations on OPP. UGI Gas implemented a plan to address supplemental OPP at all seventy-three (73) stations by the end of FY2023. As of September 30, 2021, forty-three (43) of the seventy-three (73) stations have been addressed through the installation of supplemental OPP, station abandonment, or station replacement. These projects were prioritized on a risk reduction basis seeking to maximize the customers served by NTSB-compliant systems meeting the NTSB recommendations. In this regard, over 71,000 of the 80,000 customers within the program are served by NTSB-recommended regulator stations as of September 30, 2021.

Concurrently, UGI Gas also implemented a plan to add remote pressure monitoring capabilities to its low-pressure systems. These capabilities include real-time alarm notifications to allow expedited system pressure correction and adjustment. As of September 30, 2021, remote pressure monitoring was deployed extensively with nearly 95% of all customers served by low-pressure systems having remote pressure monitoring capabilities. 100% customer coverage is planned in FY2022 on UGI Gas's low-pressure systems.

V. LEAK REDUCTIONS AND EMERGENCY RESPONSE

Q. Please discuss UGI Gas's efforts to reduce system leaks.

A. UGI Gas monitors safety and reliability indicators for its natural gas distribution system over time to evaluate corrosion and leak resolution performance, track emergency response, and pursue damage prevention – all of which will drive improvements in employee and public safety. As a part of its DIMP,[5] UGI Gas regularly re-assesses system risks and leak trends to determine if additional or accelerated actions are required to further reduce system leaks.

Leak surveys are an important tool for discovering, monitoring, and remediating leaks. To enhance its leak identification capabilities, UGI Gas initiated a "Mobile Guard" pilot program in June 2021. Pursuant to the pilot, the Company is testing the use of mobile gas leak detection equipment. The leak detection equipment is attached to a Company vehicle and can detect, map, and quantify methane emissions while driving up to 55 miles per hour. The equipment is being used to discover leaks on mains and adjacent service lines. This technology is a more efficient method that may be used to identify methane and ethane emission sources over a greater number of miles than traditional survey methods.

Additionally, the main replacement and modernization work identified by UGI Gas will provide customers with significant improvements in safety and reliability (*e.g.*, reduced leaks). The Company's replacement plans have been identified and prioritized on a risk basis in accordance with UGI Gas's DIMP and TIMP plans.[6] Risk-based prioritization helps ensure that the projects that deliver the most significant risk reductions are addressed first. As the investment plan progresses, customer benefits will manifest over time in terms of reduced leakage rates, fewer main breaks, and fewer unplanned customer interruptions. Furthermore, UGI Gas expects that the amount of lost and unaccounted for gas due to system leakage and measurement inaccuracy will be reduced as leaks are eliminated and meters are replaced.

[5] 49 C.F.R. § 192.1007.

[6] 49 C.F.R. §§ 195.450 and 195.452.

Q. How does UGI Gas classify leaks?

A. UGI Gas uses a standardized leak classification system consistent with general industry protocols. Specifically, underground leaks are classified as 'A,' 'B,' and 'C.' Class 'C' leaks are deemed hazardous and repaired immediately. Class 'B' leaks may become hazardous if otherwise not repaired, and they are scheduled for repairs within twelve (12) months and not to exceed fifteen (15) months. Class 'A' leaks are deemed non-hazardous and are monitored for changes in severity.

Q. How have UGI Gas's system leaks improved since 2016?

A. UGI Gas has seen a significant reduction in the number of leaks found on its system. This is directly attributable to its prioritization and aggressive replacement of leak-prone mains, services, and other assets. As Table 1 below demonstrates, since 2016, C Leak repairs have decreased by 27.2%, B Leak inventories have decreased by 52.5%, and A Leak inventories have decreased by 21.3%.

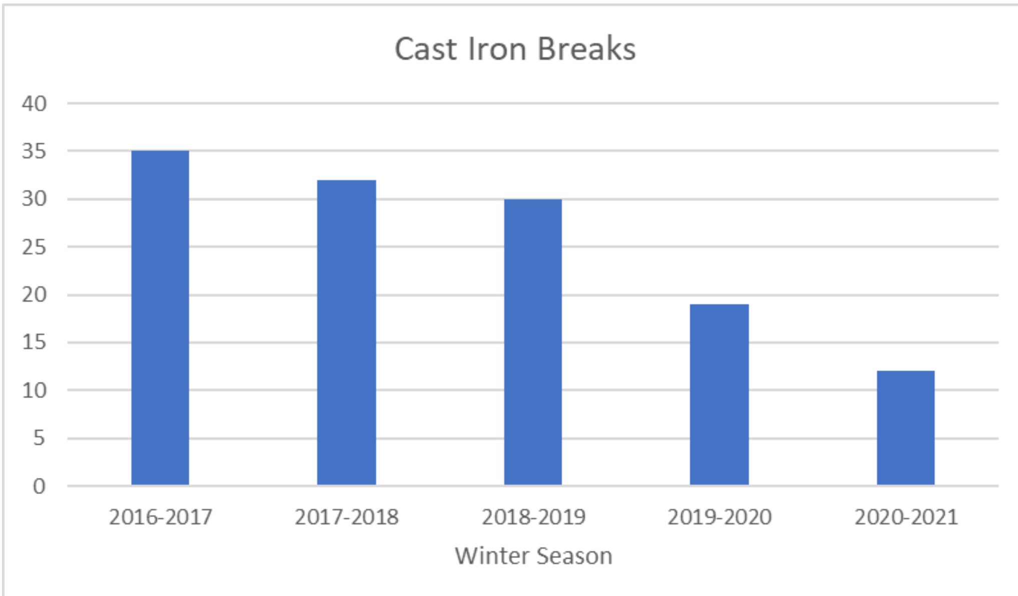
Table 1. Leak Inventories & Repairs

	Calendar Year 2016	**Calendar Year 2021**	**Percent Change**
C Leak Repairs	1,496	1,089	27.2% decrease
B Leak Inventory	556	264	52.5% decrease
A Leak Inventory	4,930	3,882	21.3% decrease

Figure 1 below shows the reduction in the number of cast iron breaks each winter season since the 2016-2017 season. There has been an overall sixty-six percent (66%)

reduction in break frequency since the 2016-2017 season. The reduction helps demonstrate effectiveness of cast iron replacement activities.

Figure 1. Cast Iron Main Breaks (2016-2021)



Q. How is UGI Gas's performance in the area of emergency response rate?

A. UGI Gas performs very well in the timely response to emergency notifications/calls. For the Fiscal Year ended September 30, 2021, 98.4% of the time, a first responder arrived on the premises within forty-five (45) minutes of receipt of an emergency call. UGI Gas utilizes a combination of shift coverage and on-call schedules to leverage internal field and supervisory resources to provide emergency response coverage 24-hours per day, 365 days per year. I also note that UGI Gas sets performance goals on a forty-five (45) minute response, which is more stringent than the acceptable odor response time as defined by the

Commission's Safety Division.[7] Moreover, for FY2021, 99.8% of the time a UGI Gas first responder arrived onsite within one hour of the emergency call. This compares favorably to the industry average.

VI. EMPLOYEE ADDITIONS

Q. Does the Company's budget include additional employees for operational purposes in this case?

A. Yes, the Company's budget reflects an increase of twenty-three (23) operations employees. Fifteen (15) of these positions will be added in 2022 and eight (8) will be added in 2023. In addition to these budgeted positions, the Company is preparing to add twenty (20) more employees in 2023 to address staffing needs analysis updates that were completed after the budget process.

Q. What is the driver for these additional staffing needs?

A. The Company faces two significant employee challenges: forecasted retirements and attrition of newer employees. These challenges require an aggressive and multifaceted approach so the Company can continue to accomplish fieldwork critical to safety and reliability, including meeting planned replacement goals pursuant to the Company's LTIIP.

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[7] The Commission's Bureau of Audits issued a Management and Operations Audit Report of the Company in October 2019 (at Docket Nos. D-2018-3002234, D-2018-3002235 and D-2018-3002236), which stated:

> The PUC Gas Safety Division defines acceptable emergency dispatch and response times as 15 minutes and 60 minutes, respectively. However, UGI has established a more stringent 45-minute emergency response key performance indicator of 97.8%. (Audit Report, p. 41).

Q. Please identify the types of employees that are considered operational employees.

A. Operational employees encompass several roles including gas mechanics/field technicians, equipment operators, laborers, meter readers, and contractor inspectors, as well as clerical, supervisory, and leadership staff to support these roles. The majority of UGI's operational employees are union employees who directly perform, or inspect contractors who perform, operation, maintenance, construction, or replacement activities. Most operational employees also perform emergency response activities both during and after business hours. Typically, union employees are hired into apprentice programs as specified in the applicable collective bargaining agreement. Though UGI Gas provides formal and on the job training to new hires, it takes a number of years before these employees can progress to general gas mechanic functions, including emergency response, facility locating and markouts, and leak repair. Employees may then progress to more advanced functions, including contractor inspection or supervisory roles.

Q. Please describe the challenge stemming from forecasted retirements.

A. UGI Gas actively monitors and plans for the anticipated retirement of many experienced utility workers. Table 2 shows the anticipated number of operational employees that are or will be eligible for retirement over the five-year period from FY2022 through FY2026. Of the twenty-eight (28) employees listed for FY2022, twenty-one (21) employees reached retirement age prior to September 30, 2021, but have not retired as of the beginning of FY2022.

Table 2. UGI Gas Operations Employees Aged 65 or Older Per Year

	FY22	FY23	FY24	FY25	FY26
Retirement Count	28	10	12	17	24
Average Tenure (years)	38.0	33.4	36.8	28.9	28.6

On a collective basis, these employees represent decades of operational experience. The Company seeks to increase its total number of operational employees in order to provide an opportunity for both formal training and the on-the-job learning, which normally takes place over time and is necessary to ensure the continuity of the workforce. This is particularly critical for employees who can conduct quality and safety inspections. It takes five (5) years on the job for an employee to become fully qualified to perform gas operations tasks, including contractor inspection work, general tapping and stopping, plastic pipe fusing, regulator station maintenance and troubleshooting, emergency first response on call, and internal crew leadership.

Q. What additional needs are related to employee resource requirements in support of the Company's replacement activities?

A. UGI Gas relies on contractor resources to perform most of its replacement and betterment activity. This limits the overall staffing and equipment UGI Gas is required to maintain, while providing cost effective resource scalability and geographical flexibility not easily achieved with internal resources. UGI Gas utilizes internal resources to coordinate and inspect contractor work performance to ensure quality construction, confirm procedural compliance, and validate contractor payments. These experienced employees are critical to UGI Gas's continued ability to complete projects in a safe, reliable, and fiscally responsible manner. Expanding the number of employees who can conduct capital-related activities will ensure that as the Company's capital activities accelerate, UGI Gas will be able to safely complete its additional infrastructure replacement projects on time in order to achieve its goals of removing all cast iron main from its system by 2027 and all bare steel and wrought iron main by 2041.

Q. What are the challenges posed by the attrition of newer employees?

A. UGI Gas has seen significant turnover of apprentice level employees who remain at the Company for less than five (5) years. Over the last five (5) years, UGI Gas has seen the voluntary departure of one hundred (100) employees with five (5) years of experience or less with the Company. During that same time period, only twenty-seven (27) employees with more than five (5) years of experience (excluding retirements) voluntarily left the Company. While the Company has consistently replaced these apprentice level employees, the ongoing loss of apprentice level employees has created a growing gap of experience between the number of apprentice employees and those that have five (5) or more years of experience.

As I previously described, the loss of experienced employees becomes an impediment when UGI Gas cannot transition enough employees from the apprentice level to the point where they can conduct more complex and technically challenging work. The first step to overcome this attrition is to bring in a greater number of new hires. This is particularly true in light of current market conditions, where UGI Gas also faces competition from many other entities located within its service territory. As a result, UGI Gas must be more aggressive in bringing in more candidates, in order to keep its workforce fully staffed in support of replacement activities in particular.

Q. Is the Company taking any other steps to address the attrition of apprentice level employees?

A. UGI Gas is taking a two-step approach: First, it is seeking to increase the number of apprentice level employees that come in the door. Even if the extremely competitive construction market continues into the future, the Company will continue to work to retain enough employees to ensure a sufficient number of experienced employees capable of undertaking complex projects. However, the Company invests a significant amount of time and resources when hiring, onboarding, and training new employees. Losing relatively new employees puts a strain on many Company resources and results in increased costs. Therefore, a second step is needed to retain more employees. As described in the testimony of Mr. Brown (UGI Gas Statement No. 1), UGI Gas plans to reduce the overall attrition by using a more comprehensive market-based approach to establishing wages and salaries. This will give recent hires an incentive to stay with the Company and move to more senior or supervisory positions. The Company believes these steps can address the combined threat posed by the high rates of both retirement and attrition, while continuing its accelerated capital replacement work.

VII. SAFETY INITIATIVES

Q. What programs does UGI Gas have in place regarding employee, customer, and system safety?

A. Safety performance is a core value to UGI Gas. The Company's success depends on its employees' commitment and dedication to safety. Therefore, UGI Gas maintains a culture that drives employees to perform their day to day responsibilities with a high degree of safety. Moreover, UGI Gas is advancing several initiatives to further develop its safety culture and drive sustainable improvements in safety performance. One such program is the UGI "Making a Difference by Living Our Values" Incentive Program. It rewards employees who demonstrate positive safety behaviors, including but not limited to, leading safety meetings, reporting safety issues, or participating in safety education. Employees can nominate individuals who demonstrate/exhibit safety values, impact/promote safe workplace practices, or significantly impact or improve safety in the Company's operations. Winners are recognized by receiving points, which are redeemable for merchandise, gift cards, etc.

Additionally, the Company is building a new Safety and Health Management System ("SHMS"), which will assist the Company in recognizing and fixing workplace hazards before they cause injury or illness. The program focuses on: Management Leadership, Worker Participation, Hazard Identification & Assessment, Hazard Prevention & Control, Education & Training, and Program Evaluation & Improvement.

Finally, UGI Gas's SHMS incorporates the American Petroleum Institute ("API") Recommended Practice 1173 ("API RP 1173"), which establishes a pipeline safety management systems ("PSMS") framework for corporations that operate hazardous liquids and gas pipelines under the U.S. Department of Transportation's jurisdiction. It provides a framework to reveal and manage risk, promotes a learning environment, and continuously improves pipeline safety and integrity. This continuous improvement effort and framework reduces hazards and prevents incidents.

Q. What other ongoing safety programs does the Company have?

A. Other ongoing safety measures and tools include Smith System driver training; the twenty-four- (24-) hour Triage Nurse Hotline; a fleet management tool that generates a driver safety score utilizing GPS technology; and selective driver monitoring technology. The Company has also adopted multiple programs to enhance its safety protocols. Programs include the "Near Miss/Good Catch" program, which seeks to proactively prevent safety incidents by learning from issues that had the potential for, but did not result in, damage or harm. In addition, the Company uses EcoOnline safety incident software, which facilitates incident management and data collection for various types of incidents and also tracks those incidents through the investigation process. The Company also utilizes ISNetworld vendor safety software to qualify contractors and monitor their performance trends. ISNetworld collects safety information from these contractors and compares them against UGI Gas's established safety standards to make sure they are qualified to perform work for the Company. ISNetworld conducts ongoing monitoring of the contractor's safety information and alerts UGI Gas if a contractor falls below the Company's minimum safety standards – either in UGI Gas's service territory or anywhere else in the country. This helps ensure that UGI Gas's contractors provide safe and reliable service to the Company's community and customers.

Q. What training initiatives is the Company undertaking?

A. The Company recently opened its centralized training facility (the "Training Center"). The Training Center is being used for all new hire and employee progression field training. Initial training for employees acquiring new skills and operator qualifications occur at the

Training Center. It is also being used for ongoing training and operator re-qualification for employees and contractors.

The Company's technical training team has nearly completed aligning UGI Gas's operator qualification program with the American Society of Mechanical Engineers ("ASME") B31Q Standard. Conversion to this standard is expected to be completed in FY2022 and will result in training improvements, including Gas Technical Institute training modules that will be customized to meet UGI Gas's processes and procedures. This work was started in FY2021 and is expected to take several years to complete.

VIII. ENVIRONMENTAL

A. ENVIRONMENTAL REMEDIATION PROGRAM

Q. Please discuss environmental management at UGI Gas.

A. The environmental group at UGI Gas is focused on three (3) main activities: (1) the investigation and remediation of environmental impacts related to historical operations; (2) environmental compliance activities, such as permitting and operational improvements; and (3) sustainability and methane reduction activities.

Q. Please describe the Company's investigation and remediation of environmental impacts related to historical operations.

A. From the late 1800s through the mid-1900s, UGI Gas and its predecessors owned and operated a number of manufactured gas plants ("MGPs") that, prior to the general availability of natural gas, generated gas from other fuel stocks for residential, commercial, and industrial customer use. In Pennsylvania, this process generally used coal as a fuel stock. Some byproducts of this manufacturing process, including coal tars and other residues of the manufactured gas process, are today considered hazardous substances under state and federal environmental laws.

Historically, UGI Gas operated its environmental remediation programs under three (3) consent orders and agreements ("COA") with the Pennsylvania Department of Environmental Protection ("PADEP"). UGI Gas's former utility companies, UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas, Inc. ("UGI CPG"), were each parties to separate COAs with PADEP, and a UGI Gas COA was executed in 2016. Following UGI CPG and UGI PNG's merger into UGI Gas, on October 1, 2020, the UGI COA was amended to incorporate the UGI CPG and UGI PNG COAs into a single UGI Gas COA that will terminate on October 1, 2031. This COA obligates the Company to either meet an annual minimum environmental spend commitment or complete a sufficient number of environmental activities to achieve a minimum annual point total. The minimum annual spend for the UGI Gas COA is $5.35 million.

Q. What types of costs does UGI Gas incur with respect to addressing MGP site conditions?

A. UGI Gas incurs costs attributed to site investigations, remediation, and site restoration as well as related PADEP oversight costs. Costs may also be incurred to obtain an environmental covenant at the site to prevent certain uses of the site, and costs associated with transferring the site to a third party (such as with a dedication for public use) once the site has been restored. Costs may also be incurred to purchase a property to secure access to investigate and remediate. Additionally, expert and legal costs are sometimes incurred in interactions with insurance carriers or other potentially responsible parties to ensure that UGI Gas's customers are only paying their equitable share of investigation and remediation costs. Costs may be incurred to implement PADEP workplans if the Company faces opposition to the investigation or remediation of the site. Costs may also be incurred to recover compensation under historical insurance policies to offset the costs that would otherwise be recovered from customers.

Q. What is UGI Gas's projected spending on the MGP program?

A. UGI Gas holds the COA annual minimum spend of $5.35 million as the target projected spend for each year to meet the COA objectives, if minimum annual points cannot be achieved. UGI Gas's average aggregate annual spending over the past three fiscal years is $5.171 million, as shown below in Table 3.

Table 3. Environmental Spent per Fiscal Year

Fiscal Year	**Total**
2019	$4,810,983
2020	$4,243,130
2021	$6,459,545
Total	$15,513,658
Average	$5,171,219

The average amount is used in the calculation of the environmental adjustment shown in UGI Gas Exhibit A, Schedule D-8, as discussed in the direct testimony of Ms. Tracy A. Hazenstab (UGI Gas Statement. No. 2).

Q. Why does environmental spend vary from the minimum environmental spend set by the COA?

A. While the Company uses the environmental minimum spend as a benchmark for budgeting, actual costs may exceed the minimum in certain years due to PADEP requirements, changing environmental standards, and site-specific issues such as sensitive habitat and concentration of contaminants. The 2020 spend was also influenced by the Pandemic, which constrained field activities for a considerable portion of the year. To catch-up for the 2020 target spend differential, additional funds beyond the target of $5.35 million were spent in 2021. In years when the Company is unable to make its minimum spend commitments, it can avail itself of an alternative compliance pathway under each COA that permits the Company to use banked points for remedial work completed in past years.

Q. What is UGI Gas's goal for restoration of the MGP sites?

A. UGI Gas strives to restore each site for beneficial reuse that becomes an asset to the Company or the community. Because these MGP sites are located within the Company's existing service territory, restoration of the sites for beneficial reuse, whether in the form of urban redevelopment or the creation of a new public space, directly benefits UGI Gas's customers.

B. EMISSIONS REDUCTIONS PROGRAMS

Q. How does UGI Gas quantify the environmental impact of its operations?

A. In addition to the ESG program areas discussed in Mr. Brown's testimony (*e.g.*, oil to gas conversion, EE&C, etc.) (UGI Gas Statement No. 1) that reduce emissions, UGI Gas has been a partner in the United States Environmental Protection Agency's ("EPA") voluntary

Natural Gas STAR program since its inception. Natural Gas STAR provides a framework to encourage partner companies to implement methane emissions reducing technologies and practices and document their voluntary emission reduction activities. On March 30, 2016, UGI Gas joined with thirty-two (32) other natural gas utilities to launch the EPA's Natural Gas STAR Methane Challenge Program. As a founding member of the STAR Methane Challenge, UGI Gas has committed to making and tracking emissions reductions. Participation in this voluntary program includes a commitment to replace infrastructure to achieve a reduction in fugitive methane emissions. UGI Gas reduced fugitive methane emissions by 5.6% in 2019-2020 (at the time of this filing, the EPA Methane Challenge STAR Program report for 2020-2021 has not yet been published).

UGI Gas continues to add Compressed Natural Gas ("CNG") vehicles to its fleet. Currently, the fleet is made up of twelve percent (12%) CNG-powered vehicles, with plans to increase the number to twenty percent (20%) by the end of 2023. Three (3) of the Company's operations locations have CNG filling stations (Archbald, Wilkes-Barre, and Bethlehem) with plans to add another station near its Middletown office. Utilizing nearby commercial CNG fueling stations makes it feasible to convert fleets to CNG in smaller operations centers.

Q. Does that conclude your testimony?

A. Yes, it does.

UGI GAS

EXHIBIT TJA-1

TIMOTHY J. ANGSTADT

UGI UTILITIES, INC.
VICE PRESIDENT – OPERATIONS

Summary

Engineering and Operations executive with over 22 years of broad experience in natural gas transmission and distribution activities, including operations and maintenance, engineering, regulatory compliance, capital budgeting and construction, project management, technology implementation, and business process transformation. As Vice President – Operations:

- Leads a team of over 850 individuals including management, engineering, clerical, and field technicians to operate and maintain over 12,000 miles of natural gas transmission and distribution pipelines and related assets, serving over 672,000 customers in Pennsylvania and Maryland.
- Champion/executive sponsor of UGI's Safety Culture Initiative; member of executive steering team responsible for the ongoing improvement of safety culture, performance, and leadership throughout the company.

Prior Positions with UGI Utilities, Inc.

Vice President – Operations (Denver, Pa.)	February 2019 - Present
Program Director – UNITE (UGI's Next Info. Technology Enterprise) (Reading, Pa.)	February 2016 – February 2019
Director – Operations, South Region (Reading, Pa.)	June 2012 – February 2016
Operations Manager – West Region (Harrisburg/Middletown, Pa.)	July 2008 – June 2012
Manager – Operational Support (Reading, Pa.)	December 2007 – July 2008
Manager – UGI/Penn Natural Gas Integration (Wilkes-Barre/Reading, Pa.)	November 2006 – December 2007
Engineer – Customer Service and Performance Systems (Reading, Pa.)	June 2005 – November 2006
Operations/Construction and Maintenance Superintendent (Reading, Pa.)	September 2003 – June 2005
Engineer II – Gas Utility Headquarters (Reading, Pa.)	January 2003 – September 2003
Engineer I/II – Reading Area (Reading, Pa.)	January 2000-January 2003
Engineering Assistant – Reading Area (Reading, Pa.)	June 1999 – August 1999

Education

MiF, The Pennsylvania State University, Malvern, Pa.
MBA, The Pennsylvania State University, Malvern, Pa.
BS, Mechanical Engineering, The Pennsylvania State University, State College, Pa.

Prior testimony provided to the Pennsylvania Public Utility Commission:

Docket No. R-2019-3015162 UGI Utilities, Inc. Gas Division - Base Rate Case Proceeding

UGI GAS STATEMENT NO. 10

CONSTANCE E. HEPPENSTALL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 10

Direct Testimony of
Constance E. Heppenstall

Topics Addressed: **Cost of Service Allocation**

Date: January 28, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Constance E. Heppenstall. My business address is 1010 Adams Avenue, Audubon, Pennsylvania.

Q. By whom are you employed?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC.

Q. Please describe your position with Gannett Fleming Valuation and Rate Consultants, LLC., and briefly state your general duties and responsibilities.

A. My title is Senior Project Manager, Rate Studies. My duties and responsibilities include the preparation of accounting and financial data for revenue requirement and cash working capital claims, the allocation of cost of service to customer classifications, and the design of customer rates in support of public utility rate filings.

Q. Have you presented testimony in rate proceedings before a regulatory agency?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PA PUC" or the "Commission"), the Arizona Corporation Commission, the Kentucky Public Service Commission, the Virginia State Corporation Commission, the Missouri Public Service Commission, the Hawaii Public Utilities Commission, the West Virginia Public Service Commission, the Indiana Utility Regulatory Commission, the California Public Utilities Commission, the Public Utilities Commission of Ohio, and the New Jersey Board of Public Utilities concerning revenue requirements, cost of service allocation, and rate design. A list of cases in which I have testified is attached to my testimony.

Q. What involvement have you had in preparing past cost of service studies for UGI Gas?

A. Since 2006, I have assisted with the preparation of all of UGI Gas's allocated cost of service studies, except for the one utilized in the Company's 2020 Gas Base Rate Case at Docket No. R-2019-3015162.

Q. What is your educational background?

A. I have a Bachelor of Arts in Economics from the University of Virginia, Charlottesville, Virginia and a Master of Science in Industrial Administration from the Tepper School of Business at Carnegie Mellon University, Pittsburgh, Pennsylvania.

Q. Would you please describe your professional affiliations?

A. I am a member of the American Water Works Association, the National Association of Water Companies, and the Pennsylvania Municipal Authorities Association.

Q. Briefly describe your work experience.

A. I joined the Valuation and Rate Division of Gannett Fleming, Inc. in August 2006, as a Rate Analyst and was promoted to my current position in 2012. Prior to my employment at Gannett Fleming, Inc., I was a Vice President of PriMuni, LLP where I developed financial analyses to test proprietary software in order to ensure its pricing accuracy in accordance with securities industry's conventions. From 1987 to 2001, I was employed by Commonwealth Securities and Investments, Inc. as a public finance professional where I created and implemented financial models for public finance clients in order to create debt structures to meet clients' needs. From 1986 to 1987, I was a public finance associate with Mellon Capital Markets.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"). I will explain the cost of service allocation study, which is included with the filing as UGI Gas Exhibit D.

II. COST OF SERVICE ALLOCATION STUDY

Q. What is the purpose of the cost of service allocation study?

A. The purpose of the study is to allocate the total cost of service to the appropriate service classifications.

Q. What method of cost allocation was used in the studies?

A. I used the Average and Extra Demand Method (Average/Excess), which is described in UGI Gas Exhibit D and in the text, "Gas Rate Fundamentals," published by the American Gas Association's Rate Committee.

Q. Please describe UGI Gas Exhibit D.

A. UGI Gas Exhibit D titled, "Cost of Service Allocation Study as of September 30, 2023," is the cost of service allocation study prepared for UGI Gas in support of its claims in this proceeding. It sets forth the results of the study based on the projected costs and conditions for the fully projected future test year for the 12 months ending September

30, 2023 ("FPFTY"). The data in the exhibit include a description of the methods and procedures used in the study, the allocations of cost of service and measure of value, the factors on which the allocations were based, and an analysis of customer costs.

Q. Please outline the procedure that you followed in the first cost allocation study.

A. The detailed allocation of costs to cost functions and service classifications is presented in Schedule E of UGI Gas Exhibit D. Gas costs are excluded from the amounts in Schedule E in order to develop costs by function and classification related to the delivery of gas.

In the detailed allocation, the items of cost, which include operating expenses, depreciation expense, taxes, and income available for return, are identified in column 1 of Schedule E. The cost of each item, shown in column 3, is allocated to the appropriate service classifications: Residential (R and RT), Non-Residential (N and NT), Delivery Service (DS), Large Firm Delivery Service (LFD), Extended Large Firm Delivery Service (XD-Firm), and Interruptible Service (IS).

The allocation factor codes entered in column 2 enable one to determine the specific basis for the allocation of each item. The factor codes refer to the information presented in Schedule F of the exhibit.

Q. Please explain the allocation of some of the large cost items in the study.

A. Referring to some of the larger delivery cost items, the costs associated with natural gas production expenses were allocated based on purchased gas cost volumes for Rate R and Rate N customers, as shown in the development of Factor 1.

The costs related to distribution mains were first directly assigned to Rate XD-Firm and XD-I (a portion of IS-interruptible) customers based on an analysis of the mains and the proportion thereof serving each individual Rate XD customer. The methods and procedures used to determine the portion of mains directly assigned to Rate XD customers were provided by Company personnel. The remaining cost of mains was separated into small mains (2-inch and smaller) and large mains (over 2-inch). The allocation of costs related to these mains is based on Factor 4, which weights the factors related to average daily throughput volumes and from maximum day extra capacity demand.

Customers under Rate XD-Firm and XD-I were excluded from the allocation of small and large distribution mains since Rate XD customers were directly assigned the cost of mains serving them, as explained above. Interruptible volumes were removed from the extra capacity calculations as these volumes can be curtailed during periods of peak demand. In addition, certain Interruptible volumes that are 100% interruptible were excluded from Factor 4.

Q. How did you weight the average and excess portions for Allocation Factor 4?

A. The weighting of the factors was based on the system-wide load factor for firm service. This results in 39.9% allocated based on average daily usage and 60.1% on excess above average day usage. See Factor 3 for the calculation of the firm service load factor.

Q. Please discuss the allocation of costs related to Load Dispatching, Measuring and Regulation ("M&R") Station Equipment, and operational costs related to large mains.

A. The costs related to Load Dispatching and M&R Station Equipment are allocated based on Factor 4A. This factor is similar to the allocation in Factor 4, but it includes average daily throughput volumes related to XD Firm customers as these customers benefit from this equipment. Operational costs related to large mains are allocated based the allocation of rate base for large and directly assigned mains, Factor 17.

Q. Please explain the allocation of meters and service line costs.

A. Costs related to service lines in Account 380 were allocated to classes, based on an analysis of service line investment by size and Rate Class as presented in the response to Standard Data Request SDR-COS-6, as developed in Factor 6C. Costs related to meters in Accounts 381, 382, and 385 were allocated to the classes based on an analysis of meter investment by size and Rate Class as presented in response to Standard Data Request SDR-COS-7, as developed in Factor 6. The costs related to House Regulators are allocated to Rate R and N classes based the weighted number of regulators, or Factor 6A. Finally, the costs associated with Industrial Measuring and Regulating Equipment are allocated based on the costs of meters and measuring and regulating equipment for the Rate DS, LFD, XD-Firm, and Interruptible classes.

Q. Please explain the allocation of Distribution Operation and Maintenance Other Expenses.

A. These expenses were allocated based on Factors 10 and 11. These factors are based on costs previously allocated as described above.

Q. Please explain the allocation of uncollectible accounts and customer assistance expenses.

A**.** Uncollectible accounts associated with the gas cost portion are allocated consistent with the recovery of such costs through the Merchant Function Charge (Rider D) for Rates R and N. The remaining uncollectible account cost is recovered based on an analysis of write-offs, as shown in the development of Factor 19. Costs associated with customer assistance programs are allocated directly to the residential class.

Q. Please describe the allocation of customer accounting, customer service, sales costs, and the remaining cost of service elements.

A. Customer accounting and certain customer service costs were allocated to service classifications on the basis of the number of customers, using Factor 7. Costs related to customer assistance programs were directly allocated to the Rate R class. The Energy Efficiency and Conservation program costs were allocated based on the revenue from the EEC Rider. Sales expenses, except for costs related to Service Representatives, were allocated to the Rate R and N classes based on number of customers, Factor 8. The costs related to Service Representatives, who serve the larger customers, were allocated to the large customer classes of DS, LFG, XD-Firm, and Interruptible based on number of customers in these classes, Factor 7A. Administrative and general costs were allocated on the basis of the allocated direct operation and maintenance costs, excluding gas production expenses, using Factor 12. Labor related pension and benefits are allocated based on an operation and maintenance direct labor expense, as shown in Factor 13.

Annual depreciation accruals were allocated on the basis of the function of the facilities represented by the depreciation expense for each depreciable plant account. Similarly, certain taxes other than income taxes, income taxes, and income available for return were allocated on the basis of allocated rate base, including the original cost less accrued depreciation of utility plant in service and other rate base elements.

Q. **What are the results of the cost of service allocation study?**

A. The results of the cost of service allocation set forth in Schedule E are brought forward and summarized in Schedule D. The total cost of service by classification in Schedule D is then brought forward to Schedule A (without gas costs), columns 2 and 3, where these results are compared to the *pro forma* revenues under present rates (columns 4 and 5) and proposed rates (columns 6 and 7). The proposed change in revenue under proposed rates and the percent change are shown in columns 8 and 9 of Schedule A. Please refer to the direct testimony of Company witness Sherry A. Epler (UGI Gas Statement No. 8) for an explanation of the proposed rate design and revenue distribution.

Q. Did you prepare a schedule showing the rate of return by classification?

A. Yes. Schedule B sets forth the rate of return by classification under present rates, and Schedule C shows the rate of return by classification under proposed rates.

Q. Did you prepare an analysis of customer costs?

A. Yes. I prepared a fully allocated customer cost analysis and a direct customer cost analysis. Both analyses of customer costs are presented in Schedule G of UGI Gas Exhibit D.

Q. Please explain the analysis of customer costs as set forth in UGI Gas Exhibit D.

A. In UGI Gas Exhibit D, all costs are first allocated to either volumetric costs or customer costs, as shown in Schedule E. The customer costs are allocated to the classes based on an analysis of meter and service line costs and the number of customers. The customer costs were further allocated to the R, N, DS, LFD, XD, and Interruptible Service classifications in the same schedule. The factors that were the bases for the allocation to cost functions and the allocation of customer costs to classifications are presented in Schedule F. A summary of the customer costs and the development of the costs per customer per month are presented in Schedule G.

Q. Did you prepare an analysis of costs related to the demand charge for Rate LFD and Rate XD-Firm Service?

A. Yes. The analysis of costs related to the demand charges for Rate LFD and Rate XD-Firm Service is presented in Schedule H of UGI Gas Exhibit D.

Q. Please explain the analysis of the Rate LFD and Rate XD-Firm Service costs related to demand charges as set forth in UGI Gas Exhibit D.

A. The costs related to Rate LFD and Rate XD-Firm Service demand charges were determined by the allocation of certain fixed costs, depreciation, taxes and return to these classifications. The allocation was performed in Schedule E. A summary of the allocated costs and the development of the unit demand costs are presented in Schedule H.

Q. Does that conclude your direct testimony?

A. Yes, it does.

CONSTANCE E. HEPPENSTALL – LIST OF CASES TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
1.	2010	AZ CC	W-01303A-09-0343 and SW-01303A-09-0343	Arizona American Water Company	Rate Consolidation
2.	2010	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Revenue Requirements
3.	2012	PA PUC	R-2012-2311725	Hanover Borough	Cost of Service/Revenue Requirements
4.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Revenue Requirements
5.	2013	PA PUC	R-2013-2350509	City of DuBois – Bureau of Water	Revenue Requirements
6.	2013	PA PUC	R-2013-2390244	City of Bethlehem – Bureau of Water	Revenue Requirements
7.	2014	PA PUC	R-2014-2418872	City of Lancaster – Bureau of Water	Revenue Requirements
8.	2014	PA PUC	R-2014-2428304	Hanover Borough	Revenue and Revenue Requirements
9.	2015	KY PSC	Case No.2015-000143	Northern Kentucky Water District	Cost of Service
10.	2016	PA PUC	R-2016-2554150	City of DuBois – Bureau of Water	Cost of Service/Revenue Requirements
11.	2016	AZ CC	WS-01303A-16-0145	EPCOR Water Arizona, Inc.	Cost of Service/Rate Design
12.	2017	MO PSC	WR-2017-0285	Missouri-American Water Company	Cost of Service/Rate Design
13.	2017	MO PSC	SR-2017-0286	Missouri-American Water Company	Cost of Service/Rate Design
14.	2017	VA SCC	PUR-2017-00082	Aqua Virginia, Inc	Cost of Service
15.	2017	AZ CC	WS-01303A-17-0257	EPCOR Water Arizona, Inc	Cost of Service/Rate Design
16.	2017	HI PUC	2017-0446	Hana Water Systems, LLC – North	Cost of Service/Rate Design
17.	2017	HI PUC	2017-0447	Hana Water Systems, LLC – South	Cost of Service/Rate Design
18.	2018	PA PUC	2018-200208	SUEZ Water Pennsylvania	Revenue Requirements
19.	2018	KY PSC	2018-00208	Water Service Corp of KY	Cost of Service/Rate Design
20.	2018	WV PSC	18-0573-W-42t	West Virginia American Water Co.	Cost of Service
21.	2018	IN IRC	50208	Indiana American Water Company	Cost of Service/Demand Study
22.	2018	KY PSC	2018-00291	Northern Kentucky Water District	Cost of Service/Rate Design
23.	2018	KY PSC	2018-0358	Kentucky American Water	Cost of Service/Rate Design
24.	2019	PA PUC	2019-3006904	Newtown Artesian Water Co.	Revenue Reqmts./Rate Design
25.	2019	PA PUC	2019-3010955	City of Lancaster – Sewer Fund	Rev. Reqmts./Cost of Service/Rates
26.	2020	PA PUC	2020-3017206	Philadelphia Gas Works	Cost of Service
27.	2020	PA PUC	2020-3019369	Pennsylvania American Water Co.	Cost of Service/Rate Design
28.	2020	PA PUC	2020-3019371	Pennsylvania American Water Co.	Cost of Service/Rate Design
29.	2020	PA PUC	2020-3020256	City of Bethlehem	Rev. Reqmts./Cost of Service/Rates
30.	2020	CA PUC	A2101003	San Jose Water Company	Rate Design
31.	2020	VA SCC	PUR-2020-00106	Aqua Virginia, Inc.	Cost of Service
32.	2021	OH PUC	21-0595-WW-AIR	Aqua Ohio, Inc	Cost of Service
33.	2021	OH PUC	21-0596-ST-AIR	Aqua Ohio, Inc	Cost of Service
34.	2021	PA PUC	R-2021-3026116	Hanover Borough	Cost of Service
35.	2021	NJ BPU	WR21071007	Atlantic City Sewerage Co.	Rev. Reqmts./Cost of Service/Rates
36.	2021	PA PUC	R-2021-3027385	Aqua Pennsylvania	Cost of Service/Rate Design
37.	2021	PA PUC	R-2021-3027386	Aqua Pennsylvania	Cost of Service/Rate Design
38.	2021	PA PUC	R-2021-3026682	City of Lancaster – Bureau of Water	Cost of Service/Rate Design

UGI GAS STATEMENT NO. 11

JOHN D. TAYLOR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2021-3030218

UGI Utilities, Inc. – Gas Division

Statement No. 11

Direct Testimony

of

John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed: **Weather Normalization Rider**

Dated: January 28, 2022

TABLE OF CONTENTS

Direct Testimony of John D. Taylor

I. INTRODUCTION

Q. Please state your name, affiliation, and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium Economics" or "Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company").

Q. Please describe your professional background and education.

A. As a utility pricing and policy expert, I support a variety of energy and utility related projects regarding matters pertaining to economics, finance, and public policy. In the public utility space, I have assisted with asset divestitures, allocated class cost of service studies, rate of return calculations, cash working capital impacts, tax litigation, revenue allocation, rate design, auction analysis, and affiliate cost allocation. I have reviewed and analyzed these subject matters considering the accounting treatment for, the financial investment in, and the operational configuration of a company's assets. For utility rate cases, I have performed: allocated class cost of service studies; revenue allocation; rate design; valuation modeling; affiliate cost allocation; and various cost of service analyses. Also, I have filed testimony on class cost of service studies, return on equity, and statistical audit sampling. Specifically, I have presented expert testimony in Indiana, Maine, Massachusetts, Minnesota, New Hampshire, North Carolina, Illinois, Delaware, Pennsylvania, Washington, West Virginia, British Columbia, and the Federal Energy Regulatory Commission ("FERC"). Regarding my educational background and professional background, I studied electrical and mechanical engineering and worked for an industrial inspection company, which provided hands-on experience with electric utility assets and equipment. I received an undergraduate degree in Environmental Economics, with an emphasis in econometrics and regulatory policy. I also earned a Masters in Economics from American University in Washington, DC. A copy of my resume is provided as UGI Gas Exhibit JDT-1.

Q. Mr. Taylor, have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or any other regulatory authority?

A. Yes. I have presented expert testimony before FERC and numerous state and provincial regulatory commissions, including the Commission.

Q. What is your assignment in this proceeding?

A. UGI Gas requested that Atrium Economics assist with the development of a Weather Normalization Adjustment ("WNA") mechanism that could be applied to the monthly billings of certain UGI Gas's Residential (Rates R and RT) and Non-Residential (Rates N and NT) customer classes. UGI Gas's proposed WNA Rider is presented in UGI Gas Exhibit F – Proposed Tariff, Rider K "WNA", Weather Normalization Adjustment Rider.

Q. Please summarize the content of your testimony.

A. I will present the Company's proposed WNA mechanism, which is designed to stabilize distribution revenues for certain heating sensitive rate classes from experienced weather variability. My testimony consists of (a) support and rationale for a WNA mechanism, (b) a summary of UGI Gas's proposed WNA, (c) detailed components of UGI Gas's proposed WNA, and (d) a summary of weather normalization adjustments used in Pennsylvania and across the U.S.

II. <u>LIST OF EXHIBITS SPONSORED IN TESTIMONY</u>

Q. What Exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following Exhibits:

- UGI Gas Exhibit JDT – 1, Resume;
- UGI Gas Exhibit JDT – 2, Survey of WNA Mechanisms; and
- UGI Gas Exhibit Exhibit F – Proposed Tariff, Rider K "WNA", Weather Normalization Adjustment Rider.

III. <u>SUPPORT & RATIONALE FOR A WNA MECHANISM</u>

Q. How are weather-normalized gas volumes used to derive a gas utility's base rates?

A. Typically, as part of the rate design in a base rate proceeding, a utility's volumetric unit rates for gas service are derived by dividing the appropriate costs, to be recovered through volumetric based rates, by the anticipated weather-normalized gas sales volumes. These rates are designed to provide the utility with an opportunity to recover the costs it incurs to provide utility service, at the levels determined in the utility's rate case under normal weather conditions. To the extent any costs are subject to recovery in a volumetric charge, the recovery of such amounts is entirely dependent upon the volumes of gas usage experienced by the utility. Therefore, the recovery of costs in a volumetric component of rates will always lead to a difference in recovery of actual costs because actual weather conditions will by and large never match the normalized weather conditions used to set rates.

Q. Please explain how weather influences the recovery of costs for a gas utility and costs to customers.

A. As a result of the volumetric rates described above, if actual temperatures are normal (as described in Section V below), the utility has a reasonable opportunity to fully recover its fixed costs of service at established sales levels, and the customers' payment for service reflects the costs of the utility. Unfortunately, normal temperatures seldom, if ever, occur. Therefore, because of abnormal weather and a rate design that is based, in substantial part, on customer usage, the amount of distribution revenue (i.e., non-gas sales revenues and non-reconcilable surcharge revenues) collected from customers can vary widely from the revenue requirement level authorized by the regulator. In the case of warmer weather, the utility may under recover its costs and need to pursue cost management efforts that help stabilize and support the overall financial health and performance of the company. In the case of colder weather, customers experience higher bill cost burdens which may negatively impact customer abilities to manage utility costs.

Q. What portion of UGI Gas's fixed costs is recovered through its current volumetric distribution charges?

A. As shown on UGI Gas Exhibit E – Proof of Revenue, at proposed rates, approximately 64% of distribution revenues for Rates R and RT is recovered through the volumetric distribution charge. For UGI Gas's small commercial customers receiving service under Rates N and NT, approximately 83% of distribution revenue is recovered through the volumetric distribution charge.

Q. Please explain how fluctuations in weather over time impact a gas utility's temperature-sensitive customers and the utility's financial performance.

A. Since the bills of gas customers are largely based on the level of gas usage, temperature-sensitive customers' monthly bills can vary widely due to changing weather conditions. Under traditional ratemaking methods, if actual temperatures were colder than normal, the typical gas customer would use more gas, pay more for service (through volumetric charges), and potentially overpay its share of fixed costs. This occurs because the unit rates used to recover fixed costs are not reduced to recognize the higher gas volumes used by customers during colder weather. Since the gas utility's level of fixed costs does not change, the higher gas volumes applied against the same unit rate would generate comparatively higher distribution revenues than the level of fixed costs established for ratemaking purposes. Conversely, in warmer than normal weather, the reverse situation would occur. Customers' gas usage decreases with warmer temperatures, thus generating comparatively lower distribution revenues than required to recover the gas utility's total fixed costs that do not decrease due to warm weather.

IV. PROPOSED WNA MECHANISM

Q. Please define and describe the concept of a WNA mechanism.

A. The utility's distribution rates, which are set to allow the utility to recover its authorized level of distribution revenues, are based on expected throughput during normal weather. When actual weather deviates from normal weather, there will be a difference between actual and projected distribution revenues. A WNA mechanism adjusts a customer's bill due to these variations from normal weather (i.e., temperature variations or heating degree day variations) in order to have the bill reflect normal weather conditions. For billing periods that are colder than normal, a credit will be applied to the bill. For billing periods that are warmer than normal, a surcharge is applied to the bill. WNA mechanisms are typically effective for usage during the heating season calendar months (e.g., October through May). WNAs reduce the amount of variation in both customer bills and utility revenues by making a compensating adjustment for the difference between actual weather and normal weather.

Q. Are WNA mechanisms different from Revenue Decoupling?

A. Revenue Decoupling is a regulatory mechanism that separates a utility's distribution revenues from its level of sales, thereby "breaking the link" so that the utility may recover an established amount of revenues (regardless of weather, customer conservation, etc.), even as sales fluctuate. WNA mechanisms only account for the changes in sales that occur due to the difference between actual weather and normal weather. In the case of the Company's specific proposal, the WNA will only address weather related impacts and will only do so for certain of the Company's customer classes; thus, while providing a level of revenue stability related to weather changes, it does not completely decouple revenues from all sales related variances as full revenue decoupling would provide.

Q. Do WNA mechanisms differ in their design?

A. Yes. Gas utilities typically use two types of WNA mechanisms: (1) a mechanism that adjusts current billings on a monthly billing basis as the bill is being calculated and issued; and (2) a mechanism that adjusts billings on a lagged basis where the adjustment appears on the customer's bill(s) from a few to several months after a variation from normal weather is experienced.

Q. Which type of WNA mechanism is the Company proposing to implement?

A. The Company proposes to implement a WNA mechanism that adjusts billings on a monthly billing basis as the bill is being calculated and issued.

Q. Why has the Company chosen to adopt a WNA mechanism of this type?

UGI Gas has chosen this type of WNA mechanism because, by adjusting current billings on a monthly billing basis, the customer can more readily link the resulting billing adjustment with the weather causing the adjustment. In a cold winter with high gas bills, customers will receive the benefits of WNA bill reductions more quickly. The monthly bills will reflect the specific period in which the colder weather occurs. In addition, the utility's financial statements will reflect the cash flow effect of the monthly billing WNA mechanism sooner than a lagged WNA mechanism.

Q. Please describe the Company's proposed WNA.

A. The key elements of the Company's proposed WNA mechanism are as follows:

- It applies to UGI Gas's Residential customers receiving service under Rates R and RT and UGI Gas's Non-Residential customers served under Rates N and NT.
- It adjusts billings on a current monthly basis and uses adjustment factors which are representative of each customer's consumption characteristics.
- It is effective for the billing months of October through May.
- It adjusts the amount billed to each customer to offset the impact of actual heating degree days ("AHDD") variations from normal heating degree days ("NHDD").

Q. What are the benefits of the weather normalization adjustment mechanism for UGI Gas and its customers?

A. For an applicable customer, a WNA is advantageous because:

1. It reduces bill variability due to weather in the month when the variation occurs and provides bill relief in severely cold months.
2. The WNA will improve customer satisfaction by providing more stable annual bill amounts and mitigating volatility in monthly gas bills. This will help customers budget for and pay their bills.
3. Customers will continue to benefit from their energy conservation efforts, as the actual usage on each customer's bill is utilized to calculate the WNA adjustment, and that usage level will reflect the conservation behaviors of each customer.

For UGI Gas, a WNA is a fair and equitable rate mechanism because:

1. UGI Gas's volumetric delivery service rates are based on the volumes of gas it expects to sell under normal weather conditions. The WNA mechanism will improve the ability to match the level of distribution revenues, established to recover fixed costs, with the amount reflected in the monthly customer billings.
2. Deviations from normal weather can result in differences in actual and projected recovery of the Company's annual non-gas distribution costs when actual weather experienced is colder or warmer than normal, respectively. Therefore, such deviations can produce erratic financial results for the Company.

Q. Is UGI Gas's proposed WNA similar to other WNA mechanisms in place for gas distribution utilities in Pennsylvania?

A. Yes. UGI Gas's proposed WNA shares similarities with both Columbia Gas of Pennsylvania's ("Columbia") WNA rider,[1] and Philadelphia Gas Works' ("PGW") WNA clause.[2] The WNA applies to Residential heating customers for all three utilities, and Non-Residential heating customers for UGI Gas and PGW. The specific calculation of UGI Gas's proposed WNA rate is most similar to the calculation of Columbia's WNA rider.[3] Finally, like Columbia and PGC, UGI Gas is proposing annual reporting for the WNA to the Commission and only applies only during the heating season months.

[1] Columbia Gas of Pennsylvania, Inc., "Rider WNA – Weather Normalization Adjustment", Rates and Rules for furnishing gas service, https://www.columbiagaspa.com/docs/librariesprovider14/rates-and-tariffs/pennsylvania-tariff.pdf?sfvrsn=41, pdf at page 187.

[2] Philadelphia Gas Works, "Weather Normalization Adjustment Clause", Gas Service Tariff, https://www.pgworks.com/uploads/pdfs/PGW_Gas_Service_Tariff_Through_Supplement_145.pdf, pdf at page 150.

[3] There are a few differences in function. Columbia uses a November through May heating season and applies a 3% deadband, whereas PGW uses a heating season of October through May and applies a 1% deadband.

V. <u>COMPONENTS OF UGI GAS'S PROPOSED WNA MECHANISM</u>

Q. Please explain how UGI Gas's proposed WNA mechanism will operate.

A. UGI Gas's proposed WNA mechanism will adjust the amount billed to each customer served under Rates R, RT, N, and NT to effectively weather normalize distribution revenues recovered from these two rate schedules during the cold weather heating season. It is a customer bill specific calculation applied to monthly billing cycles during the months of October through May.

Q. What is the Company's basis for determining normal weather for its Pennsylvania gas distribution system?

A. Since 2009, UGI Gas has defined normal weather as the average annual heating degree days ("HDD") calculated for a 15-year period, with the most recent period ending December 31, 2019. It is updated every 5 years with the next recalculation due for the period ending December 31, 2024. This is further discussed in the direct testimony of Company witness Sherry A. Epler (UGI Gas Statement No. 8).

Q. Would the adjustment to customers' bills be calculated on a calendar month or on a billing cycle month basis?

A. The customer adjustments would be made on a billing cycle basis. This approach allows the adjustments to be calculated at the end of each customer's meter reading billing cycle and incorporated into the original bill sent to each customer. This approach provides for an accurate and timely adjustment for the customer. There is no additional time lag between when the customer experiences the bill variability and when the weather normalizing adjustment is made.

Q. In the context of WNA riders, what are deadbands?

A. A deadband applies to WNA riders such that the adjustment is not triggered if AHDDs are within a certain threshold of the NHDDs. Thus, no adjustment applies to the bill if weather falls within that threshold and some weather variability flows to customer bills and is seen in the associated utility distribution revenues. Columbia's WNA mechanism utilizes a 3% deadband, and PGW's WNA mechanism utilizes a 1% deadband.

Q. Does UGI Gas's proposal include a deadband?

A. No. The UGI Gas proposal does not include a deadband. The Company believes the application of a deadband adds unnecessary complexity to the rider, which is a concern for customer communication and education. Also, in principle, the WNA's intended goal is to stabilize billings and distribution revenues from readily identified weather related variances, not just "some" element of weather variance that may be arbitrarily established.

Q. Please provide a formulaic representation of the WNA mechanism that you just described.

A. The Company's proposed WNA formula that is applied to bills of Residential and Non-Residential customers under Rate Schedules R/RT and N/NT for the heating season of October through May is shown below:[4]

$$\mathrm{WNBC} = \mathrm{BLMC} + \left[\frac{\mathrm{NHDD}}{\mathrm{AHDD}} \mathrm{x}\ (\mathrm{AMC} - \mathrm{BLMC})\right]$$

$$\mathrm{WNAC} = \mathrm{WNBC} - \mathrm{AMC}$$

$$\mathrm{WNA} = \mathrm{WNAC}\ \mathrm{x}\ \mathrm{Distribution\ Charge}$$

- <u>WNA</u> = Weather Normalization Adjustment will be applied to bills of Residential and Non-Residential customers under Rate Schedules R/RT and N/NT, for any billing period during the heating season October through May. WNA will not be applicable for the billing period if AMC is less than the BLMC.

- <u>WNBC</u> = Weather Normalized Billing Ccfs ("WNBC") will be calculated as the Base Load Monthly Ccfs ("BLMC") added to the product of (1) the Normal Heating Degree Days ("NHDD") divided by the Actual Heating Degree Days ("AHDD") and (2) the Actual Monthly Ccfs ("AMC") less the BLMC. Weather Normalized Billing Ccfs (WNBC) will only be calculated if the AMC exceeds the BLMC.

- <u>BLMC</u> = Base Load Monthly Ccfs for each customer shall be established for each customer using the customer's actual average daily consumption from the billing system, measured in Ccfs, using bills with read dates of June 21st thru September 20th over a 36-month period multiplied by the number of days in the billing period. The average daily base load is recalculated monthly using the most recent 36 months of bill history. If less than 12 months of bill history is available for the customer, an average base load for the related customer class will be applied.

- <u>NHDD</u> = Normal Heating Degree Days shall be applied on a Delivery Region specific basis as determined by the customer's geographical location and, for any given day within a billing period, shall be based upon the Delivery Region's 15-year average for the given day. NHDD shall be updated every 5 years using the methodology established in the Company's general rate case proceeding at R-2021-3030218 with the next scheduled update of the NHDD to be effective on October 1, 2025, and thereafter every 5 years.

[4] The full proposed tariff language is provided as UGI Gas Exhibit F – Current Tariffs, Rate Schedule "WNA", Weather Normalization Adjustment Rider.

- AHDD = Actual Heating Degree Days shall be the actual experienced heating degree days during the billing cycle for the customer's assigned Delivery Region, as determined by the customer's geographical location. A Delivery Region's AHDD shall be based upon experienced actual Gas Day temperatures as reported by the National Oceanic and Atmospheric Administration (NOAA) for weather stations located within that Delivery Region pursuant to the application of the Company's established Delivery Region calculation methodology.

- The period for which both NHDD and AHDD will be measured for each billing period used for the WNA calculation will be based on the starting day of the customer's billing cycle minus one day through last day of customer's billing cycle minus one day. If AHDD is unavailable for any day(s) during that period, the respective NHDD for the same day(s) will also be excluded from the calculation, thereby excluding any days missing AHDD from the WNBC calculation.

- AMC = Actual Monthly Ccfs will be subtracted from the WNBC to compute the Weather Normalized Adjustment Ccfs ("WNAC").

- The WNAC shall then be multiplied by the applicable Rate Schedule Distribution Charge based on service rendered to compute the WNA amount that will be charged or credited to each Residential and Non-Residential customer served under Rate Schedules R, RT, N and NT.

Q. Please explain the process the Company will follow to calculate the WNA.

A. For each billing cycle, the Company will adjust the heat sensitive load to account for the ratio of normal weather to actual weather and then recalculate the bill. The process works as follows:

- For each billing cycle and each applicable customer, the Company will calculate the weather normalized billing Ccfs by multiplying the heat sensitive load (actual Ccfs less base load Ccfs) times the ratio of the normal HDDs for the billing cycle to the actual HDDs; i.e., $\left[\frac{\text{NHDD}}{\text{AHDD}} \text{x} (\text{AMC} - \text{BLMC})\right]$. This adjusted heat sensitive load will then be added to the base load Ccfs to calculate the Weather Normalized Billing Ccfs (WNBC); i.e., $\text{WNBC} = \text{BLMC} + \left[\frac{\text{NHDD}}{\text{AHDD}} \text{x} (\text{AMC} - \text{BLMC})\right]$.

- The Company will then determine the Weather Normalized Adjustment Ccfs ("WNAC") of each applicable customer for each billing cycle by subtracting the actual monthly Ccfs from the Weather Normalized Billing Ccfs; i.e., WNAC = WNBC-AMC.

- This Weather Normalized Adjustment Ccfs is then multiplied by the applicable rate class's volumetric distribution charge to develop the Weather Normalization Adjustment that will be applied on the customer's bill. WNA=WNAC x Distribution Charge.

Q. Have tariff pages been developed that reflect the computational details and process of the proposed WNA mechanism?

A. Yes. The appropriate tariff pages to implement the proposed WNA mechanism are presented in UGI Gas Exhibit F (Proposed Tariff), Rider C - "WNA", Weather Normalization Adjustment Rider.

Q. When does the Company propose to implement the WNA?

A. Although intended to apply for bills during the months of October through May on a forward basis, assuming the effective date of new rates is in October 2022 in this proceeding, UGI Gas is proposing the WNA will initially be implemented beginning with bills rendered on and after November 1, 2022. Thereafter in subsequent years, the WNA will apply for billings during each October through May period.

Q. What additional filing(s) would occur related to the Weather Normalization Adjustment Rider?

A. The Company will file weather normalization information with the Commission annually on or before December 1st for WNA data related to the 12-month period ending September of that same year. The filing will contain the following information on the WNA mechanism: (a) monthly WNA billed revenue; and (b) monthly actual and normal HDD data.

Q. How does the proposed WNA align with the Statements of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883?

A. Each rate consideration identified in the Statement of Policy is listed below along with the relevant effect the proposed WNA has on each rate consideration:

1. Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

- UGI Gas's proposed WNA is designed to recover distribution revenues needed to satisfy the cost-of-service requirement determined in this proceeding, while mitigating the variance between actual and projected distribution revenues due to weather. UGI Gas recovers a significant portion of fixed costs through volumetric rates. These fixed costs do not vary with the amount of gas delivered to customers and are composed of fixed operation and maintenance ("O&M") expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. In the absence of Straight Fixed Variable ("SFV") rate design; where all fixed costs are recovered in a fixed monthly charge, a WNA mechanism will better align distribution revenues with cost causation principles; appropriately accounting for variation in usage due to weather.

2. Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

- UGI Gas's WNA proposal has no identifiable impact on capacity utilization.

3. Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

- Customer specific usage factors corresponding to their individual demand (the BLMC for each customer) is continually updated and reflects the level of demand associated with the customer's anticipated consumption levels.

4. *<u>How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting</u>.*

- Since the proposed WNA mechanism is applying rates which are based upon the specific revenue allocation and rate design approved by the Commission, it will mitigate the potential for interclass or intraclass cost shifting related to weather driven usage variances from those weather assumptions used in establishing rates.

5. *<u>Please explain how the WNA limits or eliminates disincentives for the promotion of efficiency programs</u>.*

- The proposed WNA only addresses variations due to weather. The WNA does not negatively impact energy efficiency programs. Moreover, UGI Gas maintains a robust Energy Efficiency & Conservation ("EE&C") program, which it has voluntarily implemented for its customers and will use to continue promoting energy efficiency measures.

6. *<u>Please explain how the WNA impacts customer incentives to employ efficiency measures and distributed energy resources</u>.*

- Customers will continue to have an incentive to employ energy efficiency measures and distributed energy resources because a reduction in usage still reduces their overall bill and the portion of their bill that is subject to the WNA mechanism.

7. *<u>Please explain how the WNA impacts low-income customers and support consumer assistance programs</u>.*

- Under the WNA mechanism, certain customers enrolled in the Customer Assistance Program ("CAP") who pay an "average bill" amount will see lower bill variability for distribution costs during colder than average periods, while CAP customers who are paying on a percent-of-income basis will see little to no impact.

8. *<u>Please explain how the WNA impacts customer rate stability principles</u>.*

- The WNA mechanism will provide customers more stable annual bills and directly mitigate volatility in their monthly costs.

9. *<u>Please explain how weather impacts utility revenue under the WNA</u>.*

- The proposed WNA adjusts a customer's bill due to variations from normal weather and is employed for usage during the heating season months (October – May). It only applies to certain of the Company's customer classes (Rates R, RT, N and NT) and it does not ensure the utility will recover 100% of its authorized distribution revenues, but it does reduce the amount of weather-related variation in both customer bills and associated utility distribution revenues.

10. *Please explain how the WNA impacts the frequency of rate case filings and affects regulatory lag*.

- The WNA is not anticipated to impact the frequency of rate cases or have an impact on regulatory lag.

11. *Please explain if the WNA interacts with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge)*.

- The Company's proposed WNA (appearing as Rider C – WNA in the Tariff) only applies to distribution related charges that are recovering the base distribution revenue requirement from applicable WNA customer classes for the heating season of October through May. Specifically, the billing for the Company's Riders, including Rider F – USP, Rider G – EE&C, and Rider B – PGC, will continue to be based on actual monthly usage.

12. *Please explain whether the WNA includes appropriate consumer protections*.

- The WNA mechanism will result in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates. UGI Gas will not recover additional distribution revenues due to colder than average temperatures that result in higher-than-normal usage from customers.

13. *Please explain whether the WNA is understandable to customers*.

- UGI Gas's WNA is not a new concept to the regulated utility industry. Similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. UGI Gas has proposed a WNA tariff that provides detailed information to the customer of how the mechanism works based on successful working versions found in the tariffs of other Pennsylvania natural gas distribution companies that have implemented a WNA tariff. Further, educational materials and customer service training will be developed upon approval of the mechanism, as well as appropriate notice being provided to customers related to the WNA being approved pursuant to the Commission's alternative ratemaking notice requirements.

14. *Please explain how the WNA will support improvements in utility reliability*.

- UGI Gas's cost of service is inclusive of investments and costs to continue to enhance the safety and reliability of its system. The proposed WNA will help minimize the volatility of the recovery of these costs.

VI. WIDESPREAD INDUSTRY USE OF WNA MECHANISMS

Q. Are WNA mechanisms like the one the Company proposes widely accepted in the natural gas industry?

Yes. UGI Gas Exhibit JDT – 2 presents a survey conducted by Atrium Economics, with input from an American Gas Association survey,[5] which shows that many U.S. gas utilities, across a wide geographic area, have implemented WNA mechanisms. Specifically, the survey results (provided in Figure 1 below) show there are 27 states that have approved WNAs for gas companies serving 66 different service territories. Currently, As of November 2021, Atrium's research indicates that two additional gas utilities, Duke Energy in Kentucky and New Mexico Gas, have pending WNA proposals before their respective regulatory commissions. While four other gas utilities in Kentucky already have WNA mechanisms in operation, New Mexico would be added to the list of states if New Mexico Gas's WNA proposal is approved.

[5] American Gas Association "Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List" site: https://www.aga.org/sites/default/files/aga_innovative_rates_december_2016.pptx

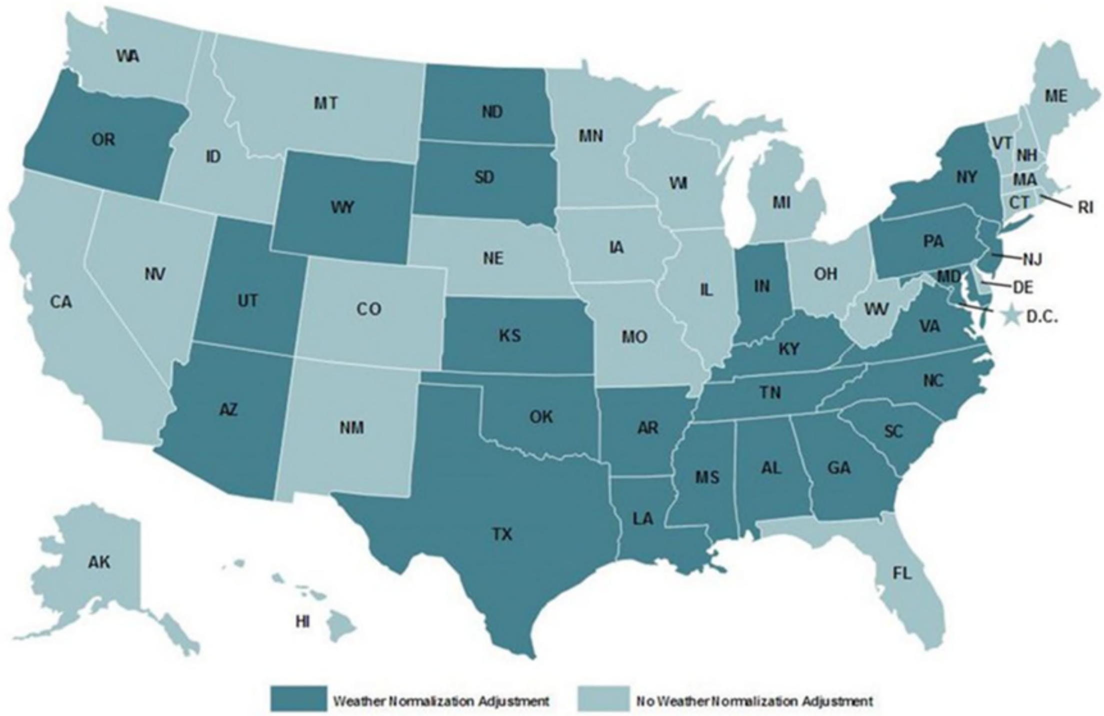

Figure 1 – Map of US States with WNA Mechanisms

Q. Are decoupling mechanisms common across the industry?

A. Yes, decoupling mechanisms are an increasingly common ratemaking tool throughout the natural gas industry. Table 1 below summarizes various approved and proposed decoupling mechanisms for 40 states in the U.S. and the District of Columbia. Along with WNAs, Revenue Normalization Adjustments ("RNA") and Straight Fixed Variable ("SFV") rate design make up the other decoupling mechanisms noted.

Table 1 – RNA, SFV, and WNA Mechanisms across the U.S.

	Decoupling Mechanism				Decoupling Mechanism		
State Name	**RNA**	**SFV**	**WNA**	**State Name**	**RNA**	**SFV**	**WNA**
Alabama			WNA	Nevada	RNA		
Arizona	RNA		WNA	New Hampshire	Proposed		
Arkansas	RNA		WNA	New Jersey	RNA		WNA
California	RNA			New York	RNA		WNA
Connecticut	RNA			North Carolina	RNA		WNA
Delaware	Proposed			North Dakota		SFV	WNA
Florida		SFV		Ohio		SFV	
Georgia		SFV	WNA	Oklahoma		SFV	WNA
Idaho	RNA			Oregon	RNA		WNA
Illinois	RNA	SFV		Pennsylvania			WNA
Indiana	RNA		WNA	Rhode Island	RNA		
Kansas			WNA	South Carolina			WNA
Kentucky			WNA	South Dakota			WNA
Louisiana			WNA	Tennessee	RNA		WNA
Maryland	RNA		WNA	Texas			WNA
Massachusetts	RNA			Utah	RNA		WNA
Michigan	RNA			Virginia	RNA		WNA
Minnesota	RNA			Washington	RNA		
Mississippi			WNA	Wyoming	RNA		WNA
Nebraska		SFV		Washington, D.C.	Proposed		

Q. Do any members of the peer group used to inform the recommended return on equity for UGI Gas in this proceeding have similar mechanisms?

A. Yes, as indicated above WNA mechanisms and decoupling mechanisms are common ratemaking mechanisms across the industry. As indicated in the testimony of Company witness Paul R. Moul (UGI Gas Statement No. 6), the utilities included in his Gas Group (the peer group) already have tariff mechanisms for stabilization of revenues due to variation in weather, either through similar WNA mechanisms as that proposed by UGI

Gas or through full revenue decoupling mechanisms. The implementation of UGI Gas's proposed WNA mechanism would place UGI Gas on a more comparable footing to the benchmark proxy group that Paul R. Moul uses in his direct testimony to establish the proposed return on equity.

Q. Have WNA proposals recently been authorized by the Commission?

A. Yes. In a December 6, 2018 Order, the Commission authorized the continuation of Columbia's WNA mechanism that had earlier been implemented on a pilot basis. Chairperson Gladys Brown Dutrieuille, provided the following statement in the Order supporting the continuation of the WNA mechanism:

> "I commend the parties for their commitment to this mechanism. … The Weather Normalization Adjustment works bi-directionally to insulate customers from high bills during the extremely cold months, while also limiting the decline in revenue for Columbia during unseasonably warm heating months. This…stabilizes Columbia's cash flow, and in turn, allows Columbia to more acutely focus on operational items within its control; namely infrastructure upgrades and repairs. Further, since this decoupling mechanism is only applied to the distribution component of the bill, and not the natural gas commodity charge, incentives for efficient consumption are maintained." [6]

Q. Do you believe UGI Gas's proposed WNA mechanism is fair to both the Company and its customers?

A. Yes. The proposed WNA mechanism strikes an appropriate balance between the interests of both the Customer and the Company. UGI Gas would be simply billing its customers in a manner to reflect the normal weather conditions that underlie its Commission-

[6] Pennsylvania Public Service Commission Docket No. R-2018-2647577.

authorized base rates on a monthly billing basis. Moreover, the WNA mechanism provides the Company a reasonable opportunity to earn its allowed rate of return on its investment and removes bill variability due a factor outside of customer's control, variations in weather.

VII. CONCLUSION

Q. Please summarize how implementing the proposed WNA mechanism results in fair and equitable ratemaking.

A. The Company's proposed WNA mechanism results in fair and equitable ratemaking due to the following:

- The WNA helps to break the link between the gas consumption of the Company's customers and its distribution revenue recovery, and better aligns the interests of UGI Gas and its customers. The fixed costs embedded in UGI Gas's volumetric rates for distribution service do not vary in the short-term with changes in temperature.

- The WNA addresses a factor beyond the Company's and customers' control, weather variability. This variability contributes to increased volatility in customers' bills, and increased volatility in the Company's recovery of costs.

- Customers receive greater stability in the non-gas portion of their utility bills, a benefit during the winter months when gas prices tend to be at their highest, and a particular benefit for low-income customers with high bills during the lengthy heating seasons in UGI Gas's service areas.

For these reasons, I urge the Commission to approve the Company's proposed WNA mechanism.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS

EXHIBIT JDT-1

ATRIUM ECONOMICS
CENTERED ON ENERGY

John D. Taylor

Managing Partner

Mr. Taylor is a utility pricing expert with experience developing cost of service studies for both electric and gas utilities and transmission companies. He has deep experience with developing residential and commercial rates, analyzing midstream transportation and storage capacity resources, and assessing the relationship between price signals and the adoption of distributed generation assets.

He has filed testimony as an expert witness on class cost of service studies for both electric and natural gas utilities, return on equity, and on the appropriate use of statistical analysis during audit testing. Mr. Taylor has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. He has an expert knowledge of cost allocation principles for utility cost of service studies and for affiliate transaction and service agreements. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He has also been involved in the sale of generating assets as sell side advisors, supporting due diligence efforts, financial analyses, and regulatory approval processes.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

15

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

EXPERT WITNESS TESTIMONY PRESENTATION

United States

- Delaware Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

Canada

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

Rate Design and Regulatory Proceedings

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.
- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission’s audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Financial Analysis and Market Research

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Developed distributed CNG/LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

UGI GAS

EXHIBIT JDT-2

Company	State	Tariff Available	Year Approved
ENSTAR Natural Gas Company	Alaska	none	
Spire Alabama, Inc.	Alabama	Temperature Adjustment Rider	2018
Spire Gulf, Inc.	Alabama	Weather Impact Normalization Factor (WINF)	2017
Arkansas Oklahoma Gas Corp.	Arkansas	Weather Normalization Adjustment (WNA)	2018
Black Hills Energy Arkansas, Inc. (d/b/a Black Hills Energy)	Arkansas	Weather Normalization Adjustment (WNA) Rider	2018
CenterPoint Energy Resources Corp.	Arkansas	Weather Normalization Adjustment (WNA)	
Arizona Public Service Company	Arizona	Lost Fixed Cost Recovery (LFCR) Mechanism	2020
Southwest Gas Corporation	Arizona	Delivery Charge Adjustment (DCA) Provision (Decoupling Mechanism)	2021
UNS Gas, Inc.	Arizona	Lost Fixed Cost Recovery (LFCR)	
Pacific Gas & Electric Company	California		
San Diego Gas & Electric Company	California		
Southern California Gas Company	California		
Southwest Gas Corporation	California	Fixed Cost Adjustment Mechanism (FCAM)	2014
Atmos Energy Corporation	Colorado	General Rate Schedule Adjustment (GRSA) Rider	
Black Hills Colorado Gas, Inc. (d/b/a Black Hills Energy)	Colorado	none	
Rocky Mountain Natural Gas, LLC (d/b/a Black Hills Energy)	Colorado	none	
Public Service Company of Colorado (d/b/a Xcel Energy)	Colorado	Pilot Revenue Decoupling Mechanism (RDM)	
Connecticut Natural Gas Corporation (d/b/a Avangrid)	Connecticut	Decoupling Mechanism	
Southern Connecticut Gas Company (d/b/a Avangrid)	Connecticut	Decoupling Mechanism	
Yankee Gas Services Company (d/b/a Eversource)	Connecticut	Revenue Decoupling Mechanism (RDM) Rider	
Washington Gas Light Company	DC	Gas Supply Realignment Adjustment (GSRA)	
Washington Gas Light Company	DC	Plant Recovery Adjustment (PRA)	2011
Chesapeake Utilities Corporation	Delaware	none - legislature-mandated revenue decoupled rate designs were repealed in 2009	
Delmarva Power & Light Company	Delaware	none - legislature-mandated revenue decoupled rate designs were repealed in 2009	
Florida Public Utilities Company	Florida	none	
Peoples Gas System (a division of Tampa Electric Co) (d/b/a Emera)	Florida	none	
Atlanta Gas Light Company	Georgia	Georgia Rate Adjustment Mechanism (GRAM)	
Black Hills Iowa Gas Utility Company, LLC (d/b/a Black Hills Energy)	Iowa	none	
Interstate Power and Light Company (d/b/a Alliant Energy)	Iowa	none	
MidAmerican Energy Company (d/b/a Berkshire Hathaway Energy)	Iowa	none	
Avista Corporation	Idaho	Fixed Cost Adjustment Mechanism	
Intermountain Gas Company (d/b/a MDU Resources Group)	Idaho	none	

Company	State	Tariff Available	Year Approved
Ameren Illinois Company (d/b/a Ameren)	Illinois	none	
MidAmerican Energy Company (d/b/a Berkshire Hathaway Energy)	Illinois	none	
Northern Illinois Gas Company	Illinois		
North Shore Gas Company	Illinois		
Peoples Gas Light and Coke Company	Illinois		
Indiana Gas Company, Inc. (d/b/a CenterPoint Energy Resources Corp.)	Indiana	Normal Temperature Adjustment (NTA)	2008
Northern Indiana Public Service Company (d/b/a NiSource)	Indiana	none	
Southern Indiana Gas & Electric Company (d/b/a CenterPoint Energy Resources Corp.)	Indiana	Normal Temperature Adjustment (NTA)	2021
Atmos Energy Corporation	Kansas	Weather Normalization Adjustment (WNA) Rider	
Black Hills Kansas Gas Utility Company, LLC (d/b/a Black Hills Energy)	Kansas	Weather Normalization Adjustment (WNA) Rider	2015
Kansas Gas Service Company, Inc. (d/b/a ONE Gas)	Kansas	Weather Normalization Adjustment (WNA) Rider	2019
Atmos Energy Corporation	Kentucky	Weather Normalization Adjustment (WNA) Rider	
Columbia Gas of Kentucky, Inc. (d/b/a NiSource)	Kentucky	Weather Normalization Adjustment (WNA)	2009
Delta Natural Gas Company, Inc.	Kentucky	none	
Duke Energy Kentucky, Inc. (d/b/a Duke Energy)	Kentucky	Weather Normalization Adjustment (WNA) Rider	2019
Louisville Gas & Electric Company	Kentucky	Weather Normalization Adjustment (WNA) Clause	2019
Atmos Energy Corporation	Louisiana	Rate Stabilization Clause - Rider RSC	
Atmos Energy Corporation	Louisiana	Weather Normalization Adjustment - Rider WNA	
Entergy Louisiana, LLC (d/b/a Entergy)	Louisiana	Rate Stabilization Plan (RSP) Rider	2020
Entergy New Orleans, LLC (d/b/a Entergy)	Louisiana	Gas Formula Rate Plan Rider	2020
CenterPoint Energy Resources Corp.	Louisiana	Weather Normalization Adjustment (WNA) Rider	
Columbia Gas (Bay State Gas Company) of Massachusetts, Inc. (d/b/a Eversource)	Massachusetts	Revenue Decoupling Adjustment Clause (RDAC)	2020
The Berkshire Gas Company (d/b/a Avangrid)	Massachusetts	Revenue Decoupling Adjustment Clause	2020
Boston Gas Company (d/b/a National Grid)	Massachusetts	Revenue Decoupling Mechanism Clause	2018
Colonial Gas Company (d/b/a National Grid)	Massachusetts	Revenue Decoupling Mechanism Clause	2018
Fitchburg Gas & Electric Light Company (d/b/a Unitil)	Massachusetts	Revenue Decoupling Adjustment Clause	2020
Liberty Utilities (New England Natural Gas Company) Corporation (d/b/a Liberty Utilities)	Massachusetts	Revenue Decoupling Adjustment Clause	2019
NSTAR Gas Company (d/b/a Eversource)	Massachusetts	Revenue Decoupling Adjustment Clause	2020

Company	State	Tariff Available	Year Approved
Baltimore Gas & Electric Company	Maryland		
Chesapeake Utilities Corporation	Maryland		
Columbia Gas of Maryland, Inc. (d/b/a NiSource)	Maryland	Weather Normalization Adjustment (WNA)	2016
Washington Gas Light Company	Maryland		
Maine Natural Gas (d/b/a Avangrid)	Maine	none	
Summit Natural Gas of Maine, Inc.	Maine	none	
Consumers Energy Company	Michigan	RDM authorized in Sept 2019	
DTE Gas Company	Michigan	RDM authorized in Sept 2018	
Michigan Gas Utilities Corporation	Michigan	terminated RDM in 2015	
CenterPoint Energy Resources Corp.	Minnesota	Revenue Decoupling Rider (RD Rider)	
Minnesota Energy Resources Corporation	Minnesota	Revenue Decoupling Mechanism (RDM)	2019
Northern States Power Company (d/b/a Xcel Energy)	Minnesota	State Energy Policy Rate Rider	
Empire District Gas Company (d/b/a Liberty Utilities)	Missouri	none	
Midstates Natural Gas Corporation (d/b/a Liberty Utilities)	Missouri	Weather Normalization Adjustment Rider (WNAR)	2020
Missouri Gas Energy (d/b/a Spire)	Missouri	Weather Normalization Adjustment Rider (WNAR)	2018
Spire Missouri, Inc. (d/b/a Spire)	Missouri	Weather Normalization Adjustment Rider (WNAR)	2018
Summit Natural Gas of Missouri, Inc.	Missouri	none	
Atmos Energy Corporation	Mississippi	Weather Normalization Adjustment (WNA) Rider	
Atmos Energy Corporation	Mississippi	Stable Rate Adjustment (SRA) Rider	
CenterPoint Energy Resources Corp.	Mississippi	Weather Normalization Adjustment (WNA)	2012
MDU Resources Group, Inc.	Montana	none	
NorthWestern Corporation	Montana		
Piedmont Natural Gas Company, Inc. (d/b/a Duke Energy)	North Carolina	Margin Decoupling Tracker	2008
Public Service Company of North Carolina, Inc. (d/b/a Dominion Energy)	North Carolina	Customer Usage Tracker - Rider C	
MDU Resources Group, Inc.	North Dakota	Distribution Delivery Stabilization Mechanism (DDSM)	
Northern States Power Company (d/b/a Xcel Energy)	North Dakota		
Black Hills Nebraska Gas, LLC (d/b/a Black Hills Energy)	Nebraska	none	
NorthWestern Energy	Nebraska	none	
MidAmerican Energy Company (d/b/a Berkshire Hathaway Energy)	Nebraska	none	
Liberty Utilities (EnergyNorth Natural Gas) Corp.	New Hampshire	Normal Weather Adjustment (NWA) - effective Nov. 1, 2021	2021
Northern Utilities, Inc. (d/b/a Unitil)	New Hampshire		
Elizabethtown Gas Company	New Jersey		
New Jersey Natural Gas Company	New Jersey		
Public Service Electric and Gas Company	New Jersey		
South Jersey Gas Company	New Jersey		
New Mexico Gas Company, Inc. (d/b/a Emera)	New Mexico	none	

Company	State	Tariff Available	Year Approved
Sierra Pacific Power Company (d/b/a NV Energy)	Nevada	Deferred Energy Accounting Adjustment (DEAA)	2021
Southwest Gas Corporation	Nevada	General Revenues Adjustment Mechanism (GRAM)	2020
Consolidated Edison Company of New York, Inc. (d/b/a Consolidated Edison, Inc.)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	2020
Consolidated Edison Company of New York, Inc. (d/b/a Consolidated Edison, Inc.)	New York	Weather Normalization Adjustment (WNA)	2019
KeySpan Gas East (Brooklyn Union of Long Island) Corporation (d/b/a National Grid)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	
KeySpan Gas East (Brooklyn Union of Long Island) Corporation (d/b/a National Grid)	New York	Weather Normalization Adjustment (WNA)	2021
Niagara Mohawk Power Corporation (d/b/a National Grid)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	2018
Niagara Mohawk Power Corporation (d/b/a National Grid)	New York	Weather Normalization Adjustment (WNA)	2018
Orange and Rockland Utilities, Inc. (d/b/a Consolidated Edison, Inc.)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	2019
Orange and Rockland Utilities, Inc. (d/b/a Consolidated Edison, Inc.)	New York	Weather Normalization Adjustment (WNA)	2019
Rochester Gas & Electric Corporation (d/b/a Avangrid)	New York	Revenue Decoupling Mechanism (RDM) Adjustment	2020
Rochester Gas & Electric Corporation (d/b/a Avangrid)	New York	Weather Normalization Adjustment (WNA)	2016
Columbia Gas of Ohio, Inc. (d/b/a NiSource)	Ohio	none	
Duke Energy Ohio, Inc. (d/b/a Duke Energy)	Ohio	none	
The East Ohio Gas Company (d/b/a Dominion Energy)	Ohio	none	
Vectren Energy Delivery of Ohio, Inc.	Ohio		
Oklahoma Natural Gas Company (d/b/a ONE Gas)	Oklahoma	Temperature Adjustment Clause	2010
CenterPoint Energy Resources Corp.	Oklahoma	Weather Normalization Adjustment (WNA)	
Arkansas Oklahoma Gas Corp.	Oklahoma	Weather Normalization Adjustment (WNA)	
Avista Corporation	Oregon	Decoupling Mechanism	
Cascade Natural Gas Corporation	Oregon		
Northwest Natural Gas Company	Oregon		

Company	State	Tariff Available	Year Approved
Columbia Gas of Pennsylvania, Inc. (d/b/a NiSource)	Pennsylvania	Rider WNA - Weather Normalization Adjustment	2013
National Fuel Gas Distribution Corporation	Pennsylvania	none	
PECO Energy Company (d/b/a Exelon)	Pennsylvania	none	
Peoples Natural Gas Company, LLC	Pennsylvania	none	
Peoples TWP LLC	Pennsylvania	none	
Philadelphia Gas Works	Pennsylvania	Weather Normalization Adjustment Clause	2002
Narragansett Electric Company	Rhode Island		
Piedmont Natural Gas Company, Inc. (d/b/a Duke Energy)	South Carolina		
Dominion Energy South Carolina, Inc.	South Carolina		
MDU Resources Group, Inc.	South Dakota	Distribution Delivery Stabilization Mechanism (DDSM)	
NorthWestern Corporation	South Dakota		
MidAmerican Energy Company (d/b/a Berkshire Hathaway Energy)	South Dakota	none	
Piedmont Natural Gas Company, Inc. (d/b/a Duke Energy)	Tennessee	Weather Normalization Adjustment (WNA) Rider	
Chattanooga Gas Company	Tennessee		
Atmos Energy Corporation	Tennessee	Weather Normalization Adjustment (WNA) Rider	
CenterPoint Energy Resources Corp.	Texas	none	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (Borger/Skellytown Serv Area)	Texas	Weather Normalization Adjustment Clause	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (Central Gulf Serv Area)	Texas	Weather Normalization Adjustment Clause	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (North Texas Serv Area)	Texas	Weather Normalization Adjustment Clause	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (Rio Grande Valley Serv Area)	Texas	Weather Normalization Adjustment Clause	
Texas Gas Service Company, Inc. (d/b/a ONE Gas) (West Texas Serv Area)	Texas	Weather Normalization Adjustment Clause	
Atmos Energy Corporation (Mid-Tex Division)	Texas	Weather Normalization Adjustment (WNA)	
Atmos Energy Corporation (West Texas Division)	Texas	Weather Normalization Adjustment (WNA) Rider	
Dominion Energy Utah, Inc. (d/b/a Dominion Energy)	Utah	Weather Normalization Adjustment (WNA)	
Vermont Gas Systems, Inc.	Vermont	none	
Columbia Gas of Virginia, Inc. (d/b/a NiSource)	Virginia	Weather Normalization Adjustment (WNA)	2016
Columbia Gas of Virginia, Inc. (d/b/a NiSource)	Virginia	Revenue Normalization Adjustment (RNA)	2019
Roanoke Gas Company	Virginia	Weather Normalization Adjustment (WNA)	2004
Virginia Natural Gas, Inc.	Virginia	Weather Normalization Adjustment (WNA)	
Washington Gas Light Company	Virginia	Weather Normalization Adjustment (WNA)	2007
Atmos Energy Corporation	Virginia	Weather Normalization Adjustment (WNA)	

Company	State	Tariff Available	Year Approved
Avista Corporation	Washington	Decoupling Mechanism	
Cascade Natural Gas Corporation	Washington		
Puget Sound Energy, Inc.	Washington		
Madison Gas & Electric Company	Wisconsin	none	
Northern States Power Company (d/b/a Xcel Energy)	Wisconsin	none	
Wisconsin Electric Power Company	Wisconsin	none	
Wisconsin Gas, LLC	Wisconsin	none	
Wisconsin Power & Light Company (d/b/a Alliant Energy)	Wisconsin	none	
Wisconsin Public Service Corporation	Wisconsin	revenue decoupling mechanism from 2009 to 2013	
Hope Gas, Inc. (d/b/a Dominion Energy)	West Virginia	none	
Mountaineer Gas Company	West Virginia	none	
Black Hills Wyoming Gas, LLC. (d/b/a Black Hills Energy)	Wyoming	Revenue Adjustment Mechanism (RAM)	
Cheyenne Light, Fuel & Power Company (d/b/a Black Hills Energy)	Wyoming	none	
Dominion Energy Wyoming, Inc. (d/b/a Dominion Energy)	Wyoming	Weather Normalization Adjustment (WNA)	
MDU Resources Group, Inc.	Wyoming	none	

BOOK V

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT A – REVENUE REQUIREMENT - FULLY PROJECTED
UGI GAS EXHIBIT A – REVENUE REQUIREMENT - FUTURE
UGI GAS EXHIBIT A – REVENUE REQUIREMENT– HISTORIC
UGI GAS EXHIBIT B – RATE OF RETURN
UGI GAS EXHIBIT E – PROOF OF REVENUE

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 **Effective: March 29, 2022**

UGI GAS

EXHIBIT A – FULLY PROJECTED

Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)
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Fully Projected Future Period - 12 Months Ended September 30, 2023

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SECTION D

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule A-1
Witness: T. A. Hazenstab

Summary of Measure of Value and Revenue Increase

		[1]	[2]	[3]	[4]	[5]
				Pro Forma Test Year Ended September 30, 2023 At		
Line #	Description	Function	Reference Section	Present Rates	Increase	Proposed Rates
	RATE BASE					
1	Utility Plant		C-2	$ 5,042,025		$ 5,042,025
2	Accumulated Depreciation		C-3	(1,318,560)		(1,318,560)
3	Net Plant in service	L 1 + L 2		3,723,465	-	3,723,465
4	Working Capital		C-4	62,148		62,148
5	Gas Inventory		C-5	17,813		17,813
6	Accumulated Deferred Income Taxes		C-6	(628,510)		(628,510)
7	Customer Deposits		C-7	(21,600)		(21,600)
8	Materials & Supplies		C-8	15,707		15,707
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 3,169,023	$ -	$ 3,169,023
	OPERATING REVENUES AND EXPENSES					
	Operating Revenues					
10	Base Customer Charges		D-5	$ 655,274	$ 82,742	$ 738,016
11	Gas Cost Revenue		D-5	397,163		397,163
12	Other Operating Revenues		D-5	10,287		10,287
13	Total Revenues	Sum L 10 to L 12		1,062,724	82,742	1,145,466
14	Operating Expenses		D-1	(828,501)	(1,363)	(829,864)
15	OIBIT	L 13 + L 14		234,223	81,379	315,602
16	Pro Forma Income Tax at Present Rates		D-33	(39,836)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(23,512)	(63,347)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 194,387	$ 57,867	$ 252,255
19	RATE OF RETURN	L 18 / L 9		6.1340%		7.9600%
	REVENUE INCREASE REQUIRED					
20	Rate of Return at Present Rates	L 19, Col 3		6.1340%		
21	Rate of Return Required		B-7	7.9600%		
22	Change in ROR	L 21 - L 20		1.8260%		
23	Change in Operating Income	L 22 * L 9		$ 57,867		
24	Gross Revenue Conversion Factor		D-35	1.429864		
25	Change in Revenues	L 23 * L 24		$ 82,742		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, C 4			12.63%	
27	Percent Increase -- Total Revenues	L 25 / L 13, C 4			7.79%	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-23
	UTILITY PLANT (101 - 106, 108)	
1	Gas Utility Plant	$ 5,042,025
2	Other Utility Plant	
3	Total Plant In Service	5,042,025
4	Construction Work In Progress (107)	70,799
5	Total Utility Plant	5,112,824
6	Accumulated Provision for Depreciation - Gas (108)	(1,318,560)
7	Utility Acquisition Adjustment (114)	182,145
8	Accumulated Provision for Depreciation - Other (119)	
9	Net Utility Plant	3,976,409
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	239
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	1,078
13	Other Investments (124)	68
14	Total Other Property and Investments	1,385
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	5,416
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	85,442
18	Other Accounts Receivable (143)	83
19	Accum Provision for Uncollectible (144)	(10,843)
20	Receivables from Associated Companies (145)	101,296
21	Accounts Receivable Assoc. Comp. (146)	2,818
22	Plant Materials & Operating Supplies (154)	18,328
23	Stores Expense - Undistributed (163)	-
24	Gas Stored - Current (164.1)	35,010
25	Liquefied Natural Gas stored (164.2)	-
26	Prepayments (165)	15,635
27	Accrued Utility Revenues (173)	12,632
28	Miscellaneous Current & Accrued Assets (174)	-
29	Derivative Instrument Assets (175)	8,157
30	Total Current and Accrued Assets	273,974
	DEFERRED DEBITS	
31	Unamortized Debt Expense (181)	4,077
32	Other Regulatory Assets (182.3)	600,319
33	Other Preliminary Survey & Investigation Charges (183.2)	4,267
34	Clearing Accounts (184)	-
35	Miscellaneous Deferred Debits (186)	9,251
36	Unamortized Loss on Reacquired Debt (189)	-
37	Accumulated Deferred Income Taxes (190)	-
38	O/U Collected Gas (191.4, 191.41)	740
39	Total Deferred Debits	618,654
40	TOTAL ASSETS AND OTHER DEBITS	$ 4,870,422

($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-23
	PROPRIETARY CAPITAL	$ 55,318
41	Common Stock Issued (201)	$ -
42	Preferred Stock Issued (204)	583,876
43	Premium on Capital Stock (207)	-
44	Capital Stock Expense (214)	1,166,687
45	Retained Earnings (215, 215.2, 216)	(20,455)
46	Accum Other Comprehensive Income (219)	
47	Total Proprietary Capital	1,785,426
	LONG TERM DEBT	
48	Bonds (221)	-
49	Advances from Associated Companies (223)	-
50	Other Long-Term Debt (224)	1,339,945
51	Unamortized Premium on LTD (225)	-
52	Unamortized Discount on LTD (226)	-
53	Total Long-term Debt	1,339,945
	OTHER NON-CURRENT LIABILITIES	
54	Obligations under Capital Leases (227)	-
55	Accum. Prov for Injuries & Damages (228.2)	1,870
56	Accum. Prov for Pensions & Benefits (228.3)	116,192
57	Accum. Miscellaneous Operating Prov (228.4)	42,703
58	Asset Retirement Obligation (230)	-
59	Total Non-Current Liabilities	160,765
	CURRENT & ACCRUED LIABILITIES	
60	Notes Payable (231)	212,905
61	Accounts Payable (232)	79,169
62	Notes Payable to Assoc. Companies (233)	111,794
63	Accounts Payable to Assoc. Cos (234)	15,381
64	Customer Deposits (235)	33,241
65	Taxes Accrued (236)	826
66	Interest Accrued (237)	11,581
67	Tax Collections Payable (241)	-
68	Accrued Interest on Other Liabilities (237)	51,417
69	Tax Collections Payable (241)	3,463
70	Misc Current & Accrued Liabilities (242)	-
71	Total Current & Accrued Liabilities	519,777
	OTHER DEFERRED CREDITS	
72	Customer Advances for Construction (252)	12,303
73	Other Deferred Credits (253)	291,869
74	Other Regulatory Liabilities (254)	943
75	Deferred ITC (255)	719,188
76	Accumulated Deferred Income Taxes (282)	40,206
77	Accumulated Deferred Income Taxes (283)	
78	Total Other Deferred Credits	1,064,509
79	TOTAL LIABILITIES & OTHER CREDITS	$ 4,870,422

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Statement of Net Utility Operating Income

Line No	Description	[1] Budget TYE 9-30-23	[2] Reference
	Total Operating Revenues		
1	Total Sales Revenues	$ 986,747	B-3
2	Other Operating Revenues	9,939	B-3
3	Total Revenues	996,686	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	625,766	B-4 & D-2
5	Depreciation & Amortization Expense	128,358	D-2
6	Taxes Other Than Income Taxes	13,360	B-5
7	Total Operating Expenses	767,484	
8	Operating Income Before Income Taxes (OIBIT)	229,202	
	Income Taxes:		
9	State	7,394	B-5
10	Federal	32,442	B-5
11	Total Income Taxes	39,836	
12	**Net Utility Operating Income**	$ 189,366	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Statement of Operating Revenues

Line No	Description	[1] Budget TYE 9-30-23
	Gas Operating Revenues	
1	Residential (R/RT) (480)	$ 621,416
2	Comm & Ind (N/NT) (481)	230,372
3	Comm & Ind (DS) (489)	32,197
4	Lg Transport/Other (489)	79,760
5	Interruptible (489)	23,002
6	Sub-Total Gas Operating Revenues	986,747
	Other Operating Revenues	
7	Forfeited Discounts (487)	5,603
8	Miscellaneous Service Revenues (488)	923
9	Rent from Gas Properties (493)	2,338
10	Other Revenues (495)	1,075
11	Sub-Total Other Operating Revenues	9,939
12	**Total Operating Revenues**	$ 996,686

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-23
	Gas Raw Materials		
1	Liquefied Petroleum Gas Expenses	717	$ -
2	Miscellaneous Production Expenses	735	14
3	Total Gas Raw Materials Expenses		14
	Production and Gathering - Operations		
4	Operating Supervision and Engineering	750	-
5	Production Maps and Records	751	-
6	Gas Wells Expenses	752	-
7	Field Lines Expenses	753	-
8	Gas Well Royalties	758	-
9	Other Expenses	759	-
10	Total Production & Gathering Operation Expenses		-
	Production and Gathering - Maintenance		
11	Maintenance of Producing Gas Wells	763	-
12	Maintenance of Field Lines	764	-
13	Maintenance of Field Measuring and Reg. Station Equip.	766	-
14	Gas Supply Operation Expenses		-
	Other Gas Supply Expense - Operations		
15	Natural Gas City Gate Purchases	804.0	371,499
16	Other Gas Purchases	805.0	82
17	Purchases Gas Cost Adjustments	805.1	(16,942)
18	Gas Withdrawn from Storage-Debit	808.1	31,278
19	Purchased Gas Expenses	807.0	-
20	Gas Used for Other Utility Operations-Credit	812.0	-
21	Gas Delivered to Storage-Credit	808.2	(27,988)
22	Other Gas Supply Expenses	813.0	357
23	Gas Supply Operation Expenses		358,286
	Underground Storage Expense - Operation		
24	Operation Supervision and Engineering	814	-
25	Maps and Records	815	-
26	Wells Expenses	816	-
27	Lines Expenses	817	-
28	Measuring and Regulating Station Expenses	820	-
29	Purification Expenses	821	-
30	Gas Losses	823	-
31	Other Expenses	824	-
32	Total Underground Storage Expenses		-
	Underground Storage Expense - Maintenance		
33	Maintenance Supervision and Engineering	830	-
34	Maintenance of Structures and Improvements	831	-
35	Maintenance of Reservoirs and Wells	832	-
36	Maintenance of Lines	833	-
37	Maintenance of Measuring & Regulating Station Equip.	835	-
38	Total Underground Maintenance Expenses		-

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-23
	Transmission Expense - Operations		
39	Operating Supervision and Engineering	850	-
40	System Control and Load Dispatching	851	-
41	Communication System Expenses	852	-
42	Mains Expenses	856	-
43	Measuring and Regulating Station Expenses	857	-
44	Other Expenses	859	-
45	Total Transmission Operation Expenses		-
	Transmission Expense - Maintenance		
46	Maintenance Supervision and Engineering	861	-
47	Maintenance of Structures and Improvements	862	-
48	Maintenance of Mains	863	-
49	Maintenance of Measuring and Regulating Station Equip.	865	-
50	Maintenance of Communication Equipment	866	-
51	Total Transmission Maintenance Expenses		-
	Distribution Expense - Operations		
52	Operation Supervision and Engineering	870	3,415
53	Distribution Load Dispatching	871	2
54	Compressor Station Fuel and Power (Major Only)	873	-
55	Mains and Services Expenses	874	27,345
56	Measuring and Regulating Station Expenses-General	875	4,188
57	Measuring and Regulating Station Expenses-Industrial	876	12
58	Measuring and Regulating Station Expenses-City Gate	877	114
59	Meter and House Regulator Expenses	878	3,204
60	Customer Installations Expenses	879	2,721
61	Other Expenses	880	1,281
62	Rents	881	3,117
63	Total Distribution Operation Expenses		45,399
	Distribution Expense - Maintenance		
64	Maintenance Supervision and Engineering	885	509
65	Maintenance of Structures and Improvements	886	-
66	Maintenance of Mains	887	28,149
67	Maintenance of Compressor Station Equipment	888	262
68	Maintenance of Measuring & Reg. Station Equip.-Genl.	889	3,144
69	Maintenance of Measuring & Reg. Station Equip.-Indtrl.	890	4,686
70	Maintenance of Measuring & Reg. Station Equip.-City G	891	121
71	Maintenance of Services	892	1,547
72	Maintenance of Meters & House Regulators	893	-
73	Maintenance of Other Equipment	894	552
74	Construction & Maintenance	895	-
75	Total Distribution Maintenance Expenses		38,970
	Customer Accounts Expense - Operations		
76	Supervision	901	824
77	Meter Reading Expenses	902	2,177
78	Customer Records & Collection Expenses	903	35,342
79	Uncollectable Accounts	904	14,419
80	Miscellaneous Customer Accounts Expenses	905	2,198
81	Total Administrative & General		54,960

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-23
	Customer Service & Information Expense		
82	Supervision	907	172
83	Customer Assistance Expenses	908	896
84	Informational & Instructional Advertising Expenses	909	-
85	Miscellaneous Customer Service & Informational Exp.	910	9,300
86	Total Cust. Service & Inform. Operations Exp		10,368
87	Description		
	Sales Expense		
88	Supervision	911	426
89	Demonstrating and Selling Expenses	912	(596)
90	Advertising Expenses	913	1,637
91	Miscellaneous Sales Expenses	916	258
92	Total Operation Sales Expenses		1,725
	Administrative & General - Operations		
93	Administrative and General Salaries	920.0	35,612
94	Office Supplies and Expenses	921.0	21,222
95	Outside Service Employed	923.0	25,611
96	Property Insurance	924.0	-
97	Injuries and Damages	925.0	11,027
98	Employee Pensions and Benefits	926.0	13,723
99	Regulatory Commission Expenses	928.0	1,138
100	General Advertising Expenses	930.1	288
101	Miscellaneous General Expenses	930.2	2,728
102	Rents	931.0	38
103	Total A & G Operation Expenses		111,387
	Administrative & General - Maintenance		
104	A&G Maintenance of General Plant	932	4,394
105	A&G Maintenance of General Plant	935	263
106	Total A & G Maintenance Expenses		4,657
107	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 625,766
108	Total Gas Operation Expenses		582,139
109	Total Gas Maintenance Expense		43,627
110	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 625,766

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Detail of Taxes

Line No	Description	Reference	[1] Budget TYE 9-30-23
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 822
2	Capital Stock	D-31	-
3	PA and Local Use taxes	D-31	1,868
4	PUC Assessment	D-31	4,042
5	Subtotal		6,732
	Payroll Taxes		
6	FICA	D-31	6,023
7	SUTA	D-31	493
8	FUTA	D-31	113
9	Other		-
10	Subtotal		6,628
11	Total Taxes Other Than Income Taxes		$ 13,360
	Income Taxes		
12	State		$ 7,394
13	Federal		32,442
14	Total Income Taxes		$ 39,836

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule B-6
Witness: P. R. Moul
Page 1 of 1

Composite Cost of Debt

Line No	Description		[1] Amount Outstanding	[2] Percent to Total	[3] Effective Interest Rate	[4] Average Weighted Cost Rate [2] * [3]
	Medium Term Notes					
1	6.500% Due 8/15/2033	$	20,000	1.35%	6.56%	0.09%
2	6.133% Due 10/15/2034		20,000	1.35%	6.19%	0.08%
	Senior Unsecured Notes					
3	6.206% Due 9/30/2036		100,000	6.74%	6.32%	0.43%
4	4.980% Due 3/26/2044		175,000	11.79%	5.00%	0.59%
5	2.950% Due 6/30/2026		100,000	6.74%	3.92%	0.26%
6	4.120% Due 9/30/2046		200,000	13.48%	5.01%	0.68%
7	4.120% Due 10/31/2046		100,000	6.74%	4.28%	0.29%
8	3.120% Due 4/16/2050		150,000	10.11%	3.15%	0.32%
9	4.550% Due 02/01/2049		150,000	10.11%	4.58%	0.46%
10	1.590% Due 6/15/2026		100,000	6.74%	1.73%	0.12%
11	1.640% Due 9/15/2026		75,000	5.05%	1.75%	0.09%
12	3.687% Due 5/31/2052		90,000	6.07%	3.71%	0.23%
13	1.410% Due 7/31/2027		118,750	8.00%	1.53%	0.12%
14	3.791% Due 10/31/2052		85,000	5.73%	3.82%	0.22%
15	Total Long-Term Debt	$	1,483,750	100.00%		3.98%
16	Total Long-Term Debt	$	1,483,750	100.00%	3.98%	3.98%
17	Total Short-Term Debt			0.00%		0.00%
18	TOTAL	$	1,483,750	100.00%		
19	Weighted Cost of Debt					3.98%

($ in Thousands)

Rate of Return

		[1]	[2]	[3]	[4]
Line No	**Description**	**Capitalization Ratio**	**Embedded Cost**	**Statement Reference**	**Return-%**
1	Long-Term Debt	44.91%	3.98%	B-6	1.79%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	55.09%	11.20%		6.17%
4	Total	100.00%			7.96%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule C-1
Witness: V. K. Ressler
Page 1 of 1

Measure of Value

		[1]	[2]	[3]	[4]	[5]
Line		Reference		Pro Forma Test Year Ended September 30, 2023 At		
#	Description	Schedule	# of Pages	Present Rates	Adjustments	Proposed Rates
MEASURE OF VALUE						
1	Utility Plant	C-2	9	$ 5,042,025		$ 5,042,025
2	Accumulated Depreciation	C-3	11	(1,318,560)		(1,318,560)
3	Net Plant in service			3,723,465	-	3,723,465
4	Working Capital	C-4	9	62,148		62,148
5	Gas Inventory	C-5	1	17,813		17,813
6	Accumulated Deferred Income Taxes	C-6	1	(628,510)		(628,510)
7	Customer Deposits	C-7	1	(21,600)		(21,600)
8	Materials & Supplies	C-8	1	15,707		15,707
9	TOTAL MEASURE OF VALUE			$ 3,169,023	$ -	$ 3,169,023

($ in Thousands)

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma FTY 9-30-23
	INTANGIBLE PLANT		
1	Organization	301	$ 290
2	Franchise & Consent	302	194
3	Miscellaneous Intangible Plant	303	290
4	TOTAL INTANGIBLE		774
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	13
6	Producing Leaseholds	325	163
7	Rights of Way	325	30
8	Other Land Rights	326	1
9	Field Measuring & Regulating Station Structures	328	1
10	Other Structures	329	45
11	Producing Gas Wells-Well Construction	330	18
12	Producing Gas Wells-Well Equipment	331	24
13	Field Lines	332	751
14	Field Measuring & Reg. Station Equipment	334	90
15	Drilling & Cleaning Equipment	335	50
16	Other Equipment	337	11
17	TOTAL PRODUCTION & GATHERING		1,197
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	382
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		382

($ in Thousands)

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma FTY 9-30-23
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	$ 47
31	Rights of Way	365.2	868
32	Structures & Improvements	366	162
33	Mains	367	39,075
34	Measuring & Regulating Station Equipment	369	6,152
35	Communication Equipment	370	3,486
36	Other Equipment	371	351
37	TOTAL TRANSMISSION		50,141
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	11,700
39	Structures & Improvements	375	5,554
40	Mains	376	2,395,421
41	Measuring & Regulating Station Equipment	378	189,363
42	Measuring & Regulating Station Equipment	379	25,636
43	Services	380	1,452,368
44	Meters	381	184,281
45	Meter Installations	382	108,483
46	House Regulators	383	10,726
47	House Regulatory Installations	384	18,954
48	Industrial Measuring & Reg. Station Equipment	385	39,907
49	Other Property	386	1,046
50	Other Equipment	387	6,362
51	TOTAL DISTRIBUTION		4,449,801
	GENERAL PLANT		
52	Land & Land Rights	389	16,552
53	Structures & Improvements	390	164,766
54	Office Furniture & Equipment	391	256,309
55	Transportation Equipment	392	51,602
56	Stores Equipment	393	18
57	Tools & Garage Equipment	394	40,200
58	Laboratory Equipment	395	438
59	Power Operated Equipment	396	6,571
60	Communication Equipment	397	907
61	Miscellaneous Equipment	398	2,367
62	Other Tangible Property	399	-
63	TOTAL GENERAL		539,730
64	Total Plant		$ 5,042,025

($ in Thousands)

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Test Year 9/30/23 Budget	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Pg 4	$ 774	$ -	$ 774
2	Natural Gas Production & Gathering	Sch C-2, Pg 4	1,197	-	1,197
3	Natural Gas Storage & Processing Plant	Sch C-2, Pg 4	382	-	382
4	Transmission Plant	Sch C-2, Page 5	50,141	-	50,141
5	Distribution Plant	Sch C-2, Page 5	4,449,801	-	4,449,801
6	General Plant	Sch C-2, Page 5	539,730	-	539,730
7	Other Plant		-	-	-
8	Total Utility Plant		$ 5,042,025	$ -	$ 5,042,025

($ in Thousands)

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2022	[3] 2023	[4] Pro Forma Adjustment	[5] Balance
INTANGIBLE PLANT						
1	Organization	301	$ 290	$ 290	$ -	$ 290
2	Franchise & Consent	302	194	194	-	194
3	Miscellaneous Intangible Plant	303	290	290	-	290
4	TOTAL INTANGIBLE		774	774	-	774
NATURAL GAS PRODUCTION & GATHERING						
5	Producing Lands	325.1	13	13	-	13
6	Producing Leaseholds	325.2	163	163	-	163
7	Rights of Way	325.4	30	30	-	30
8	Other Land Rights	325.5	1	1	-	1
9	Field Measuring & Regulating Station Structures	328	1	1	-	1
10	Other Structures	329	45	45	-	45
11	Producing Gas Wells-Well Construction	330	18	18	-	18
12	Producing Gas Wells-Well Equipment	331	24	24	-	24
13	Field Lines	332	751	751	-	751
14	Field Measuring & Reg. Station Equipment	334	90	90	-	90
15	Drilling & Cleaning Equipment	335	50	50	-	50
16	Other Equipment	337	11	11	-	11
17	TOTAL PRODUCTION & GATHERING		1,197	1,197	-	1,197
NATURAL GAS STORAGE & PROCESSING PLANT						
18	Land & Land Rights	304	382	382	-	382
19	Production Plant-Manufactured Gas Plants	305	-	-	-	-
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	-	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	-	-	-	-
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		382	382	-	382

($ in Thousands)

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2022	[3] 2023	[4] Pro Forma Adjustment	[5] Balance
	TRANSMISSION PLANT					
30	Land & Land Rights	365.1	47	47	-	47
31	Rights of Way	365.2	868	868	-	868
32	Structures & Improvements	366	162	162	-	162
33	Mains	367	39,075	39,075	-	39,075
34	Measuring & Regulating Station Equipment	369	6,152	6,152	-	6,152
35	Communication Equipment	370	3,486	3,486	-	3,486
36	Other Equipment	371	351	351	-	351
37	TOTAL TRANSMISSION		50,141	50,141	-	50,141
	DISTRIBUTION PLANT					
38	Land & Land Rights	374	11,700	11,700	-	11,700
39	Structures & Improvements	375	5,554	5,554	-	5,554
40	Mains	376	2,148,395	2,395,421	-	2,395,421
41	Measuring & Regulating Station Equipment	378	157,825	189,363	-	189,363
42	Measuring & Regulating Station Equipment	379	25,636	25,636	-	25,636
43	Services	380	1,386,389	1,452,368	-	1,452,368
44	Meters	381	175,939	184,281	-	184,281
45	Meter Installations	382	103,617	108,483	-	108,483
46	House Regulators	383	10,666	10,726	-	10,726
47	House Regulatory Installations	384	18,728	18,954	-	18,954
48	Industrial Measuring & Reg. Station Equipment	385	39,907	39,907	-	39,907
49	Other Property	386	1,046	1,046	-	1,046
50	Other Equipment	387	6,362	6,362	-	6,362
51	TOTAL DISTRIBUTION		4,091,764	4,449,801	-	4,449,801
	GENERAL PLANT					
52	Land & Land Rights	389	16,552	16,552	-	16,552
53	Structures & Improvements	390	141,083	164,766	-	164,766
54	Office Furniture & Equipment	391	205,177	256,309	-	256,309
55	Transportation Equipment	392	42,474	51,602	-	51,602
56	Stores Equipment	393	18	18	-	18
57	Tools & Garage Equipment	394	37,479	40,200	-	40,200
58	Laboratory Equipment	395	438	438	-	438
59	Power Operated Equipment	396	6,571	6,571	-	6,571
60	Communication Equipment	397	939	907	-	907
61	Miscellaneous Equipment	398	2,415	2,367	-	2,367
62	Other Tangible Property	399	-	-	-	-
63	TOTAL GENERAL		453,146	539,730	-	539,730
64	Total Plant		$ 4,597,404	$ 5,042,025	$ -	$ 5,042,025

($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2022	[3] 2023
	Plant Additions			
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2022	[3] 2023
	TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	226,479	253,897
41	Measuring & Regulating Station Equipment	378	42,309	34,216
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	72,015	73,001
44	Meters	381	11,057	9,876
45	Meter Installations	382	5,836	5,384
46	House Regulators	383	66	66
47	House Regulatory Installations	384	250	250
48	Industrial Measuring & Reg. Station Equipment	385	-	-
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		358,012	376,690
	GENERAL PLANT			
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	9,480	25,340
54	Office Furniture & Equipment	391	14,239	60,029
55	Transportation Equipment	392	12,022	11,206
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	4,473	3,367
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	178	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		40,392	99,942
64	Total Plant		$ 398,404	$ 476,632

($ in Thousands)

Retirements

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2022	2023
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

($ in Thousands)

Retirements

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2022	2023
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	6,206	6,872
41	Measuring & Regulating Station Equipment	378	3,312	2,678
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	6,927	7,022
44	Meters	381	1,718	1,534
45	Meter Installations	382	561	518
46	House Regulators	383	6	6
47	House Regulatory Installations	384	24	24
48	Industrial Measuring & Reg. Station Equipment	385	-	-
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		18,754	18,654
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	654	1,660
54	Office Furniture & Equipment	391	25,464	8,893
55	Transportation Equipment	392	2,229	2,078
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	684	646
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	83	32
61	Miscellaneous Equipment	398	144	48
62	Other Tangible Property	399	16	-
63	TOTAL GENERAL		29,274	13,357
64	Total Plant		$ 48,028	$ 32,011

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Schedule C-3
Witness: V. K. Ressler
Page 1 of 11

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma FTY 9-30-23
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	162
7	Rights of Way	325	30
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	1
10	Other Structures	329	45
11	Producing Gas Wells-Well Construction	330	18
12	Producing Gas Wells-Well Equipment	331	24
13	Field Lines	332	727
14	Field Measuring & Reg. Station Equipment	334	85
15	Drilling & Cleaning Equipment	335	50
16	Other Equipment	337	11
17	TOTAL PRODUCTION & GATHERING		1,153
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	69
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	(36)
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		33

($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma FTY 9-30-23
	TRANSMISSION PLANT		
30	Land & Land Rights	365	-
31	Rights of Way	365	548
32	Structures & Improvements	366	148
33	Mains	367	22,346
34	Measuring & Regulating Station Equipment	369	4,059
35	Communication Equipment	370	2,244
36	Other Equipment	371	288
37	TOTAL TRANSMISSION		29,633
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	1,427
39	Structures & Improvements	375	3,343
40	Mains	376	506,998
41	Measuring & Regulating Station Equipment	378	28,861
42	Measuring & Regulating Station Equipment	379	9,033
43	Services	380	425,137
44	Meters	381	78,565
45	Meter Installations	382	38,253
46	House Regulators	383	7,113
47	House Regulatory Installations	384	9,351
48	Industrial Measuring & Reg. Station Equipment	385	18,367
49	Other Property	386	619
50	Other Equipment	387	4,508
51	TOTAL DISTRIBUTION		1,131,575
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	46,457
54	Office Furniture & Equipment	391	76,330
55	Transportation Equipment	392	14,486
56	Stores Equipment	393	7
57	Tools & Garage Equipment	394	14,191
58	Laboratory Equipment	395	134
59	Power Operated Equipment	396	2,888
60	Communication Equipment	397	479
61	Miscellaneous Equipment	398	1,194
62	Other Tangible Property	399	
63	TOTAL GENERAL		156,166
64	Total Plant		$ 1,318,560

($ in Thousands)

Summary of Accumulated Depreciation

		[1]	[2]	[3]	[4]
			Test Year Ended September 30, 2023		
Line #	Description	Factor Or Reference	Amount	Pro Forma Adjustment	Balance
1	Intangible Plant	Sch C-3, Pg 4	$ -	$ -	$ -
2	Natural Gas Production & Gathering	Sch C-3, Pg 4	1,153	-	1,153
3	Natural Gas Storage & Processing Plant	Sch C-3, Pg 4	33	-	33
4	Transmission Plant	Sch C-3, Pg 5	29,633	-	29,633
5	Distribution Plant	Sch C-3, Pg 5	1,131,575	-	1,131,575
6	General Plant	Sch C-3, Pg 5	156,166	-	156,166
7	Other Plant		-	-	-
8	TOTAL ACC DEPR & AMORTIZATION		$ 1,318,560	$ -	$ 1,318,560

($ in Thousands)

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2022	[3] Year Ended September 30, 2023	[4] Pro Forma Adjustment	[5] Balance
	INTANGIBLE PLANT					
1	Organization	301	$ -	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-	-
4	TOTAL INTANGIBLE		-	-	-	-
	NATURAL GAS PRODUCTION & GATHERING					
5	Producing Lands	325.1	-	-	-	-
6	Producing Leaseholds	325.2	162	162	-	162
7	Rights of Way	325.4	30	30	-	30
8	Other Land Rights	325.5	-	-	-	-
9	Field Measuring & Regulating Station Structures	328	1	1	-	1
10	Other Structures	329	45	45	-	45
11	Producing Gas Wells-Well Construction	330	18	18	-	18
12	Producing Gas Wells-Well Equipment	331	24	24	-	24
13	Field Lines	332	726	727	-	727
14	Field Measuring & Reg. Station Equipment	334	85	85	-	85
15	Drilling & Cleaning Equipment	335	50	50	-	50
16	Other Equipment	337	11	11	-	11
17	TOTAL PRODUCTION & GATHERING		1,152	1,153	-	1,153
	NATURAL GAS STORAGE & PROCESSING PLANT					
18	Land & Land Rights	304	-	-	-	-
19	Production Plant-Manufactured Gas Plants	305	92	69	-	69
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	-	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	(36)	(36)	-	(36)
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		56	33	-	33

($ in Thousands)

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2022	[3] 2023	[4] Pro Forma Adjustment	[5] Balance
	TRANSMISSION PLANT					
30	Land & Land Rights	365.1	-	-	-	-
31	Rights of Way	365.2	537	548	-	548
32	Structures & Improvements	366	146	148	-	148
33	Mains	367	21,888	22,346	-	22,346
34	Measuring & Regulating Station Equipment	369	3,966	4,059	-	4,059
35	Communication Equipment	370	2,141	2,244	-	2,244
36	Other Equipment	371	282	288	-	288
37	TOTAL TRANSMISSION		28,960	29,633	-	29,633
	DISTRIBUTION PLANT					
38	Land & Land Rights	374	1,381	1,427	-	1,427
39	Structures & Improvements	375	3,256	3,343	-	3,343
40	Mains	376	477,478	506,998	-	506,998
41	Measuring & Regulating Station Equipment	378	26,619	28,861	-	28,861
42	Measuring & Regulating Station Equipment	379	8,409	9,033	-	9,033
43	Services	380	396,104	425,137	-	425,137
44	Meters	381	74,577	78,565	-	78,565
45	Meter Installations	382	36,059	38,253	-	38,253
46	House Regulators	383	6,699	7,113	-	7,113
47	House Regulatory Installations	384	8,897	9,351	-	9,351
48	Industrial Measuring & Reg. Station Equipment	385	17,515	18,367	-	18,367
49	Other Property	386	594	619	-	619
50	Other Equipment	387	4,401	4,508	-	4,508
51	TOTAL DISTRIBUTION		1,061,989	1,131,575	-	1,131,575
	GENERAL PLANT					
52	Land & Land Rights	389	-	-	-	-
53	Structures & Improvements	390	43,604	46,457	-	46,457
54	Office Furniture & Equipment	391	65,625	76,330	-	76,330
55	Transportation Equipment	392	11,359	14,486	-	14,486
56	Stores Equipment	393	6	7	-	7
57	Tools & Garage Equipment	394	12,824	14,191	-	14,191
58	Laboratory Equipment	395	112	134	-	134
59	Power Operated Equipment	396	2,417	2,888	-	2,888
60	Communication Equipment	397	402	479	-	479
61	Miscellaneous Equipment	398	893	1,194	-	1,194
62	Other Tangible Property	399	-	-	-	-
63	TOTAL GENERAL		137,242	156,166	-	156,166
64	Total Plant		$ 1,229,399	$ 1,318,560	$ -	$ 1,318,560

($ in Thousands)

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2022	[3] 2023
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330		
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305		
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

($ in Thousands)

Cost of Removal

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2022	2023
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	2,022	2,145
41	Measuring & Regulating Station Equipment	378	657	531
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	3,575	3,624
44	Meters	381	1	1
45	Meter Installations	382	290	267
46	House Regulators	383	3	3
47	House Regulatory Installations	384	12	12
48	Industrial Measuring & Reg. Station Equipment	385	-	-
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		6,560	6,583
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	66	166
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	-	-
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	-	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		66	166
64	Total Plant		$ 6,626	$ 6,749

($ in Thousands)

Negative Net Salvage Amortization

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2022	2023
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	(23)	(23)
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		(23)	(23)

($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2022	[3] 2023
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	1	1
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		1	1
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	1,606	1,629
41	Measuring & Regulating Station Equipment	378	172	218
42	Measuring & Regulating Station Equipment	379	3	3
43	Services	380	4,364	3,945
44	Meters	381	(3)	(4)
45	Meter Installations	382	450	438
46	House Regulators	383	262	(9)
47	House Regulatory Installations	384	108	111
48	Industrial Measuring & Reg. Station Equipment	385	13	8
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		6,975	6,339
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	32	65
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(340)	(428)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	131	130
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(177)	(233)
64	Total Plant		$ 6,776	$ 6,084

($ in Thousands)

Salvage

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2022	2023
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

($ in Thousands)

Salvage

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2022	2023
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	-	-
41	Measuring & Regulating Station Equipment	378	(219)	(177)
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	-	-
44	Meters	381	(4)	(4)
45	Meter Installations	382	-	-
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	-	-
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		(223)	(181)
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	-	-
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(478)	(445)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	-	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(478)	(445)
64	Total Plant		$ (701)	$ (626)

Working Capital

		[1]	[2]
Line No	**Description**	**Fully Projected FTY 9-30-23**	**Reference**
1	Working Capital for O & M Expense	$ 52,365	C-4, Page 2
2	Interest Payments	(4,667)	C-4, Page 7
3	Tax Payment Lag Calculations	4,402	C-4, Page 8
4	Prepaid Expenses	10,047	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 62,148	

($ in Thousands)

Summary of Working Capital

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Reference	Test Year Expenses	Factor	Number of (Lead) / Lag Days [2] * [3]	Totals
	WORKING CAPITAL REQUIREMENT					
1	REVENUE LAG DAYS	Page 3				61.18
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 82,929	12.00	$ 995,146	
4	Purchased Gas Costs	Sch D-6	397,163	39.85	15,828,733	
5	Other Expenses	L 19 - L 2 to L 4	192,619	27.08	5,216,116	
6	Total	Sum (L 3 to L 5)	$ 672,711		$ 22,039,994	
7	O & M Expense Lag Days	L6, C 4 / C 2				32.76
8	Net (Lead) Lag Days	L 1 - L 7				28.41
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 1,843
10	Working Capital for O & M Expense	L 8 * L 9				$ 52,365
11	Interest Payments	Page 7				(4,667)
12	Tax Payment Lag Calculations	Page 8				4,402
13	Prepaid Expenses	Page 9				10,047
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 62,148
15	Pro Forma O & M Expense		$ 689,306			
	Less:					
16	Uncollectible Expense		16,595			
17	Sub-Total		16,595			
18	Pro Forma Cash O&M Expense		$ 672,711			

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month	[3] Total Monthly Sales Page 2	[4] A/R Turnover [3] / [2]		[5] Days Lag 365 / [4]
1	Annual Number of Days						365
2	September, 2020		$ 52,950				
3	October		$ 61,679	$ 41,665			
4	November		$ 72,123	$ 55,297			
5	December, 2020		$ 106,368	$ 100,676			
6	January, 2021		$ 140,439	$ 126,612			
7	February		$ 164,061	$ 130,900			
8	March		$ 153,427	$ 128,921			
9	April		$ 133,479	$ 74,513			
10	May		$ 116,982	$ 48,952			
11	June		$ 100,284	$ 39,572			
12	July		$ 87,161	$ 31,323			
13	August		$ 76,062	$ 33,489			
14	September, 2021		$ 62,224	$ 32,352			
15	Total	Sum L 2 to L 14	$1,327,239				
16	Number of Months	13					
17	Average Acct Rec Balance	L 15 / L 16	$102,095				
18	Total Sales for Year	Sum L 2 to L 14		$ 844,272			
19	Acct Rec Turnover Ratio	L 18 / L 17			8.27		
20	Collection Lag Day Factor	L 1 / L 19					44.14
21	Meter Read Lag Factor						1.83
22	Midpoint Lag Factor		365 /	12 /	2	=	15.21
23	Total Revenue Lag Days	Sum L 20 to L 22					**61.18**

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
PAYROLL						
1	Union Payrolls	Bi-Weekly	$ 32,381	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	50,548	12.00		
3	Weighted for Union	L1, C2 * C3			$ 388,572	
4	Weighted for Other	L2, C2 * C3			606,571	
5	Payroll Lag	L 3 + L 4	$ 82,929		$ 995,144	
6	Payroll Lag Days	C 4 / C 2				12.00
PURCHASE GAS COSTS						
7	Payment Lag	Page 6	$ 374,258		$ 14,915,898	
8	Gas Cost Lag Days	C 4 / C 2				39.85
OTHER O & M EXPENSES						
9	OCTOBER 2020	Page 5	$ 13,011		$ 464,688	
10	NOVEMBER 2020	Page 5	12,267		354,754	
11	DECEMBER 2020	Page 5	10,704		296,691	
12	JANUARY 2021	Page 5	13,154		403,634	
13	FEBRUARY 2021	Page 5	9,535		296,050	
14	MARCH 2021	Page 5	15,795		392,990	
15	APRIL 2021	Page 5	8,487		212,723	
16	MAY 2021	Page 5	11,246		236,159	
17	JUNE 2021	Page 5	13,342		293,544	
18	JULY 2021	Page 5	10,212		305,230	
19	AUGUST 2021	Page 5	11,697		290,457	
20	SEPTEMBER 2021	Page 5	13,828		332,536	
21	TOTAL		$ 143,277		$ 3,879,457	
22	Other O&M Expense Lag Days	L21, C 4 / C 2				27.08

($ in Thousands)

General Disbursements Payment Lag Summary

		[1]	[2]	[3]	[4]
Line #	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag-Days [3] / [2]
OCTOBER 2020					
1	Total Disbursements for Month	32,992	$ 57,092		
2	Total Disbursements for Expenses	5,068	$ 13,011	$ 464,688	35.72
NOVEMBER 2020					
3	Total Disbursements for Month	21,713	$ 41,983		
4	Total Disbursements for Expenses	4,909	$ 12,267	$ 354,754	28.92
DECEMBER 2020					
5	Total Disbursements for Month	21,745	$ 31,881		
6	Total Disbursements for Expenses	4,741	$ 10,704	$ 296,691	27.72
JANUARY 2021					
7	Total Disbursements for Month	22,708	$ 37,776		
8	Total Disbursements for Expenses	4,488	$ 13,154	$ 403,634	30.68
FEBRUARY 2021					
9	Total Disbursements for Month	19,680	$ 29,480		
10	Total Disbursements for Expenses	4,120	$ 9,535	$ 296,050	31.05
MARCH 2021					
11	Total Disbursements for Month	16,472	$ 34,931		
12	Total Disbursements for Expenses	4,961	$ 15,795	$ 392,990	24.88
APRIL 2021					
13	Total Disbursements for Month	25,582	$ 30,669		
14	Total Disbursements for Expenses	4,614	$ 8,487	$ 212,723	25.06
MAY 2021					
15	Total Disbursements for Month	28,733	$ 34,180		
16	Total Disbursements for Expenses	4,800	$ 11,246	$ 236,159	21.00
JUNE 2021					
17	Total Disbursements for Month	33,951	$ 49,835		
18	Total Disbursements for Expenses	5,546	$ 13,342	$ 293,544	22.00
JULY 2021					
19	Total Disbursements for Month	31,356	$ 42,313		
20	Total Disbursements for Expenses	5,502	$ 10,212	$ 305,230	29.89
AUGUST 2021					
21	Total Disbursements for Month	30,804	$ 37,118		
22	Total Disbursements for Expenses	5,756	$ 11,697	$ 290,457	24.83
SEPTEMBER 2021					
23	Total Disbursements for Month	36,824	$ 55,311		
24	Total Disbursements for Expenses	5,645	$ 13,828	$ 332,536	24.05
25	Total Test Month Expense Disbursement	60,150	$ 143,277	$ 3,879,457	27.08

Purchase Gas Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	October 2020	28	$ 11,709	$ 418,248	35.72
2	November	38	35,682	1,031,745	28.92
3	December	28	30,793	1,407,814	45.72
4	January 2021	38	54,079	2,588,442	47.86
5	February	34	53,409	2,165,844	40.55
6	March	28	52,465	2,037,549	38.84
7	April	27	24,904	1,006,441	40.41
8	May	37	23,869	887,286	37.17
9	June	28	19,244	729,594	37.91
10	July	27	19,573	757,275	38.69
11	August	27	23,147	911,332	39.37
12	Septermber 2021	28	25,384	974,330	38.38
13	Total		$ 374,258	$ 14,915,898	
14	Purchase Gas Lag Days				39.85

Interest Payments

		[1]	[2]	[3]	[4]
Line No.	Description	Reference Or Factor	# of Days	# of Days	Total
1	Measure of Value at September 30, 2023	Sch C-1			$ 3,169,023
2	Long-term Debt Ratio	Sch B-6			44.91%
3	Embedded Cost of Long-term Debt	Sch B-6			3.98%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 56,644
5	Daily Amount	L 4 / L 5 [2]	365		$ 155
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		61.18	
8	Interest Payment lag days	L 7 - L 6			(30.1)
9	Total Interest for Working Capital	L 5 * L 8			$ (4,667)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars	[6] Payment Lead (Lag) Days	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days	[9] Total Dollar Days	[10] Working Capital Amount
				[1] - [2]		[3] * [4]	[5] / [4]		[6] - [7]		
											365
1	**FEDERAL INCOME TAX**				$ 47,824						
2	First Payment	01/15/23	04/01/23	76.00	$ 11,956	908,658					
3	Second Payment	03/15/23	04/01/23	17.00	11,956	203,252					
4	Third Payment	06/15/23	04/01/23	(75.00)	11,956	(896,702)					
5	Fourth Payment	09/15/23	04/01/23	(167.00)	11,956	(1,996,657)					
6	Total				$ 47,824	$ (1,781,448)	(37.25)	(61.18)	23.93	$ 1,144,240	$ 3,135
7	**STATE INCOME TAX**				$ 15,523						
8	First Payment	12/15/22	04/01/23	107.00	$ 3,881	415,253					
9	Second Payment	03/15/23	04/01/23	17.00	3,881	65,975					
10	Third Payment	06/15/23	04/01/23	(75.00)	3,881	(291,065)					
11	Fourth Payment	09/15/23	04/01/23	(167.00)	3,881	(648,106)					
12	Total				$ 15,523	(457,943)	(29.50)	(61.18)	31.68	$ 491,722	$ 1,347
13	**PA PROPERTY TAX**				$ 1,868						
14	First Payment	04/30/23	04/01/23	(29.00)	$ 934	(27,086)					
15	Second Payment	08/31/23	04/01/23	(152.00)	934	(141,968)					
16	Total				$ 1,868	(169,054)	(90.50)	(61.18)	(29.32)	$ (54,777)	$ (150)
17	**PURTA**				$ 822						
18	Payment	05/01/23	04/01/23	(30.00)	$ 822	(24,660)	(30.00)	(61.18)	31.18	$ 25,627	$ 70
19	Total Working Capital For Other Taxes										$ 4,402

Prepaid Expenses

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Line #	Description		TOTAL	Insurance	PUC Assessment	Miscellaneous	Subscriptions	Postage	Rent	Maintenance & Services
1	September, 2020		10,751	3,791	2,112	436	52	9	-	4,351
2	October		10,488	3,343	1,877	540	121	11	-	4,596
3	November		10,472	2,908	1,642	1,325	104	6	-	4,487
4	December, 2020		12,689	2,485	1,408	4,609	36	1	-	4,150
5	January, 2021		13,645	2,165	1,173	4,309	152	-	-	5,846
6	February		11,191	1,724	939	1,773	112	4	-	6,639
7	March		8,617	1,308	704	541	174	5	-	5,885
8	April		7,566	1,253	469	455	215	2	-	5,172
9	May		6,575	935	235	405	187	1	-	4,812
10	June		5,399	496	-	329	129	2	-	4,443
11	July		10,518	5,218	-	275	192	2	-	4,831
12	August		10,558	4,880	-	285	65	2	-	5,326
13	September, 2021		12,147	4,370	2,636	296	51	-	-	4,794
14	TOTAL		$ 130,616	$ 34,876	$ 13,195	$ 15,578	$ 1,590	$ 45	$ -	$ 65,332
15	Percent to Gas			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Gas			$ 34,876	$ 13,195	$ 15,578	$ 1,590	$ 45	$ -	$ 65,332
17	Monthly Average	13		$ 2,683	$ 1,015	$ 1,198	$ 122	$ 3	$ -	$ 5,026
18	Rate Case Amount		$ 10,047							

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Gas Inventory

Line No.	Description	[1] Stored Underground
1	September, 2020	$ 19,873
2	October	23,542
3	November	23,202
4	December, 2020	18,952
5	January, 2021	12,597
6	February	6,238
7	March	2,560
8	April	5,494
9	May	9,583
10	June	15,888
11	July	23,011
12	August	31,104
13	September, 2021	39,519
14	Total	$ 231,563
15	Number of Months	13
16	Average Monthly Balance	$ 17,813

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Accumulated Deferred Income Taxes

		[1]	[2]
Line #	Description	Amount	Total
	Accumulated Deferred Income Tax		
1	Gas Utility Plant - a/c # 282	$ (633,775)	
2	Sub-total		(633,775)
3	ADIT on CIAC	27,405	
4	Sub-total		27,405
5	Federal ADIT		(606,370)
6	State Repair Regulatory Liability	(34,960)	(34,960)
7	Pro-Rata Adjustment	12,820	12,820
8	Balance At September 30, 2023		$ (628,510)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Customer Deposits

Line #	Description	[1] Balance At End Of Month
1	September, 2020	$ 22,386
2	October	$ 22,373
3	November	$ 22,331
4	December, 2020	$ 22,118
5	January, 2021	$ 21,930
6	February	$ 21,816
7	March	$ 21,634
8	April	$ 21,386
9	May	$ 21,040
10	June	$ 20,863
11	July	$ 20,873
12	August	$ 20,930
13	September, 2021	$ 21,120
14	Total	$ 280,800
15	Number of Months	13
16	Average Monthly Balance	$ 21,600

($ in Thousands)

Materials & Supplies

Line #	Month	[1] Materials & Supplies
1	September, 2020	$ 16,650
2	October	15,001
3	November	15,305
4	December, 2020	16,991
5	January, 2021	14,991
6	February	15,280
7	March	16,617
8	April	15,546
9	May	15,493
10	June	16,341
11	July	15,493
12	August	15,376
13	September, 2021	15,108
14	Total	$ 204,192
15	Number of Months	13
16	Average Monthly Balance	$ 15,707

($ in Thousands)

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

			[1]	[2]	[3]
		Factor	Pro Forma Test Year		
Line #	Description	Or Reference	At Present Rates	Rate Increase	At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 625,083	$ -	$ 625,083
2	Gas Supply & Cost Adjustment Revenue		427,354	-	427,354
3	Other Revenues		10,287	-	10,287
4	Revenue Increase			82,742	82,742
5	Total operating revenues		1,062,724	82,742	1,145,466
	OPERATING EXPENSES				
6	Manufactured Gas		997	-	997
7	Gas Supply Production		397,163	-	397,163
8	Transmission		-		
9	Distribution		88,222	-	88,222
10	Customer Accounts		42,370	-	42,370
11	Uncollectible Expense	1.647%	16,595	1,363	17,958
12	Customer Information & Services		13,864	-	13,864
13	Sales		1,738	-	1,738
14	Administrative & General		128,357	-	128,357
15	Depreciation & Amortization		125,537	-	125,537
16	Taxes other than income taxes		13,658	-	13,658
17	Total operating expenses		828,501	1,363	829,864
18	Net operating income Before Income Tax		234,223	81,379	315,602
	Income Taxes				
19	Pro Forma Income Tax At Present Rates		39,836		39,836
20	Pro Forma Income Tax on Revenue Increase			23,512	23,512
21	Net Income (loss)		$ 194,387	$ 57,867	$ 252,255

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Summary of Pro Forma Revenue and Expense
Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates: Budget For Year End 09/30/23	[3] Test Year At Present Rates: Adjustments Sch D-3 Increase (Decrease)	[4] Test Year At Present Rates: Pro Forma Adjusted For Test Year 9/30/23	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential (R/RT)	480	$ 621,416	$ 40,759	$ 662,175		$ 662,175
2	Comm & Ind (N/NT)	481	230,372	20,541	250,913		250,913
3	Comm & Ind (DS)	489	32,197	1,581	33,778		33,778
4	Lg Transport/Other	489	79,760	1,799	81,559		81,559
5	Interruptible	489	23,002	1,010	24,012		24,012
6	Forfeited Discounts		5,603	-	5,603		5,603
7	Miscellaneous Service Revenues		1,998	-	1,998		1,998
8	Rent from Gas Properties		2,338	348	2,686		2,686
9	Rate Increase			-	-	82,742	82,742
10	Total operating revenues		996,686	66,038	1,062,724	82,742	1,145,466
	OPERATING EXPENSES						
11	Gas Production		14	983	997		997
12	Gas Supply Production		358,286	38,877	397,163		397,163
13	Transmission		-		-		
14	Distribution		84,369	3,853	88,222		88,222
15	Customer Accounts		40,541	1,829	42,370		42,370
16	Uncollectible Expense	1.647%	14,419	2,176	16,595	1,363	17,958
17	Customer Information & Services		10,368	3,496	13,864		13,864
18	Sales		1,725	13	1,738		1,738
19	Administrative & General		116,044	12,313	128,357		128,357
20	Depreciation & Amortization		128,358	(2,821)	125,537		125,537
21	Taxes other than income taxes		13,360	298	13,658		13,658
22	Total operating expenses		767,484	61,017	828,501	1,363	829,864
23	Net Operating Income - BIT		$ 229,202	$ 5,021	$ 234,223	$ 81,379	$ 315,602

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description		[1] As Budgeted And Allocated	[2]	[3] Revenues	[4] Gas Costs	[5] Salaries & Wages	[6] Environmental Expense	[7] Other S&W Costs	[8] Rate Case	[9] Uncollectibles Expense	[10] ERP	[11] OSHA/ ETS	[12] Sub-Total Adjustments	[13] Total Proforma
					Adjustments										
	OPERATING REVENUES			D-4	D-5	D-6	D-7	D-8	D-9	D-10	D-11	D-12	D-13		
	Customer & Distribution Revenue														
1	Residential (R/RT)	480	$ 337,008		$ 12,022									$ 12,022	$ 349,030
2	Comm & Ind (N/NT)	481	131,562		6,629									6,629	138,191
3	Comm & Ind (DS)	489	31,555		1,629									1,629	33,184
4	Lg Transport/Other	489	79,189		1,477									1,477	80,666
5	Interruptible	489	23,002		1,010									1,010	24,012
	Revenue for Cost of Gas													-	-
6	Residential (R/RT)	480	284,408		28,737									28,737	313,145
7	Comm & Ind (N/NT)	481	98,810		13,912									13,912	112,722
8	Comm & Ind (DS)	489	642		(48)									(48)	594
9	Lg Transport/Other	489	571		322									322	893
10	Interruptible Transport	489	-		-									-	-
11	Forfeited Discounts		5,603		-									-	5,603
12	Miscellaneous Service Revenues		1,998		-									-	1,998
13	Rent from Gas Properties		2,338		348									348	2,686
14			-											-	-
15	Total operating revenues		996,686		66,038	-	-	-	-	-	-	-	-	66,038	1,062,724
	OPERATING EXPENSES														-
16	Gas Production		14				-	983						983	997
17	Gas Supply Production		358,286			38,877								38,877	397,163
18	Transmission		-												-
19	Distribution		84,369	-			611		1,910					2,521	86,890
20	Customer Accounts		40,541				216					92		309	40,850
21	Uncollectible Expense		14,419								2,176			2,176	16,595
22	Customer Information & Services		10,368				16						-	16	10,384
23	Sales		1,725				13							13	1,738
24	Administrative & General		116,044	-			330	2,327		55		-	1,883	4,595	120,639
25	Depreciation & Amortization		128,358											-	128,358
26	Taxes other than income taxes		13,360											-	13,360
														-	-
27	Total operating expenses		$ 767,484	$ -	$ -	$ 38,877	$ 1,186	$ 3,310	$ 1,910	$ 55	$ 2,176	$ 92	$ 1,883	$ 49,490	$ 816,974
28	Net operating income Before Income Tax		$ 229,202	$ -	$ 66,038	$ (38,877)	$ (1,186)	$ (3,310)	$ (1,910)	$ (55)	$ (2,176)	$ (92)	$ (1,883)	$ 16,548	$ 245,750

($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3] Benefits Adjustments D-14	[4] Other Adjustments D-15	[5] Universal Service D-16	[6] Adjustments Operations S & W D-17	[7] D-18	[8] EE&C Program D-19	[9]	[10] Depreciation D-21	[11] Taxes Other Than Income D-31	[12]	[13] TOTAL Adjusted
	OPERATING REVENUES													
29	**Customer & Distribution Revenue**													
30	Residential (R/RT)	$ 349,030												$ 349,030
31	Comm & Ind (N/NT)	138,191												138,191
32	Comm & Ind (DS)	33,184												33,184
33	Lg Transport/Other	80,666												80,666
34	Interruptible	24,012												24,012
	Revenue for Cost of Gas													-
35	Residential (R/RT)	313,145												313,145
36	Comm & Ind (N/NT)	112,722												112,722
37	Comm & Ind (DS)	594												594
38	Lg Transport/Other	893												893
39	Interruptible Transport	-												-
40	Forfeited Discounts	5,603												5,603
41	Miscellaneous Service Revenues	1,998												1,998
42	Rent from Gas Properties	2,686												2,686
43	-	-												-
44	Total operating revenues	1,062,724	-	-	-	-	-	-	-	-	-	-	-	1,062,724
	OPERATING EXPENSES													
45	Gas Production	997												997
46	Gas Supply Production	397,163												397,163
47	Transmission	-												-
48	Distribution	86,890			565		767							88,222
49	Customer Accounts	40,850			972	548								42,370
50	Uncollectible Expense	16,595												16,595
51	Customer Information & Services	10,384					-		3,480					13,864
52	Sales	1,738			-									1,738
53	Administrative & General	120,639		8,388	(670)		-							128,357
54	Depreciation & Amortization	128,358									(2,821)			125,537
55	Taxes other than income taxes	13,360										298		13,658
56	Total operating expenses	$ 816,974	$ -	$ 8,388	$ 867	$ 548	$ 767	$ -	$ 3,480	$ -	$ (2,821)	$ 298	$ -	$ 828,501
57	Net operating income Before Income Tax	$ 245,750	$ -	$ (8,388)	$ (867)	$ (548)	$ (767)	$ -	$ (3,480)	$ -	$ 2,821	$ (298)	$ -	$ 234,223

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Revenue Adjustments

		[1]	[2]	[3]	[4]	[5]	[6]
				PRO FORMA ADJUSTMENTS			
Line #	Description	Reference Or Account Number	2023 Budget	Other Adjustments	Rev/PGC Adj Annualization	Total Proforma Adjustments	Proforma Adjusted At Present Rates
						D-5A	
	Customer & Distribution Revenue						
1	Residential (R/RT)	480	$ 337,008	$ 12,022		$ 12,022	$ 349,030
2	Comm & Ind (N/NT)	481	131,562	6,629		6,629	138,191
3	Comm & Ind (DS)	489	31,555	1,629		1,629	33,184
4	Lg Transport/Other	489	79,189	1,477		1,477	80,666
5	Interruptible	489	23,002	1,010		1,010	24,012
6	Cust Chg & Distrib Revenue		602,316	22,767	-	22,767	625,083
	Revenue for Cost of Gas						
7	Residential (R/RT)	480	284,408	3,063	25,674	28,737	313,145
8	Comm & Ind (N/NT)	481	98,810	709	13,203	13,912	112,722
9	Comm & Ind (DS)	489	642	(48)		(48)	594
10	Lg Transport/Other	489	571	322		322	893
11	Interruptible Transport	489	-	-		-	-
12	Revenue for Cost of Gas		384,431	4,046	38,877	42,923	427,354
							-
13	Total Customer Revenue		986,747	26,813	38,877	65,690	1,052,437
14	Forfeited Discounts	487	5,603		-	-	5,603
15	Miscellaneous Service Revenues	488	923		-	-	923
							-
16	Rent from Gas Properties	493	2,338	348	-	348	2,686
17	Other Revenues	495	1,075			-	1,075
18	TOTAL REVENUES		$ 996,686	$ 27,161	$ 38,877	$ 66,038	$ 1,062,724

($ in Thousands)

Adjustment - Test Year Revenue Changes

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Factor Or Reference	Budgeted Jurisdictional	Revised Jurisdictional	Adjustment [3] - [2]	Total Adjustment
TOTAL REVENUE						
1	Residential (R/RT)		$ 621,416	$ 662,175	$ 40,759	
2	Comm & Ind (N/NT)		230,372	250,913	20,541	
3	Comm & Ind (DS)		32,197	33,778	1,581	
4	Lg Transport/Other		79,760	81,559	1,799	
5	Interruptible		23,002	24,012	1,010	
6	Total		$ 986,747	$ 1,052,437	$ 65,690	$ 65,690
COST OF COMMODITY						
7	Residential (R/RT)		$ 284,408	313,145	$ 28,737	
8	Comm & Ind (N/NT)		98,810	112,722	13,912	
9	Comm & Ind (DS)		642	594	(48)	
10	Lg Transport/Other		571	893	322	
11	Interruptible		0	0	0	
12	Total		$ 384,431	$ 427,354	$ 42,923	$ 42,923
NET CUSTOMER & DISTRIBUTION						
13	Residential (R/RT)		$ 337,008	$ 349,030	$ 12,022	
14	Comm & Ind (N/NT)		131,562	138,191	6,629	
15	Comm & Ind (DS)		31,555	33,184	1,629	
16	Lg Transport/Other		79,189	80,666	1,477	
17	Interruptible		23,002	24,012	1,010	
18	Total		$ 602,316	$ 625,083	$ 22,767	$ 22,767

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Operation and Maintenance Fee for Renewable Natural Gas (RNG) Interconnection

		[1]	[2]	[3]
Line #	Description	Factor Or Reference	Other Adjustments	Total
1	Annual Operation and Maintenance Fee for RNG Interconnection		$ 348	$ 348
2	Total ProForma Adjustment			$ 348

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Fully Projected Future Period - 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment - Gas Costs

		[1]	[2]	[3]	[4]	[5]
			PRO FORMA ADJUSTMENTS			
Line #	Description	Budgeted Gas Costs	D-5A Gas Costs		Gas Cost Pro Forma Adjustments	Pro Forma Gas Costs At Present Rates
1	Budgeted Gas Costs	$ 358,286			$ -	$ 358,286
2	Residential (R/RT)		25,674		25,674	25,674
3	Comm & Ind (N/NT)		13,203		13,203	13,203
4	Comm & Ind (DS)		-		-	-
5	Lg Transport/Other		-		-	-
6	Interruptible		-		-	-
7	**Total Gas Costs**	$ 358,286	$ 38,877	$ -	$ 38,877	$ 397,163

($ in Thousands)

Adjustment - Salaries & Wages

Line #	Description	[1] Budgeted Year 09/30/23	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Natural Gas Production Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Underground Storage Expenses	-	-	-	-	-
3	Total Transmission Operation Expenses	-	-	-	-	-
4	Total Distribution Operation Expenses	27,859	1,842	29,701	416	30,117
5	Customer Account Operations Expenses	14,479	-	14,479	216	14,695
6	Total Cust. Service & Inform. Operations Exp	1,042	-	1,042	16	1,058
7	Total Operation Sales Expenses	899	-	899	13	912
8	Total A & G Operation Expenses	20,661	543	21,204	309	21,513
9	Total Operations	64,940	2,385	67,325	970	68,295
	MAINTENANCE					
10	Total Underground Maintenance Expenses	-	-	-	-	-
11	Storage Maintenance Expenses	-	-	-	-	-
12	Total Transmission Maintenance Expenses	-	-	-	-	-
13	Total Distribution Maintenance Expenses	13,023	-	13,023	195	13,218
14	Total A&G Maintenance	1,395	-	1,395	21	1,416
15	Total Maintenance	14,418	-	14,418	216	14,634
16	Total Payroll to Expense	$ 79,358	$ 2,385	$ 81,743	$ 1,186	$ 82,929
17	Percent Increase					1.451%

($ in Thousands)

Adjustment - Salaries & Wages

Line #	Description	[1] Reference Or Function	[2] Union At 6-1	[3] Non-Exempt	[4] Exempt	[5] Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-23		$ 31,743	$ 30,950	$ 16,665	$ 79,358
	Annualize for Wage Increase to 9-30-23					
2	Percent Increase		3.00%	3.00%	3.00%	
3	Union Increase At 6/1 Annualization Factor	6/1/23	67%			
4	Non-Exempt Annualization Factor	4/1/23		50%		
5	Exempt Annualization Factor	12/1/22			17%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	638	464	83	$ 1,186
7	Annualized Salaries & Wages at 9-30-23 Rates	L 1 + L 6	$ 32,381	$ 31,414	$ 16,748	
8	Adjustments from Schedules D-9 & D-17				$ 2,385	
9	Pro Forma Salaries & Wages for TY		$ 32,381	$ 31,414	$ 19,133	
10	Pro Forma Adjustment to S&W					$ 1,186
11	Annualization Factor	L 11 / L 1				1.494%

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Adjustment - Environmental

Line #	Description	[1] Amount		[2] Total
	Environmental Adjustment - #1			
1	2019 Environmental expenditures	$ 4,811		
2	2020 Environmental expenditures	4,243		
3	2021 Environmental expenditures	6,460		
4	Three year average of Environmental expenditures	5,171		
5	Budgeted Environmental Expense	$ 4,188		
6	Pro Forma Adjustment			$ 983
	Environmental Adjustment - #2			
7	Environmental expenditures (through 9/30/19)	$ 7,701		
8	Less: Total recovery since last rate case	3,486	**(1)**	
9	Unrecovered expenditures	$ 4,215		
10	Amortization per year	1,865		
11	Recovery of current deferred Environmental expenditures included in the budget	1,865		
12	Pro Forma Adjustment			$ -

(1) Represents $3,242 recovery for costs prior to Fiscal 2018 and $244 recovery for Fiscal 2019 under recovered costs, per the 2020 Gas Rate Case at Docket No. R-2019-3015162.

Line #	Description	[1] Amount		[2] Total
	Environmental Adjustment - #3			
13	Environmental expenditures for Fiscal Years 2020 and 2021	$ 10,703		
14	Less: Total recovery through 9/30/21	8,376	**(2)**	
15	Unrecovered expenditures	$ 2,327		
16	Amortization Period - 1 year	1		
17	Pro Forma Adjustment			$ 2,327

(2) Represents $4,188 recovery for Fiscal Year 2020, per the 2019 Gas Rate Case at Docket No. R-2018-3006814 and $4,188 recovery for Fiscal Year 2021, per the 2020 Gas Rate Case at Docket No. R-2019-3015162.

($ in Thousands)

Adjustment - Salaries & Wages not included in Budget

Line #	Description	[1] Amount	[2] Total
	Adjustment 1 - Compensation Benchmarking Adjustment		
1	Compensation Benchmarking Adjustment	$ 1,148	
2	Incremental Incentive Bonus on Compensation Benchmarking Adjustment Above	51	
3	Compensation Benchmarking Adjustment Subtotal	1,199	
4	Employee Benefits on Benchmarking Adjustment (10% of Line 3)	120	
5	Compensation Benchmarking Adjustment Total		1,319
	Adjustment 2 - Cybersecurity		
6	Additional Positions to Implement Transportation Security Administration (TSA) Security Directives 2021#1 and 2021#2 Represents 5 additional position to implement above	505	
7	Employee Benefits on Additional Positions on Line 2 ($9,702 per employee)	49	
8	Incentive Bonus (7.5% of Line 6 Salary)	38	
9	Cybersecurity Adjustment Total		591
10	Pro Forma Adjustment		$ 1,910

Adjustment - Rate Case Expense

Line #	Description	[1] Reference	[2] Amount	[3] Total
	Rate Case Expenditures			
1	External Consultants		$ 364	
2	External Legal		650	
3	Miscellaneous Costs		41	
4	Sub-Total	L 1 to L 2		1,055
	Total Expenditures for Rate Case Filing			
5	TOTAL COSTS	L 3		$ 1,055
6	Normalized over 1 year (Line 4 / 3)		1	$ 1,055
7	Rate Case Expense included in Budget			1,000
8	Pro Forma Adjustment	L 5 - L 6		$ 55

($ in Thousands)

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2] / [3]	[5] Total [2] / [3]
Adjustment #1:						
1	2019		$ 14,400	$ 836,206	1.72%	
2	2020		$ 13,417	$ 837,568	1.60%	
3	2021		$ 13,706	$ 847,722	1.62%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 13,841	$ 840,499		1.647%
5	2023 Budget				$ 15,400	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.647%		$1,058,040		
7	Pro Forma at Present Rate Revenue	[1] * [3]			17,426	
8	Total for Test Year					$ 2,026
Adjustment #2:						
9	Regulatory Asset balance as of 9/30/21			$ 1,503 **(1)**		
10	Amortize over 10 years	**(2)**		10		
11	Pro Forma Adjustment (Line 9 / Line 10)					$ 150
12	Total Uncollectible Adjustment	L8 + L11				$ 2,176

(1) Includes $896 and $607 in 2021 and 2020, respectively, which was recorded as a regulatory asset associated with COVID-19 in accordance with the May 13, 2020 Secretarial Letter at Docket No. M-2020-3019775. These amounts are the uncollectible accounts reserve needed in excess of the $12,810 uncollectible expense built into rates (from the 2020 Gas Rate Case, Docket No. R-2019-3015162).
(2) Amortization period is in line with the settlement in the 2020 Gas Rate Case, Docket No. R-2019-3015162.

Adjustment - Emergency Relief Program

Line #	Description	[1] Amount	[2] Sub-total	[3] Pro Forma Adjustment
Emergency Relief Program (ERP) Adjustment				
1	Costs Incurred for Program (none recovered)		$ 922	
2	Amortization Period in Years	10		
3	Pro Forma Adjustment			$ 92

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Adjustment - OSHA/Emergency Temporary Standard (ETS) Compliance Costs

Line #	Description			[1] Amount	[2] Total
OSHA/ETS Adjustment #1					
1	Ongoing costs for tracking and testing			$ 1,692	
2	Pro Forma Adjustment				$ 1,692
OSHA/ETS Adjustment #2					
3	One-time costs for communication and legal advice			$ 191	
4	Amortization Period in Years		1		
5	Pro Forma Adjustment				$ 191
6	Total Pro Forma Adjustment				$ 1,883

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Adjustment - Benefits Adjustments

		[1]	[2]	[3]
Line #	Description	Amount	Subtotal	Pro Forma Adjustment
	Pension Expense Adjustment			
1	Total budgeted pension expense (income)		$ (2,887)	
2	Total cash contributions per estimate	11,364		
3	Estimated Cash Contributions attributable to UGI Gas	9,168		
4	Less: estimated capitalized portion (40%)	(3,667)		
5	Pension cash contributions per updated estimates		5,501	
6	Pro Forma Adjustment - Pension			$ 8,388

($ in Thousands)

Adjustment - Other Adjustments

Line #	Description	[1] Sub-Total	[2] Total
	Injuries & Damages Reserve Adjustment		
1	2019 Injuries & Damages Expense	$ 1,024	
2	2020 Injuries & Damages Expense	1,273	
3	2021 Injuries & Damages Expense	1,763	
4	Three Year Average of Injuries and Damages Expense	1,353	
5	Budgeted Injuries and Damanges Expense	$ 2,023	
6	Pro Forma Adjustment		$ (670)
	Customer Accounts Expense Adjustment		
7	Unrecovered Interest on Customer Deposits		$ 972
	Distribution Expense Adjustment		
8	Unbudgeted Annual Capacity Lease Charge		565

UGI Utilities, Inc. - Gas Division
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Adjustment - Universal Service

Line #	Description	[1] Amount
	Increase for Pro Forma TY Universal Service Expense	Pro Forma
	Budget	
1	Customer Assistance Plan Credit	$ 9,441
2	Administration Costs	1,570
3	LIURP	3,634
4	Hardship Program (Project Share)	22
5	Customer Assistance Plan Pre-program Arrearage	2,322
6	TOTAL	$ 16,989
7	Adjusted Budget	$ 17,537
8	Adjustment	$ 548

Succession Planning - Field Operations

Line #	Description	[1] Amount	[2] Total
1	Salary Adjustments for Succession Planning for Operations Represents 20 Unbudgeted Positions	20	$ 643
2	Employee Benefits on Positions Above	20	124
3	Total ProForma Adjustment		$ 767

Adjustment - Energy Efficiency and Conservation Programs

Line #	Description	[1] Amount	[2] Sub-Total
	Energy Efficiency and Conservation Programs		
1	2023 Original Program Costs	$ 9,239	
2	Adjusted Budget	$ 12,719	
3	Additional Expense Adjustment (Line 2 - Line 1)		3,480
4	Total Adjustment		$ 3,480

($ in Thousands)

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/23 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	-	-	-
7	Rights of Way	325.4	-	-	-
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-
10	Other Structures	329	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-
13	Field Lines	332	1	-	1
14	Field Measuring & Reg. Station Equipment	334	10	(9)	1
15	Drilling & Cleaning Equipment	335	-	-	-
16	Other Equipment	337	-	-	-
			-	-	-
17	TOTAL PRODUCTION & GATHERING		11	(9)	2
	NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
					-
29	TOTAL STORAGE & PROCESSING		-	-	-

($ in Thousands)

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/23 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-	-
31	Rights of Way	365.2	12	(1)	11
32	Structures & Improvements	366	6	(5)	1
33	Mains	367	460	(7)	453
34	Measuring & Regulating Station Equipment	369	96	(6)	90
35	Communication Equipment	370	118	(20)	98
36	Other Equipment	371	7	(1)	6
37	TOTAL TRANSMISSION		699	(40)	659
	DISTRIBUTION PLANT				
38	Land & Land Rights	374	46	-	46
39	Structures & Improvements	375	87	(2)	85
40	Mains	376	35,893	3,636	39,529
41	Measuring & Regulating Station Equipment	378	4,648	1,095	5,743
42	Measuring & Regulating Station Equipment	379	635	(31)	604
43	Services	380	35,147	981	36,128
44	Meters	381	5,791	(256)	5,535
45	Meter Installations	382	2,701	(123)	2,578
46	House Regulators	383	285	(138)	147
47	House Regulatory Installations	384	405	(30)	375
48	Industrial Measuring & Reg. Station Equipment	385	882	(65)	817
49	Other Property	386	23	1	24
50	Other Equipment	387	117	(13)	104
51	TOTAL DISTRIBUTION		86,660	5,055	91,715
	GENERAL PLANT				
52	Land & Land Rights	389	-	-	-
53	Structures & Improvements	390	6,059	(387)	5,672
54	Office Furniture & Equipment	391	23,929	(2,735)	21,194
55	Transportation Equipment	392	5,516	221	5,737
56	Stores Equipment	393	1	-	1
57	Tools & Garage Equipment	394	1,963	117	2,080
58	Laboratory Equipment	395	22	-	22
59	Power Operated Equipment	396	556	(109)	447
60	Communication Equipment	397	120	(13)	107
61	Miscellaneous Equipment	398	189	(1)	188
62	Other Tangible Property	399	-	-	-
63	TOTAL GENERAL		38,355	(2,907)	35,448
64	TOTAL DEPRECIATION		$ 125,725	$ 2,099	$ 127,824
65	CHARGED TO CLEARING ACCOUNTS		$ (8,155)	$ (216)	$ (8,371)
66	NET SALVAGE AMORTIZATION		$ 6,123	$ (39)	$ 6,084

UGI Utilities, Inc. - Gas Division
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Schedule D-31
Witness: T. A. Hazenstab

Adjustment - Taxes Other Than Income Taxes

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Account Number	Factor or Reference	Budget Amounts 9/30/23	Pro Forma Adjustments	Pro Forma Tax Expense 9/30/23
1	PURTA Taxes	408.1		$ 822	$ -	$ 822
2	Capital Stock	408.1		-		-
3	PA & Local Use taxes	408.1		1,868	-	1,868
4	Social Security	408.1	D-32	6,023	271	6,294
5	FUTA	408.1	D-32	113	5	118
6	SUTA	408.1	D-32	493	22	515
7	PUC Assessment	408.1		4,042	-	4,042
8	Total			$ 13,360	$ 298	$ 13,658

($ in Thousands)

Adjustment - Payroll Taxes

		[1]	[2]	[3]	[4]
Line #	Description	Account Number	Test Year 9/30/23 Present Rates	Pro Forma Adjustments	Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 79,358	$ 3,571	
2	FICA Expense		6,023		
3	FICA Expense - Percent	L 2 / L 1	7.59%	7.59%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 271
5	FUTA Expense		113		
6	FUTA Expense - Percent	L 5 / L 1	0.14%	0.14%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			5
8	SUTA Expense		493		
9	SUTA Expense - Percent	L 8 / L 1	0.62%	0.62%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			22
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 298

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($ in Thousands)

Schedule D-33
Witness: N. M. McKinney

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates [3] + [4]
1	Revenue			$ 1,062,724	$ 82,742	$ 1,145,466
2	Operating Expenses			(828,501)	(1,363)	(829,864)
3	OIBIT	L 1 + L 2		234,223	81,379	315,602
	Interest Expense					
4	Rate Base	Sch A-1	3,169,023			
5	Weighted Cost of Debt	Sch B-7	0.01790			
6	Synchronized Interest Expense	L 4 * L 5		(56,726)	-	(56,726)
7	Base Taxable Income	L 3 + L 6		177,497	81,379	258,876
8	Total Tax Depreciation	Sch D-34	$ 264,493			
9	Pro Forma Book Depreciation	Sch D-34	130,677			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(133,816)		(133,816)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ 43,681	$ 81,379	$ 125,060
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	9.99%	$ (4,364)	$ (8,130)	$ (12,493)
14	Total Tax Depreciation	Sch D-34	$ 232,078			
15	Pro Forma Book Depreciation	Sch D-34	130,677			
16	Federal Tax Deducts (Over) Under Book	L 14 - L 13		(101,401)	-	(101,401)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		71,732	73,249	144,981
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	(15,064)	(15,382)	(30,446)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		(19,428)	(23,512)	(42,940)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 127,824			
22	Total Tax Depreciation	Sch D-34	225,955			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		98,131	-	98,131
24	Deferred Federal Taxable Income	L 23		$ 98,131	$ -	$ 98,131
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(17,702)	-	(17,702)
	Deferred State Income Taxes					
26	Repairs			(3,110)		(3,110)
27	CIAC			80		80
28	State Deferred Income Tax (Expense)/Refund			(3,030)	-	(3,030)
29	Net Income Tax Expense	L20 + L 25 + L28		(40,160)	(23,512)	(63,672)
	Other Tax Adjustments					
30	ITC			324		324
31	Combined Income Tax Expense	L 29 + L 30		$ (39,836)	$ (23,512)	$ (63,348)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (32,442)	$ (15,382)	$ (47,824)
33	State Income Tax Expense	L 13 + L 28		(7,394)	(8,130)	(15,523)
34	Total Income Tax Expense	L 32 + L 33		$ (39,836)	$ (23,512)	$ (63,348)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

($ in Thousands)

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Gas Plant		$ 165,247	
2	Cost of Removal		6,123	
3	Repairs Tax Deduction		70,491	
4	Other Tax Basis Adjustments		(9,783)	
5	Total Federal Accelerated Tax Depreciation			$ 232,078
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		32,415	
7	Total State Accelerated Tax Depreciation			$264,493
	Straight Line Tax Depreciation			
8	Gas Plant		$ 127,824	
9	Total Tax Depreciation			$ 127,824
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 127,824	
11	Net Salvage Amortization		6,084	
12	Depreciation Charged to Clearing Accounts	(8,371)		
13	Estimated Percent of Clearing Charged to CWIP	39%		
14	Depreciation Charged to CWIP		(3,231)	
15	Book Depreciation for Tax Calculation			$ 130,677

($ in Thousands)

Gross Revenue Conversion Factor

		[1]	[2]	[3]
Line #	Description	Reference Or Factor	Tax Rate	Factor
	GROSS REVENUE CONVERSION FACTOR			
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.016470)
3	NET REVENUES	Sum L 1 to L 2		0.983530
4	STATE INCOME TAXES	[3] L 3 * Rate [2]	9.9900%	(0.098255)
5	FACTOR AFTER STATE TAXES	L 3 + L 4		0.885275
6	FEDERAL INCOME TAXES	[3] L 5 * Rate [2]	21.00%	(0.185908)
7	NET OPERATING INCOME FACTOR	L 5 + L 6		0.699367
8	GROSS REVENUE CONVERSION FACTOR	1 / L 7		1.429864
9	Combined Income Tax Factor On Gross Revenues	-L 4 - L 6		28.416%
	INCOME TAX FACTOR			
10	GROSS REVENUE FACTOR			1.000000
11	STATE INCOME TAXES	[3] L 10 * Rate [2]	9.9900%	(0.099900)
12	FACTOR AFTER STATE TAXES	L 10 + L 11		0.900100
13	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.189021)
14	NET OPERATING INCOME FACTOR	L 12 + L 13		0.711079
15	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.406314
16	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		28.892%

UGI GAS

EXHIBIT A – FUTURE

Future Period - 12 Months Ended September 30, 2022
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Summary of Measure of Value and Revenue Increase

Line #	Description	[1] Function	[2] Reference Section	[3] Pro Forma Test Year Ended September 30, 2022 At Present Rates	[4] Increase	[5] Proposed Rates
	RATE BASE					
1	Utility Plant		C-2	$ 4,597,404		$ 4,597,404
2	Accumulated Depreciation		C-3	(1,229,399)		(1,229,399)
3	Net Plant in service	L 1 + L 2		3,368,005	-	3,368,005
4	Working Capital		C-4	58,993		58,993
5	Gas Inventory		C-5	17,813		17,813
6	Accumulated Deferred Income Taxes		C-6	(620,597)		(620,597)
7	Customer Deposits		C-7	(21,600)		(21,600)
8	Materials & Supplies		C-8	15,707		15,707
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 2,818,321	$ -	$ 2,818,321
	OPERATING REVENUES AND EXPENSES					
	Operating Revenues					
10	Base Customer Charges		D-5	$ 642,925	$ 12,591	$ 655,516
11	Gas Cost Revenue		D-5	392,914		392,914
12	Other Operating Revenues		D-5	10,181		10,181
13	Total Revenues	Sum L 10 to L 12		1,046,020	12,591	1,058,611
14	Operating Expenses		D-1	(782,239)	(207)	(782,446)
15	OIBIT	L 13 + L 14		263,781	12,384	276,165
16	Pro Forma Income Tax at Present Rates		D-33	(51,067)		
17	Pro Forma Income Tax on Revenue Increase		D-33		(3,578)	(54,645)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 212,714	$ 8,806	$ 221,520
19	RATE OF RETURN	L 18 / L 9		7.5476%		7.8600%
	REVENUE INCREASE REQUIRED					
20	Rate of Return at Present Rates	L 19, Col 3		7.5476%		
21	Rate of Return Required		B-7	7.8600%		
22	Change in ROR	L 21 - L 20		0.3124%		
23	Change in Operating Income	L 22 * L 9		$ 8,806		
24	Gross Revenue Conversion Factor		D-35	1.429864		
25	Change in Revenues	L 23 * L 24		$ 12,591		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, C 4			1.96%	
27	Percent Increase -- Total Revenues	L 25 / L 13, C 4			1.20%	

($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-22
	UTILITY PLANT (101 - 106, 108)	
1	Gas Utility Plant	$ 4,597,404
2	Other Utility Plant	-
3	Total Plant In Service	4,597,404
4	Construction Work In Progress (107)	70,799
		-
5	Total Utility Plant	4,668,203
6	Accumulated Provision for Depreciation - Gas (108)	(1,229,399)
7	Utility Acquisition Adjustment (114)	182,145
8	Accumulated Provision for Depreciation - Other (119)	-
9	Net Utility Plant	3,620,949
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	239
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	1,078
13	Other Investments (124)	68
14	Total Other Property and Investments	1,385
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	5,416
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	85,442
18	Other Accounts Receivable (143)	83
19	Accum Provision for Uncollectible (144)	(10,788)
20	Receivables from Associated Companies (145)	101,297
21	Accounts Receivable Assoc. Comp. (146)	2,818
22	Plant Materials & Operating Supplies (154)	18,137
23	Stores Expense - Undistributed (163)	-
24	Gas Stored - Current (164.1)	41,462
25	Liquefied Natural Gas stored (164.2)	-
26	Prepayments (165)	14,940
27	Accrued Utility Revenues (173)	12,632
28	Miscellaneous Current & Accrued Assets (174)	-
29	Derivative Instrument Assets (175)	8,157
30	Total Current and Accrued Assets	279,596
	DEFERRED DEBITS	
31	Unamortized Debt Expense (181)	4,422
32	Other Regulatory Assets (182.3)	614,552
33	Other Preliminary Survey & Investigation Charges (183.2)	4,267
34	Clearing Accounts (184)	-
35	Miscellaneous Deferred Debits (186)	9,251
36	Unamortized Loss on Reacquired Debt (189)	-
37	Accumulated Deferred Income Taxes (190)	-
38	O/U Collected Gas (191.4, 191.41)	740
39	Total Deferred Debits	633,232
40	TOTAL ASSETS AND OTHER DEBITS	$ 4,535,162

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Budget TYE 9-30-22
	PROPRIETARY CAPITAL	
41	Common Stock Issued (201)	$ 55,318
42	Preferred Stock Issued (204)	-
43	Premium on Capital Stock (207)	559,879
44	Capital Stock Expense (214)	-
45	Retained Earnings (215, 215.2, 216)	997,145
46	Accum Other Comprehensive Income (219)	(23,424)
47	Total Proprietary Capital	1,588,918
	LONG TERM DEBT	
48	Bonds (221)	-
49	Advances from Associated Companies (223)	-
50	Other Long-Term Debt (224)	1,268,526
51	Unamortized Premium on LTD (225)	-
52	Unamortized Discount on LTD (226)	-
53	Total Long-term Debt	1,268,526
	OTHER NON-CURRENT LIABILITIES	
54	Obligations under Capital Leases (227)	-
55	Accum. Prov for Injuries & Damages (228.2)	1,870
56	Accum. Prov for Pensions & Benefits (228.3)	133,774
57	Accum. Miscellaneous Operating Prov (228.4)	42,703
58	Asset Retirement Obligation (230)	-
59	Total Non-Current Liabilities	178,347
	CURRENT & ACCRUED LIABILITIES	
60	Notes Payable (231)	150,345
61	Accounts Payable (232)	79,354
62	Notes Payable to Assoc. Companies (233)	111,794
63	Accounts Payable to Assoc. Cos (234)	15,381
64	Customer Deposits (235)	33,241
65	Taxes Accrued (236)	826
66	Interest Accrued (237)	11,581
67	Tax Collections Payable (241)	-
68	Accrued Interest on Other Liabilities (237)	51,417
69	Tax Collections Payable (241)	3,463
70	Misc Current & Accrued Liabilities (242)	-
71	Total Current & Accrued Liabilities	457,402
	OTHER DEFERRED CREDITS	
72	Customer Advances for Construction (252)	-
73	Other Deferred Credits (253)	12,316
74	Other Regulatory Liabilities (254)	293,112
75	Deferred ITC (255)	1,231
76	Accumulated Deferred Income Taxes (282)	695,103
77	Accumulated Deferred Income Taxes (283)	40,206
78	Total Other Deferred Credits	1,041,969
79	TOTAL LIABILITIES & OTHER CREDITS	$ 4,535,162

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Statement of Net Utility Operating Income

Line No	Description	[1] Budget TYE 9-30-22	[2] Reference
	Total Operating Revenues		
1	Total Sales Revenues	$ 991,527	B-3
2	Other Operating Revenues	9,891	B-3
3	Total Revenues	1,001,418	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	599,781	B-4 & D-2
5	Depreciation & Amortization Expense	117,074	D-2
6	Taxes Other Than Income Taxes	12,965	B-5
7	Total Operating Expenses	729,820	
8	Operating Income Before Income Taxes (OIBIT)	271,599	
	Income Taxes:		
9	State	12,474	B-5
10	Federal	38,593	B-5
11	Total Income Taxes	51,067	
12	**Net Utility Operating Income**	$ 220,531	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Statement of Operating Revenues

Line No	Description	[1] Budget TYE 9-30-22
	Gas Operating Revenues	
1	Residential (R/RT) (480)	$ 620,947
2	Comm & Ind (N/NT) (481)	231,544
3	Comm & Ind (DS) (489)	33,462
4	Lg Transport/Other (489)	81,752
5	Interruptible (489)	23,822
6	Sub-Total Gas Operating Revenues	991,527
	Other Operating Revenues	
7	Forfeited Discounts (487)	5,555
8	Miscellaneous Service Revenues (488)	923
9	Rent from Gas Properties (493)	2,338
10	Other Revenues (495)	1,075
11	Sub-Total Other Operating Revenues	9,891
12	**Total Operating Revenues**	$ 1,001,418

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-22
	Gas Raw Materials		
1	Liquefied Petroleum Gas Expenses	717	$ -
2	Miscellaneous Production Expenses	735	14
3	Total Gas Raw Materials Expenses		14
	Production and Gathering - Operations		
4	Operating Supervision and Engineering	750	-
5	Production Maps and Records	751	-
6	Gas Wells Expenses	752	-
7	Field Lines Expenses	753	-
8	Gas Well Royalties	758	-
9	Other Expenses	759	-
10	Total Production & Gathering Operation Expenses		-
	Production and Gathering - Maintenance		
11	Maintenance of Producing Gas Wells	763	-
12	Maintenance of Field Lines	764	-
13	Maintenance of Field Measuring and Reg. Station Equip.	766	-
14	Gas Supply Operation Expenses		-
	Other Gas Supply Expense - Operations		
15	Natural Gas City Gate Purchases	804.0	371,506
16	Other Gas Purchases	805.0	82
17	Purchases Gas Cost Adjustments	805.1	(29,104)
18	Gas Withdrawn from Storage-Debit	808.1	31,278
19	Purchased Gas Expenses	807.0	-
20	Gas Used for Other Utility Operations-Credit	812.0	-
21	Gas Delivered to Storage-Credit	808.2	(27,988)
22	Other Gas Supply Expenses	813.0	353
23	Gas Supply Operation Expenses		346,127
	Underground Storage Expense - Operation		
24	Operation Supervision and Engineering	814	-
25	Maps and Records	815	-
26	Wells Expenses	816	-
27	Lines Expenses	817	-
28	Measuring and Regulating Station Expenses	820	-
29	Purification Expenses	821	-
30	Gas Losses	823	-
31	Other Expenses	824	-
32	Total Underground Storage Expenses		-
	Underground Storage Expense - Maintenance		
33	Maintenance Supervision and Engineering	830	-
34	Maintenance of Structures and Improvements	831	-
35	Maintenance of Reservoirs and Wells	832	-
36	Maintenance of Lines	833	-
37	Maintenance of Measuring & Regulating Station Equip.	835	-
38	Total Underground Maintenance Expenses		-

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-22
	Transmission Expense - Operations		
39	Operating Supervision and Engineering	850	-
40	System Control and Load Dispatching	851	-
41	Communication System Expenses	852	-
42	Mains Expenses	856	-
43	Measuring and Regulating Station Expenses	857	-
44	Other Expenses	859	-
45	Total Transmission Operation Expenses		-
	Transmission Expense - Maintenance		
46	Maintenance Supervision and Engineering	861	-
47	Maintenance of Structures and Improvements	862	-
48	Maintenance of Mains	863	-
49	Maintenance of Measuring and Regulating Station Equip.	865	-
50	Maintenance of Communication Equipment	866	-
51	Total Transmission Maintenance Expenses		-
	Distribution Expense - Operations		
52	Operation Supervision and Engineering	870	3,317
53	Distribution Load Dispatching	871	2
54	Compressor Station Fuel and Power (Major Only)	873	-
55	Mains and Services Expenses	874	25,175
56	Measuring and Regulating Station Expenses-General	875	4,065
57	Measuring and Regulating Station Expenses-Industrial	876	13
58	Measuring and Regulating Station Expenses-City Gate	877	111
59	Meter and House Regulator Expenses	878	3,078
60	Customer Installations Expenses	879	2,663
61	Other Expenses	880	1,245
62	Rents	881	3,032
63	Total Distribution Operation Expenses		42,701
	Distribution Expense - Maintenance		
64	Maintenance Supervision and Engineering	885	495
65	Maintenance of Structures and Improvements	886	-
66	Maintenance of Mains	887	26,984
67	Maintenance of Compressor Station Equipment	888	-
68	Maintenance of Measuring & Reg. Station Equip.-Genl.	889	2,771
69	Maintenance of Measuring & Reg. Station Equip.-Indtrl.	890	4,556
70	Maintenance of Measuring & Reg. Station Equip.-City G	891	372
71	Maintenance of Services	892	1,499
72	Maintenance of Meters & House Regulators	893	-
73	Maintenance of Other Equipment	894	548
74	Construction & Maintenance	895	-
75	Total Distribution Maintenance Expenses		37,225
	Customer Accounts Expense - Operations		
76	Supervision	901	799
77	Meter Reading Expenses	902	2,112
78	Customer Records & Collection Expenses	903	34,943
79	Uncollectable Accounts	904	11,845
80	Miscellaneous Customer Accounts Expenses	905	2,143
81	Total Administrative & General		51,842

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Schedule B-4
Witness: T. A. Hazenstab

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Budget TYE 9-30-22
	Customer Service & Information Expense		
82	Supervision	907	167
83	Customer Assistance Expenses	908	870
84	Informational & Instructional Advertising Expenses	909	-
85	Miscellaneous Customer Service & Informational Exp.	910	9,183
86	Total Cust. Service & Inform. Operations Exp		10,220
87	Description		
	Sales Expense		
88	Supervision	911	414
89	Demonstrating and Selling Expenses	912	(612)
90	Advertising Expenses	913	1,587
91	Miscellaneous Sales Expenses	916	249
92	Total Operation Sales Expenses		1,638
	Administrative & General - Operations		
93	Administrative and General Salaries	920.0	33,895
94	Office Supplies and Expenses	921.0	20,600
95	Outside Service Employed	923.0	24,151
96	Property Insurance	924.0	-
97	Injuries and Damages	925.0	10,317
98	Employee Pensions and Benefits	926.0	13,188
99	Regulatory Commission Expenses	928.0	394
100	General Advertising Expenses	930.1	280
101	Miscellaneous General Expenses	930.2	2,642
102	Rents	931.0	37
103	Total A & G Operation Expenses		105,504
	Administrative & General - Maintenance		
104	A&G Maintenance of General Plant	932	4,255
105	A&G Maintenance of General Plant	935	255
106	Total A & G Maintenance Expenses		4,510
107	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 599,781
108	Total Gas Operation Expenses		558,046
109	Total Gas Maintenance Expense		41,735
110	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 599,781

($ in Thousands)

Detail of Taxes

Line No	Description	Reference	[1] Budget TYE 9-30-22
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 822
2	Capital Stock	D-31	-
3	PA and Local Use taxes	D-31	2,334
4	PUC Assessment	D-31	3,515
5	Subtotal		6,671
	Payroll Taxes		
6	FICA	D-31	5,694
7	SUTA	D-31	487
8	FUTA	D-31	113
9	Other		-
10	Subtotal		6,294
11	Total Taxes Other Than Income Taxes		$ 12,965
	Income Taxes		
12	State		$ 12,474
13	Federal		38,593
14	Total Income Taxes		$ 51,067

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Schedule B-6
Witness: P. R. Moul
Page 1 of 1

Composite Cost of Debt

Line No	Description	[1] Amount Outstanding	[2] Percent to Total	[3] Effective Interest Rate	[4] Average Weighted Cost Rate [2] * [3]
Medium Term Notes					
1	6.500% Due 8/15/2033	$ 20,000	1.42%	6.56%	0.09%
2	6.133% Due 10/15/2034	20,000	1.42%	6.19%	0.09%
Senior Unsecured Notes					
3	6.206% Due 9/30/2036	100,000	7.12%	6.32%	0.45%
4	4.980% Due 3/26/2044	175,000	12.46%	5.00%	0.62%
5	2.950% Due 6/30/2026	100,000	7.12%	3.92%	0.28%
6	4.120% Due 9/30/2046	200,000	14.23%	5.01%	0.71%
7	4.120% Due 10/31/2046	100,000	7.12%	4.28%	0.30%
8	3.120% Due 4/16/2050	150,000	10.68%	3.15%	0.34%
9	4.550% Due 02/01/2049	150,000	10.68%	4.58%	0.49%
10	1.590% Due 6/15/2026	100,000	7.12%	1.73%	0.12%
11	1.640% Due 9/15/2026	75,000	5.34%	1.75%	0.09%
12	3.687% Due 5/31/2052	90,000	6.41%	3.71%	0.24%
13	1.410% Due 7/31/2027	125,000	8.90%	1.53%	0.14%
14	Total Long-Term Debt	$ 1,405,000	100.00%		3.96%
15	Total Long-Term Debt	$ 1,405,000	100.00%	3.96%	3.96%
16	Total Short-Term Debt		0.00%		0.00%
17	TOTAL	$ 1,405,000	100.00%		
18	Weighted Cost of Debt				3.96%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Rate of Return

Line No	Description	[1] Capitalization Ratio	[2] Embedded Cost	[3] Statement Reference	[4] Return-%
1	Long-Term Debt	46.20%	3.96%	B-6	1.83%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	53.80%	11.20%		6.03%
4	Total	100.00%			7.86%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Measure of Value

		[1]	[2]	[3]	[4]	[5]
		Reference		Pro Forma Test Year Ended September 30, 2022 At		
Line #	Description	Schedule	# of Pages	Present Rates	Adjustments	Proposed Rates
	MEASURE OF VALUE					
1	Utility Plant	C-2	9	$ 4,597,404		$ 4,597,404
2	Accumulated Depreciation	C-3	11	(1,229,399)		(1,229,399)
3	Net Plant in service			3,368,005	-	3,368,005
4	Working Capital	C-4	9	58,993		58,993
5	Gas Inventory	C-5	1	17,813		17,813
6	Accumulated Deferred Income Taxes	C-6	1	(620,597)		(620,597)
7	Customer Deposits	C-7	1	(21,600)		(21,600)
8	Materials & Supplies	C-8	1	15,707		15,707
9	TOTAL MEASURE OF VALUE			$ 2,818,321	$ -	$ 2,818,321

($ in Thousands)

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma FTY 9-30-22
	INTANGIBLE PLANT		
1	Organization	301	$ 290
2	Franchise & Consent	302	194
3	Miscellaneous Intangible Plant	303	290
4	TOTAL INTANGIBLE		774
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	13
6	Producing Leaseholds	325	163
7	Rights of Way	325	30
8	Other Land Rights	326	1
9	Field Measuring & Regulating Station Structures	328	1
10	Other Structures	329	45
11	Producing Gas Wells-Well Construction	330	18
12	Producing Gas Wells-Well Equipment	331	24
13	Field Lines	332	751
14	Field Measuring & Reg. Station Equipment	334	90
15	Drilling & Cleaning Equipment	335	50
16	Other Equipment	337	11
17	TOTAL PRODUCTION & GATHERING		1,197
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	382
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		382

($ in Thousands)

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] Pro Forma FTY 9-30-22
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	$ 47
31	Rights of Way	365.2	868
32	Structures & Improvements	366	162
33	Mains	367	39,075
34	Measuring & Regulating Station Equipment	369	6,152
35	Communication Equipment	370	3,486
36	Other Equipment	371	351
37	TOTAL TRANSMISSION		50,141
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	11,700
39	Structures & Improvements	375	5,554
40	Mains	376	2,148,395
41	Measuring & Regulating Station Equipment	378	157,825
42	Measuring & Regulating Station Equipment	379	25,636
43	Services	380	1,386,389
44	Meters	381	175,939
45	Meter Installations	382	103,617
46	House Regulators	383	10,666
47	House Regulatory Installations	384	18,728
48	Industrial Measuring & Reg. Station Equipment	385	39,907
49	Other Property	386	1,046
50	Other Equipment	387	6,362
51	TOTAL DISTRIBUTION		4,091,764
	GENERAL PLANT		
52	Land & Land Rights	389	16,552
53	Structures & Improvements	390	141,083
54	Office Furniture & Equipment	391	205,177
55	Transportation Equipment	392	42,474
56	Stores Equipment	393	18
57	Tools & Garage Equipment	394	37,479
58	Laboratory Equipment	395	438
59	Power Operated Equipment	396	6,571
60	Communication Equipment	397	939
61	Miscellaneous Equipment	398	2,415
62	Other Tangible Property	399	-
63	TOTAL GENERAL		453,146
64	Total Plant		$ 4,597,404

($ in Thousands)

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Test Year 9/30/22 Budget	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Pg 4	$ 774	$ -	$ 774
2	Natural Gas Production & Gathering	Sch C-2, Pg 4	1,197	-	1,197
3	Natural Gas Storage & Processing Plant	Sch C-2, Pg 4	382	-	382
4	Transmission Plant	Sch C-2, Page 5	50,141	-	50,141
5	Distribution Plant	Sch C-2, Page 5	4,091,764	-	4,091,764
6	General Plant	Sch C-2, Page 5	453,146	-	453,146
7	Other Plant		-	-	-
8	Total Utility Plant		$ 4,597,404	$ -	$ 4,597,404

($ in Thousands)

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2021	[3] Year Ended September 30, 2022	[4] Pro Forma Adjustment	[5] Balance
	INTANGIBLE PLANT					
1	Organization	301	$ 290	$ 290	$ -	$ 290
2	Franchise & Consent	302	194	194	-	194
3	Miscellaneous Intangible Plant	303	290	290	-	290
4	TOTAL INTANGIBLE		774	774	-	774
	NATURAL GAS PRODUCTION & GATHERING					
5	Producing Lands	325.1	13	13	-	13
6	Producing Leaseholds	325.2	163	163	-	163
7	Rights of Way	325.4	30	30	-	30
8	Other Land Rights	325.5	1	1	-	1
9	Field Measuring & Regulating Station Structures	328	1	1	-	1
10	Other Structures	329	45	45	-	45
11	Producing Gas Wells-Well Construction	330	18	18	-	18
12	Producing Gas Wells-Well Equipment	331	24	24	-	24
13	Field Lines	332	751	751	-	751
14	Field Measuring & Reg. Station Equipment	334	90	90	-	90
15	Drilling & Cleaning Equipment	335	50	50	-	50
16	Other Equipment	337	11	11	-	11
17	TOTAL PRODUCTION & GATHERING		1,197	1,197	-	1,197
	NATURAL GAS STORAGE & PROCESSING PLANT					
18	Land & Land Rights	304	382	382	-	382
19	Production Plant-Manufactured Gas Plants	305	-	-	-	-
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	-	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	-	-	-	-
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		382	382	-	382

($ in Thousands)

Pro Forma Year End Plant Balances

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Account Number	Year Ended September 30, 2021	2022	Pro Forma Adjustment	Balance
	TRANSMISSION PLANT					
30	Land & Land Rights	365.1	47	47	-	47
31	Rights of Way	365.2	868	868	-	868
32	Structures & Improvements	366	162	162	-	162
33	Mains	367	39,075	39,075	-	39,075
34	Measuring & Regulating Station Equipment	369	6,152	6,152	-	6,152
35	Communication Equipment	370	3,486	3,486	-	3,486
36	Other Equipment	371	351	351	-	351
37	TOTAL TRANSMISSION		50,141	50,141	-	50,141
	DISTRIBUTION PLANT					
38	Land & Land Rights	374	11,700	11,700	-	11,700
39	Structures & Improvements	375	5,554	5,554	-	5,554
40	Mains	376	1,928,121	2,148,395	-	2,148,395
41	Measuring & Regulating Station Equipment	378	118,828	157,825	-	157,825
42	Measuring & Regulating Station Equipment	379	25,636	25,636	-	25,636
43	Services	380	1,321,301	1,386,389	-	1,386,389
44	Meters	381	166,600	175,939	-	175,939
45	Meter Installations	382	98,342	103,617	-	103,617
46	House Regulators	383	10,606	10,666	-	10,666
47	House Regulatory Installations	384	18,502	18,728	-	18,728
48	Industrial Measuring & Reg. Station Equipment	385	39,908	39,907	-	39,907
49	Other Property	386	1,047	1,046	-	1,046
50	Other Equipment	387	6,362	6,362	-	6,362
51	TOTAL DISTRIBUTION		3,752,507	4,091,764	-	4,091,764
	GENERAL PLANT					
52	Land & Land Rights	389	16,552	16,552	-	16,552
53	Structures & Improvements	390	132,257	141,083	-	141,083
54	Office Furniture & Equipment	391	216,400	205,177	-	205,177
55	Transportation Equipment	392	32,682	42,474	-	42,474
56	Stores Equipment	393	18	18	-	18
57	Tools & Garage Equipment	394	33,690	37,479	-	37,479
58	Laboratory Equipment	395	438	438	-	438
59	Power Operated Equipment	396	6,571	6,571	-	6,571
60	Communication Equipment	397	1,022	939	-	939
61	Miscellaneous Equipment	398	2,381	2,415	-	2,415
62	Other Tangible Property	399	16	-	-	-
63	TOTAL GENERAL		442,027	453,146	-	453,146
64	Total Plant		$ 4,247,028	$ 4,597,404	$ -	$ 4,597,404

($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Year ended September 30, 2021	[3] 2022
	Plant Additions			
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	(207)	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		(207)	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

($ in Thousands)

Additions to Plant

		[1]	[2]	[3]
Line #	Description	Account Number	Year ended September 30, 2021	2022
	TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	(10)	-
33	Mains	367	555	-
34	Measuring & Regulating Station Equipment	369	(12)	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		533	-
	DISTRIBUTION PLANT			
38	Land & Land Rights	374	368	-
39	Structures & Improvements	375	210	-
40	Mains	376	101,295	226,479
41	Measuring & Regulating Station Equipment	378	19,786	42,309
42	Measuring & Regulating Station Equipment	379	3,367	-
43	Services	380	174,938	72,015
44	Meters	381	10,483	11,057
45	Meter Installations	382	7,135	5,836
46	House Regulators	383	-	66
47	House Regulatory Installations	384	160	250
48	Industrial Measuring & Reg. Station Equipment	385	1,141	-
49	Other Property	386	-	-
50	Other Equipment	387	(214)	-
51	TOTAL DISTRIBUTION		318,669	358,012
	GENERAL PLANT			
52	Land & Land Rights	389	3,160	-
53	Structures & Improvements	390	32,154	9,480
54	Office Furniture & Equipment	391	17,019	14,239
55	Transportation Equipment	392	4,524	12,022
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	5,166	4,473
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	229	-
60	Communication Equipment	397	113	-
61	Miscellaneous Equipment	398	109	178
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		62,474	40,392
64	Total Plant		$ 381,469	$ 398,404

($ in Thousands)

Retirements

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2021	[3] Year Ended September 30, 2022
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

($ in Thousands)

Retirements

		[1]	[2]	[3]
Line		Account	Year Ended September 30,	
#	Description	Number	2021	2022
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	18	-
40	Mains	376	4,504	6,206
41	Measuring & Regulating Station Equipment	378	-	3,312
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	12,501	6,927
44	Meters	381	3,016	1,718
45	Meter Installations	382	-	561
46	House Regulators	383	-	6
47	House Regulatory Installations	384	-	24
48	Industrial Measuring & Reg. Station Equipment	385	-	-
49	Other Property	386	269	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		20,308	18,754
GENERAL PLANT				
52	Land & Land Rights	389	9	-
53	Structures & Improvements	390	643	654
54	Office Furniture & Equipment	391	6,362	25,464
55	Transportation Equipment	392	8,206	2,229
56	Stores Equipment	393	3	-
57	Tools & Garage Equipment	394	870	684
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	1,924	-
60	Communication Equipment	397	8	83
61	Miscellaneous Equipment	398	89	144
62	Other Tangible Property	399	-	16
63	TOTAL GENERAL		18,114	29,274
64	Total Plant		$ 38,422	$ 48,028

($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma FTY 9-30-22
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	162
7	Rights of Way	325	30
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	1
10	Other Structures	329	45
11	Producing Gas Wells-Well Construction	330	18
12	Producing Gas Wells-Well Equipment	331	24
13	Field Lines	332	726
14	Field Measuring & Reg. Station Equipment	334	85
15	Drilling & Cleaning Equipment	335	50
16	Other Equipment	337	11
17	TOTAL PRODUCTION & GATHERING		1,152
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	92
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	(36)
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		56

($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] Pro Forma FTY 9-30-22
	TRANSMISSION PLANT		
30	Land & Land Rights	365	-
31	Rights of Way	365	537
32	Structures & Improvements	366	146
33	Mains	367	21,888
34	Measuring & Regulating Station Equipment	369	3,966
35	Communication Equipment	370	2,141
36	Other Equipment	371	282
37	TOTAL TRANSMISSION		28,960
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	1,381
39	Structures & Improvements	375	3,256
40	Mains	376	477,478
41	Measuring & Regulating Station Equipment	378	26,619
42	Measuring & Regulating Station Equipment	379	8,409
43	Services	380	396,104
44	Meters	381	74,577
45	Meter Installations	382	36,059
46	House Regulators	383	6,699
47	House Regulatory Installations	384	8,897
48	Industrial Measuring & Reg. Station Equipment	385	17,515
49	Other Property	386	594
50	Other Equipment	387	4,401
51	TOTAL DISTRIBUTION		1,061,989
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	43,604
54	Office Furniture & Equipment	391	65,625
55	Transportation Equipment	392	11,359
56	Stores Equipment	393	6
57	Tools & Garage Equipment	394	12,824
58	Laboratory Equipment	395	112
59	Power Operated Equipment	396	2,417
60	Communication Equipment	397	402
61	Miscellaneous Equipment	398	893
62	Other Tangible Property	399	
63	TOTAL GENERAL		137,242
64	Total Plant		$ 1,229,399

($ in Thousands)

Summary of Accumulated Depreciation

Line #	Description	[1] Factor Or Reference	[2] Test Year Ended September 30, 2022 Amount	[3] Pro Forma Adjustment	[4] Balance
1	Intangible Plant	Sch C-3, Pg 4	$ -	$ -	$ -
2	Natural Gas Production & Gathering	Sch C-3, Pg 4	1,152	-	1,152
3	Natural Gas Storage & Processing Plant	Sch C-3, Pg 4	56	-	56
4	Transmission Plant	Sch C-3, Pg 5	28,960	-	28,960
5	Distribution Plant	Sch C-3, Pg 5	1,061,989	-	1,061,989
6	General Plant	Sch C-3, Pg 5	137,242	-	137,242
7	Other Plant		-	-	-
8	TOTAL ACC DEPR & AMORTIZATION		$ 1,229,399	$ -	$ 1,229,399

($ in Thousands)

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2021	[3] 2022	[4] Pro Forma Adjustment	[5] Balance
INTANGIBLE PLANT						
1	Organization	301	$ -	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-	-
4	TOTAL INTANGIBLE		-	-	-	-
NATURAL GAS PRODUCTION & GATHERING						
5	Producing Lands	325.1	-	-	-	-
6	Producing Leaseholds	325.2	162	162	-	162
7	Rights of Way	325.4	30	30	-	30
8	Other Land Rights	325.5	-	-	-	-
9	Field Measuring & Regulating Station Structures	328	1	1	-	1
10	Other Structures	329	45	45	-	45
11	Producing Gas Wells-Well Construction	330	18	18	-	18
12	Producing Gas Wells-Well Equipment	331	24	24	-	24
13	Field Lines	332	725	726	-	726
14	Field Measuring & Reg. Station Equipment	334	85	85	-	85
15	Drilling & Cleaning Equipment	335	49	50	-	50
16	Other Equipment	337	11	11	-	11
17	TOTAL PRODUCTION & GATHERING		1,150	1,152	-	1,152
NATURAL GAS STORAGE & PROCESSING PLANT						
18	Land & Land Rights	304	-	-	-	-
19	Production Plant-Manufactured Gas Plants	305	100	92	-	92
20	Land	350.1	-	-	-	-
21	Rights of Way	350.2	(52)	-	-	-
22	Structures & Improvements	351	-	-	-	-
23	Wells	352	-	(36)	-	(36)
24	Lines	353	-	-	-	-
25	Compressor Station Equipment	354	-	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-	-
27	Purification Equipment	356	-	-	-	-
28	Other Equipment	357	-	-	-	-
29	TOTAL STORAGE & PROCESSING		48	56	-	56

($ in Thousands)

Accumulated Depreciation by FERC Account

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Account Number	Year Ended September 30, 2021	2022	Pro Forma Adjustment	Balance
	TRANSMISSION PLANT					
30	Land & Land Rights	365.1	-	-	-	-
31	Rights of Way	365.2	525	537	-	537
32	Structures & Improvements	366	145	146	-	146
33	Mains	367	21,427	21,888	-	21,888
34	Measuring & Regulating Station Equipment	369	3,871	3,966	-	3,966
35	Communication Equipment	370	2,030	2,141	-	2,141
36	Other Equipment	371	276	282	-	282
37	TOTAL TRANSMISSION		28,274	28,960	-	28,960
	DISTRIBUTION PLANT					
38	Land & Land Rights	374	1,335	1,381	-	1,381
39	Structures & Improvements	375	3,159	3,256	-	3,256
40	Mains	376	450,869	477,478	-	477,478
41	Measuring & Regulating Station Equipment	378	26,331	26,619	-	26,619
42	Measuring & Regulating Station Equipment	379	7,763	8,409	-	8,409
43	Services	380	367,843	396,104	-	396,104
44	Meters	381	70,891	74,577	-	74,577
45	Meter Installations	382	33,971	36,059	-	36,059
46	House Regulators	383	5,525	6,699	-	6,699
47	House Regulatory Installations	384	8,438	8,897	-	8,897
48	Industrial Measuring & Reg. Station Equipment	385	16,637	17,515	-	17,515
49	Other Property	386	569	594	-	594
50	Other Equipment	387	4,290	4,401	-	4,401
51	TOTAL DISTRIBUTION		997,621	1,061,989	-	1,061,989
	GENERAL PLANT					
52	Land & Land Rights	389	-	-	-	-
53	Structures & Improvements	390	40,400	43,604	-	43,604
54	Office Furniture & Equipment	391	72,877	65,625	-	65,625
55	Transportation Equipment	392	9,545	11,359	-	11,359
56	Stores Equipment	393	5	6	-	6
57	Tools & Garage Equipment	394	11,577	12,824	-	12,824
58	Laboratory Equipment	395	90	112	-	112
59	Power Operated Equipment	396	1,925	2,417	-	2,417
60	Communication Equipment	397	373	402	-	402
61	Miscellaneous Equipment	398	650	893	-	893
62	Other Tangible Property	399	16	-	-	-
63	TOTAL GENERAL		137,458	137,242	-	137,242
64	Total Plant		$ 1,164,551	$ 1,229,399	$ -	$ 1,229,399

($ in Thousands)

Cost of Removal

		[1]	[2]	[3]
Line #	Description	Account Number	Year Ended September 30, 2021	2022
INTANGIBLE PLANT				
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330		
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305		
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		-	-

($ in Thousands)

Cost of Removal

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2021	[3] 2022
	TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	2	-
34	Measuring & Regulating Station Equipment	369	3	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		5	-
	DISTRIBUTION PLANT			
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	2,535	2,022
41	Measuring & Regulating Station Equipment	378	169	657
42	Measuring & Regulating Station Equipment	379	15	-
43	Services	380	4,191	3,575
44	Meters	381	1	1
45	Meter Installations	382	225	290
46	House Regulators	383	-	3
47	House Regulatory Installations	384	14	12
48	Industrial Measuring & Reg. Station Equipment	385	35	-
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		7,185	6,560
	GENERAL PLANT			
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	-	66
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	-	-
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	392	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		392	66
64	Total Plant		$ 7,582	$ 6,626

($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2021	[3] 2022
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	(8)	(23)
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	16	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		8	(23)

($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2021	[3] 2022
TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	1	1
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		1	1
DISTRIBUTION PLANT				
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	7	-
40	Mains	376	1,559	1,606
41	Measuring & Regulating Station Equipment	378	130	172
42	Measuring & Regulating Station Equipment	379	3	3
43	Services	380	4,791	4,364
44	Meters	381	(2)	(3)
45	Meter Installations	382	508	450
46	House Regulators	383	967	262
47	House Regulatory Installations	384	106	108
48	Industrial Measuring & Reg. Station Equipment	385	15	13
49	Other Property	386	-	-
50	Other Equipment	387	2	-
51	TOTAL DISTRIBUTION		8,086	6,975
GENERAL PLANT				
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	35	32
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(259)	(340)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	136	131
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(88)	(177)
64	Total Plant		$ 8,007	$ 6,776

($ in Thousands)

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2021	[3] 2022
	INTANGIBLE PLANT			
1	Organization	301	$ -	$ -
2	Franchise & Consent	302	-	-
3	Miscellaneous Intangible Plant	303	-	-
4	TOTAL INTANGIBLE		-	-
	NATURAL GAS PRODUCTION & GATHERING			
5	Producing Lands	325.1	-	-
6	Producing Leaseholds	325.2	-	-
7	Rights of Way	325.4	-	-
8	Other Land Rights	325.5	-	-
9	Field Measuring & Regulating Station Structures	328	-	-
10	Other Structures	329	-	-
11	Producing Gas Wells-Well Construction	330	-	-
12	Producing Gas Wells-Well Equipment	331	-	-
13	Field Lines	332	-	-
14	Field Measuring & Reg. Station Equipment	334	-	-
15	Drilling & Cleaning Equipment	335	-	-
16	Other Equipment	337	-	-
17	TOTAL PRODUCTION & GATHERING		-	-
	NATURAL GAS STORAGE & PROCESSING PLANT			
18	Land & Land Rights	304	-	-
19	Production Plant-Manufactured Gas Plants	305	(115)	-
20	Land	350.1	-	-
21	Rights of Way	350.2	-	-
22	Structures & Improvements	351	-	-
23	Wells	352	-	-
24	Lines	353	-	-
25	Compressor Station Equipment	354	-	-
26	Measuring & Regulating Equipment	355	-	-
27	Purification Equipment	356	-	-
28	Other Equipment	357	-	-
29	TOTAL STORAGE & PROCESSING		(115)	-

($ in Thousands)

Salvage

Line #	Description	[1] Account Number	[2] Year Ended September 30, 2021	[3] 2022
	TRANSMISSION PLANT			
30	Land & Land Rights	365.1	-	-
31	Rights of Way	365.2	-	-
32	Structures & Improvements	366	-	-
33	Mains	367	-	-
34	Measuring & Regulating Station Equipment	369	-	-
35	Communication Equipment	370	-	-
36	Other Equipment	371	-	-
37	TOTAL TRANSMISSION		-	-
	DISTRIBUTION PLANT			
38	Land & Land Rights	374	-	-
39	Structures & Improvements	375	-	-
40	Mains	376	-	-
41	Measuring & Regulating Station Equipment	378	-	(219)
42	Measuring & Regulating Station Equipment	379	-	-
43	Services	380	-	-
44	Meters	381	(19)	(4)
45	Meter Installations	382	-	-
46	House Regulators	383	-	-
47	House Regulatory Installations	384	-	-
48	Industrial Measuring & Reg. Station Equipment	385	-	-
49	Other Property	386	-	-
50	Other Equipment	387	-	-
51	TOTAL DISTRIBUTION		(19)	(223)
	GENERAL PLANT			
52	Land & Land Rights	389	-	-
53	Structures & Improvements	390	-	-
54	Office Furniture & Equipment	391	-	-
55	Transportation Equipment	392	(527)	(478)
56	Stores Equipment	393	-	-
57	Tools & Garage Equipment	394	-	-
58	Laboratory Equipment	395	-	-
59	Power Operated Equipment	396	-	-
60	Communication Equipment	397	-	-
61	Miscellaneous Equipment	398	-	-
62	Other Tangible Property	399	-	-
63	TOTAL GENERAL		(527)	(478)
64	Total Plant		$ (661)	$ (701)

Working Capital

Line No	Description	[1] Future FTY 9-30-22	[2] Reference
1	Working Capital for O & M Expense	$ 49,438	C-4, Page 2
2	Interest Payments	(4,248)	C-4, Page 7
3	Tax Payment Lag Calculations	3,756	C-4, Page 8
4	Prepaid Expenses	10,047	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 58,993	

($ in Thousands)

Summary of Working Capital

Line #	Description	[1] Reference	[2] Test Year Expenses	[3] Factor	[4] Number of (Lead) / Lag Days [2] * [3]	[5] Totals
	WORKING CAPITAL REQUIREMENT					
1	REVENUE LAG DAYS	Page 3				61.18
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 77,006	12.00	$ 924,077	
4	Purchased Gas Costs	Sch D-6	392,914	39.85	15,659,391	
5	Other Expenses	L 19 - L 2 to L 4	172,431	27.08	4,669,419	
6	Total	Sum (L 3 to L 5)	$ 642,351		$ 21,252,888	
7	O & M Expense Lag Days	L6, C 4 / C 2				33.09
8	Net (Lead) Lag Days	L 1 - L 7				28.09
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 1,760
10	Working Capital for O & M Expense	L 8 * L 9				$ 49,438
11	Interest Payments	Page 7				(4,248)
12	Tax Payment Lag Calculations	Page 8				3,756
13	Prepaid Expenses	Page 9				10,047
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 58,993
15	Pro Forma O & M Expense		$ 654,196			
	Less:					
16	Uncollectible Expense		11,845			
17	Sub-Total		11,845			
18	Pro Forma Cash O&M Expense		$ 642,351			

($ in Thousands)

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month	[3] Total Monthly Sales Page 2	[4] A/R Turnover [3] / [2]	[5] Days Lag 365 / [4]
1	Annual Number of Days					365
2	September, 2020		$ 52,950			
3	October		$ 61,679	$ 41,665		
4	November		$ 72,123	$ 55,297		
5	December, 2020		$ 106,368	$ 100,676		
6	January, 2021		$ 140,439	$ 126,612		
7	February		$ 164,061	$ 130,900		
8	March		$ 153,427	$ 128,921		
9	April		$ 133,479	$ 74,513		
10	May		$ 116,982	$ 48,952		
11	June		$ 100,284	$ 39,572		
12	July		$ 87,161	$ 31,323		
13	August		$ 76,062	$ 33,489		
14	September, 2021		$ 62,224	$ 32,352		
15	Total	Sum L 2 to L 14	$1,327,239			
16	Number of Months	13				
17	Average Acct Rec Balance	L 15 / L 16	$102,095			
18	Total Sales for Year	Sum L 2 to L 14		$ 844,272		
19	Acct Rec Turnover Ratio	L 18 / L 17			8.27	
20	Collection Lag Day Factor	L 1 / L 19				44.14
21	Meter Read Lag Factor					1.83
22	Midpoint Lag Factor		365 /	12 /	2 =	15.21
23	Total Revenue Lag Days	Sum L 20 to L 22				**61.18**

($ in Thousands)

Summary of Expense Lag Calculations

Line No.	Description	[1] Reference Or Factor	[2] Amount	[3] (Lead) / Lag Days	[4] Weighted Dollar Value [2] * [3]	[5] (Lead) / Lag Days [4] / [2]
PAYROLL						
1	Union Payrolls	Bi-Weekly	$ 30,619	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	46,386	12.00		
3	Weighted for Union	L1, C2 * C3			$ 367,432	
4	Weighted for Other	L2, C2 * C3			556,637	
5	Payroll Lag	L 3 + L 4	$ 77,006		$ 924,068	
6	Payroll Lag Days	C 4 / C 2				12.00
PURCHASE GAS COSTS						
7	Payment Lag	Page 6	$ 374,258		$ 14,915,898	
8	Gas Cost Lag Days	C 4 / C 2				39.85
OTHER O & M EXPENSES						
9	OCTOBER 2020	Page 5	$ 13,011		$ 464,688	
10	NOVEMBER 2020	Page 5	12,267		354,754	
11	DECEMBER 2020	Page 5	10,704		296,691	
12	JANUARY 2021	Page 5	13,154		403,634	
13	FEBRUARY 2021	Page 5	9,535		296,050	
14	MARCH 2021	Page 5	15,795		392,990	
15	APRIL 2021	Page 5	8,487		212,723	
16	MAY 2021	Page 5	11,246		236,159	
17	JUNE 2021	Page 5	13,342		293,544	
18	JULY 2021	Page 5	10,212		305,230	
19	AUGUST 2021	Page 5	11,697		290,457	
20	SEPTEMBER 2021	Page 5	13,828		332,536	
21	TOTAL		$ 143,277		$ 3,879,457	
22	Other O&M Expense Lag Days	L21, C 4 / C 2				27.08

($ in Thousands)

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
OCTOBER 2020					
1	Total Disbursements for Month	32,992	$ 57,092		
2	Total Disbursements for Expenses	5,068	$ 13,011	$ 464,688	35.72
NOVEMBER 2020					
3	Total Disbursements for Month	21,713	$ 41,983		
4	Total Disbursements for Expenses	4,909	$ 12,267	$ 354,754	28.92
DECEMBER 2020					
5	Total Disbursements for Month	21,745	$ 31,881		
6	Total Disbursements for Expenses	4,741	$ 10,704	$ 296,691	27.72
JANUARY 2021					
7	Total Disbursements for Month	22,708	$ 37,776		
8	Total Disbursements for Expenses	4,488	$ 13,154	$ 403,634	30.68
FEBRUARY 2021					
9	Total Disbursements for Month	19,680	$ 29,480		
10	Total Disbursements for Expenses	4,120	$ 9,535	$ 296,050	31.05
MARCH 2021					
11	Total Disbursements for Month	16,472	$ 34,931		
12	Total Disbursements for Expenses	4,961	$ 15,795	$ 392,990	24.88
APRIL 2021					
13	Total Disbursements for Month	25,582	$ 30,669		
14	Total Disbursements for Expenses	4,614	$ 8,487	$ 212,723	25.06
MAY 2021					
15	Total Disbursements for Month	28,733	$ 34,180		
16	Total Disbursements for Expenses	4,800	$ 11,246	$ 236,159	21.00
JUNE 2021					
17	Total Disbursements for Month	33,951	$ 49,835		
18	Total Disbursements for Expenses	5,546	$ 13,342	$ 293,544	22.00
JULY 2021					
19	Total Disbursements for Month	31,356	$ 42,313		
20	Total Disbursements for Expenses	5,502	$ 10,212	$ 305,230	29.89
AUGUST 2021					
21	Total Disbursements for Month	30,804	$ 37,118		
22	Total Disbursements for Expenses	5,756	$ 11,697	$ 290,457	24.83
SEPTEMBER 2021					
23	Total Disbursements for Month	36,824	$ 55,311		
24	Total Disbursements for Expenses	5,645	$ 13,828	$ 332,536	24.05
25	Total Test Month Expense Disbursement	60,150	$ 143,277	$ 3,879,457	27.08

Purchase Gas Cost Payment Lag Summary

Line #	Description	[1] Number of Invoices	[2] Amount of Invoice	[3] Dollar Days	[4] Total Payment Lag-Days
1	October 2020	28	$ 11,709	$ 418,248	35.72
2	November	38	35,682	1,031,745	28.92
3	December	28	30,793	1,407,814	45.72
4	January 2021	38	54,079	2,588,442	47.86
5	February	34	53,409	2,165,844	40.55
6	March	28	52,465	2,037,549	38.84
7	April	27	24,904	1,006,441	40.41
8	May	37	23,869	887,286	37.17
9	June	28	19,244	729,594	37.91
10	July	27	19,573	757,275	38.69
11	August	27	23,147	911,332	39.37
12	Septermber 2021	28	25,384	974,330	38.38
13	Total		$ 374,258	$ 14,915,898	
14	Purchase Gas Lag Days				39.85

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2022	Sch C-1			$ 2,818,321
2	Long-term Debt Ratio	Sch B-6			46.20%
3	Embedded Cost of Long-term Debt	Sch B-6			3.96%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 51,562
5	Daily Amount	L 4 / L 5 [2]	365		$ 141
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		61.18	
8	Interest Payment lag days	L 7 - L 6			(30.1)
9	Total Interest for Working Capital	L 5 * L 8			$ (4,248)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days [1] - [2]	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars [3] * [4]	[6] Payment Lead (Lag) Days [5] / [4]	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days [6] - [7]	[9] Total Dollar Days	[10] Working Capital Amount
											365
1	**FEDERAL INCOME TAX**				$ 40,934						
2	First Payment	01/15/22	04/01/22	76.00	$ 10,233	777,738					
3	Second Payment	03/15/22	04/01/22	17.00	10,233	173,968					
4	Third Payment	06/15/22	04/01/22	(75.00)	10,233	(767,505)					
5	Fourth Payment	09/15/22	04/01/22	(167.00)	10,233	(1,708,977)					
6	Total				$ 40,934	$ (1,524,776)	(37.25)	(61.18)	23.93	$ 979,377	$ 2,683
7	**STATE INCOME TAX**				$ 13,711						
8	First Payment	12/15/21	04/01/22	107.00	$ 3,428	366,776					
9	Second Payment	03/15/22	04/01/22	17.00	3,428	58,273					
10	Third Payment	06/15/22	04/01/22	(75.00)	3,428	(257,086)					
11	Fourth Payment	09/15/22	04/01/22	(167.00)	3,428	(572,445)					
12	Total				$ 13,711	(404,482)	(29.50)	(61.18)	31.68	$ 434,318	$ 1,190
13	**PA PROPERTY TAX**				$ 2,334						
14	First Payment	04/30/22	04/01/22	(29.00)	$ 1,167	(33,843)					
15	Second Payment	08/31/22	04/01/22	(152.00)	1,167	(177,384)					
16	Total				$ 2,334	(211,227)	(90.50)	(61.18)	(29.32)	$ (68,442)	$ (188)
17	**PURTA**				$ 822						
18	Payment	05/01/22	04/01/22	(30.00)	$ 822	(24,660)	(30.00)	(61.18)	31.18	$ 25,627	$ 70
19	Total Working Capital For Other Taxes										$ 3,756

Prepaid Expenses

Line #	Description	[1]	[2] TOTAL	[3] Insurance	[4] PUC Assessment	[5] Miscellaneous	[6] Subscriptions	[7] Postage	[8] Rent	[9] Maintenance & Services
1	September, 2020		10,751	3,791	2,112	436	52	9	-	4,351
2	October		10,488	3,343	1,877	540	121	11	-	4,596
3	November		10,472	2,908	1,642	1,325	104	6	-	4,487
4	December, 2020		12,689	2,485	1,408	4,609	36	1	-	4,150
5	January, 2021		13,645	2,165	1,173	4,309	152	-	-	5,846
6	February		11,191	1,724	939	1,773	112	4	-	6,639
7	March		8,617	1,308	704	541	174	5	-	5,885
8	April		7,566	1,253	469	455	215	2	-	5,172
9	May		6,575	935	235	405	187	1	-	4,812
10	June		5,399	496	-	329	129	2	-	4,443
11	July		10,518	5,218	-	275	192	2	-	4,831
12	August		10,558	4,880	-	285	65	2	-	5,326
13	September, 2021		12,147	4,370	2,636	296	51	-	-	4,794
14	TOTAL		$ 130,616	$ 34,876	$ 13,195	$ 15,578	$ 1,590	$ 45	$ -	$ 65,332
15	Percent to Gas			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Gas			$ 34,876	$ 13,195	$ 15,578	$ 1,590	$ 45	$ -	$ 65,332
17	Monthly Average	13		$ 2,683	$ 1,015	$ 1,198	$ 122	$ 3	$ -	$ 5,026
18	Rate Case Amount		$ 10,047							

($ in Thousands)

Gas Inventory

Line No.	Description	[1] Stored Underground
1	September, 2020	$ 19,873
2	October	23,542
3	November	23,202
4	December, 2020	18,952
5	January, 2021	12,597
6	February	6,238
7	March	2,560
8	April	5,494
9	May	9,583
10	June	15,888
11	July	23,011
12	August	31,104
13	September, 2021	39,519
14	Total	$ 231,563
15	Number of Months	13
16	Average Monthly Balance	$ 17,813

($ in Thousands)

Accumulated Deferred Income Taxes

Line #	Description	[1] Amount	[2] Total
	Accumulated Deferred Income Tax		
1	Gas Utility Plant - a/c # 282	$ (615,866)	
2	Sub-total		(615,866)
3	ADIT on CIAC	27,540	
4	Sub-total		27,540
5	Federal ADIT		(588,326)
6	State Repair Regulatory Liability	(32,271)	(32,271)
7	Pro-Rata Adjustment	-	-
8	Balance At September 30, 2022		$ (620,597)

($ in Thousands)

Customer Deposits

Line #	Description	[1] Balance At End Of Month
1	September, 2020	$ 22,386
2	October	$ 22,373
3	November	$ 22,331
4	December, 2020	$ 22,118
5	January, 2021	$ 21,930
6	February	$ 21,816
7	March	$ 21,634
8	April	$ 21,386
9	May	$ 21,040
10	June	$ 20,863
11	July	$ 20,873
12	August	$ 20,930
13	September, 2021	$ 21,120
14	Total	$ 280,800
15	Number of Months	13
16	Average Monthly Balance	$ 21,600

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Materials & Supplies

Line #	Month	[1] Materials & Supplies
1	September, 2020	$ 16,650
2	October	15,001
3	November	15,305
4	December, 2020	16,991
5	January, 2021	14,991
6	February	15,280
7	March	16,617
8	April	15,546
9	May	15,493
10	June	16,341
11	July	15,493
12	August	15,376
13	September, 2021	15,108
14	Total	$ 204,192
15	Number of Months	13
16	Average Monthly Balance	$ 15,707

($ in Thousands)

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

Line #	Description	Factor Or Reference	[1] Pro Forma Test Year At Present Rates	[2] Rate Increase	[3] At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 612,942	$ -	$ 612,942
2	Gas Supply & Cost Adjustment Revenue		422,897	-	422,897
3	Other Revenues		10,181	-	10,181
4	Revenue Increase			12,591	12,591
5	Total operating revenues		1,046,020	12,591	1,058,611
	OPERATING EXPENSES				
6	Manufactured Gas		14	-	14
7	Gas Supply Production		392,914	-	392,914
8	Transmission		-		
9	Distribution		81,281	-	81,281
10	Customer Accounts		40,869	-	40,869
11	Uncollectible Expense	1.647%	11,845	207	12,052
12	Customer Information & Services		13,743	-	13,743
13	Sales		1,651	-	1,651
14	Administrative & General		111,878	-	111,878
15	Depreciation & Amortization		114,913	-	114,913
16	Taxes other than income taxes		13,130	-	13,130
17	Total operating expenses		782,239	207	782,446
18	Net operating income Before Income Tax		263,781	12,384	276,165
	Income Taxes				
19	Pro Forma Income Tax At Present Rates		51,067		51,067
20	Pro Forma Income Tax on Revenue Increase			3,578	3,578
21	Net Income (loss)		$ 212,714	$ 8,806	$ 221,520

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Summary of Pro Forma Revenue and Expense
Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates: Budget For Year End 09/30/22	[3] Test Year At Present Rates: Adjustments Sch D-3 Increase (Decrease)	[4] Test Year At Present Rates: Pro Forma Adjusted For Test Year 9/30/22	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential (R/RT)	480	$ 620,947	$ 30,933	$ 651,880		$ 651,880
2	Comm & Ind (N/NT)	481	231,544	15,009	246,553		246,553
3	Comm & Ind (DS)	489	33,462	(59)	33,403		33,403
4	Lg Transport/Other	489	81,752	(1,531)	80,221		80,221
5	Interruptible	489	23,822	(40)	23,782		23,782
6	Forfeited Discounts		5,555	-	5,555		5,555
7	Miscellaneous Service Revenues		1,998	-	1,998		1,998
8	Rent from Gas Properties		2,338	290	2,628		2,628
9	Rate Increase			-	-	12,591	12,591
10	Total operating revenues		1,001,418	44,602	1,046,020	12,591	1,058,611
	OPERATING EXPENSES						
11	Gas Production		14	-	14		14
12	Gas Supply Production		346,127	46,787	392,914		392,914
13	Transmission		-		-		
14	Distribution		79,926	1,355	81,281		81,281
15	Customer Accounts		39,997	872	40,869		40,869
16	Uncollectible Expense	1.647%	11,845	-	11,845	207	12,052
17	Customer Information & Services		10,220	3,523	13,743		13,743
18	Sales		1,638	13	1,651		1,651
19	Administrative & General		110,014	1,864	111,878		111,878
20	Depreciation & Amortization		117,074	(2,161)	114,913		114,913
21	Taxes other than income taxes		12,965	165	13,130		13,130
22	Total operating expenses		729,820	52,419	782,239	207	782,446
23	Net Operating Income - BIT		$ 271,599	$ (7,817)	$ 263,781	$ 12,384	$ 276,165

($ in Thousands)

Summary of Pro Forma Adjustments

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
					Adjustments										
Line #	Description		As Budgeted And Allocated		Revenues	Gas Costs	Salaries & Wages	Environmental Expense	Other S&W Costs	Rate Case	Uncollectibles Expense	ERP	OSHA/ ETS	Sub-Total Adjustments	Total Proforma
	OPERATING REVENUES			D-4	D-5	D-6	D-7	D-8	D-9	D-10	D-11	D-12	D-13		
	Customer & Distribution Revenue														
1	Residential (R/RT)	480	$ 346,062		$ (4,532)									$ (4,532)	$ 341,530
2	Comm & Ind (N/NT)	481	135,721		(221)									(221)	135,500
3	Comm & Ind (DS)	489	32,820		(11)									(11)	32,809
4	Lg Transport/Other	489	81,181		(1,860)									(1,860)	79,321
5	Interruptible	489	23,822		(40)									(40)	23,782
	Revenue for Cost of Gas													-	-
6	Residential (R/RT)	480	274,885		35,465									35,465	310,350
7	Comm & Ind (N/NT)	481	95,823		15,230									15,230	111,053
8	Comm & Ind (DS)	489	642		(48)									(48)	594
9	Lg Transport/Other	489	571		329									329	900
10	Interruptible Transport	489	-		-									-	-
11	Forfeited Discounts		5,555		-									-	5,555
12	Miscellaneous Service Revenues		1,998		-									-	1,998
13	Rent from Gas Properties		2,338		290									290	2,628
14			-											-	-
15	Total operating revenues		1,001,418		44,602	-	-	-	-	-	-	-	-	44,602	1,046,020
	OPERATING EXPENSES														-
16	Gas Production		14				-	-						-	14
17	Gas Supply Production		346,127			46,787								46,787	392,914
18	Transmission		-												-
19	Distribution		79,926	-			584		630					1,214	81,140
20	Customer Accounts		39,997				210					0		210	40,207
21	Uncollectible Expense		11,845								-			-	11,845
22	Customer Information & Services		10,220				15						-	15	10,235
23	Sales		1,638				13							13	1,651
24	Administrative & General		110,014	-			300	-	296	-		-	1,269	1,864	111,878
25	Depreciation & Amortization		117,074											-	117,074
26	Taxes other than income taxes		12,965											-	12,965
														-	-
27	Total operating expenses		$ 729,820	$ -	$ -	$ 46,787	$ 1,122	$ -	$ 926	$ -	$ -	$ -	$ 1,269	$ 50,104	$ 779,924
28	Net operating income Before Income Tax		$ 271,599	$ -	$ 44,602	$ (46,787)	$ (1,122)	$ -	$ (926)	$ -	$ -	$ -	$ (1,269)	$ (5,502)	$ 266,096

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Summary of Pro Forma Adjustments

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
							Adjustments							
Line #	Description	From Page 1 Sub-total		Benefits Adjustments	Other Adjustments	Universal Service	Operations S & W		EE&C Program		Depreciation	Taxes Other Than Income		TOTAL Adjusted
	OPERATING REVENUES			D-14	D-15	D-16	D-17	D-18	D-19		D-21	D-31		
29	**Customer & Distribution Revenue**													
30	Residential (R/RT)	$ 341,530												$ 341,530
31	Comm & Ind (N/NT)	135,500												135,500
32	Comm & Ind (DS)	32,809												32,809
33	Lg Transport/Other	79,321												79,321
34	Interruptible	23,782												23,782
	Revenue for Cost of Gas													-
35	Residential (R/RT)	310,350												310,350
36	Comm & Ind (N/NT)	111,053												111,053
37	Comm & Ind (DS)	594												594
38	Lg Transport/Other	900												900
39	Interruptible Transport	-												-
40	Forfeited Discounts	5,555												5,555
41	Miscellaneous Service Revenues	1,998												1,998
42	Rent from Gas Properties	2,628												2,628
43	-	-												-
44	Total operating revenues	1,046,020	-	-	-	-	-	-	-	-	-	-	-	1,046,020
	OPERATING EXPENSES													
45	Gas Production	14												14
46	Gas Supply Production	392,914												392,914
47	Transmission	-												-
48	Distribution	81,140			141		-							81,281
49	Customer Accounts	40,207			-	662								40,869
50	Uncollectible Expense	11,845												11,845
51	Customer Information & Services	10,235					-		3,508					13,743
52	Sales	1,651			-									1,651
53	Administrative & General	111,878		-	-		-							111,878
54	Depreciation & Amortization	117,074									(2,161)			114,913
55	Taxes other than income taxes	12,965										165		13,130
56	Total operating expenses	$ 779,924	$ -	$ -	$ 141	$ 662	$ -	$ -	$ 3,508	$ -	$ (2,161)	$ 165	$ -	$ 782,239
57	Net operating income Before Income Tax	$ 266,096	$ -	$ -	$ (141)	$ (662)	$ -	$ -	$ (3,508)	$ -	$ 2,161	$ (165)	$ -	$ 263,781

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment - Revenue Adjustments

		[1]	[2]	[3]	[4]	[5]	[6]
				PRO FORMA ADJUSTMENTS			
Line #	Description	Reference Or Account Number	2022 Budget	Other Adjustments	Rev/PGC Adj Annualization	Total Proforma Adjustments D-5A	Proforma Adjusted At Present Rates
	Customer & Distribution Revenue						
1	Residential (R/RT)	480	$ 346,062	$ (4,532)		$ (4,532)	$ 341,530
2	Comm & Ind (N/NT)	481	135,721	(221)		(221)	135,500
3	Comm & Ind (DS)	489	32,820	(11)		(11)	32,809
4	Lg Transport/Other	489	81,181	(1,860)		(1,860)	79,321
5	Interruptible	489	23,822	(40)		(40)	23,782
6	Cust Chg & Distrib Revenue		619,606	(6,664)	-	(6,664)	612,942
	Revenue for Cost of Gas						
7	Residential (R/RT)	480	274,885	3,204	32,261	35,465	310,350
8	Comm & Ind (N/NT)	481	95,823	704	14,526	15,230	111,053
9	Comm & Ind (DS)	489	642	(48)		(48)	594
10	Lg Transport/Other	489	571	329		329	900
11	Interruptible Transport	489	-	-		-	-
12	Revenue for Cost of Gas		371,921	4,189	46,787	50,976	422,897
							-
13	Total Customer Revenue		991,527	(2,475)	46,787	44,312	1,035,839
14	Forfeited Discounts	487	5,555		-	-	5,555
15	Miscellaneous Service Revenues	488	923		-	-	923
							-
16	Rent from Gas Properties	493	2,338	290	-	290	2,628
17	Other Revenues	495	1,075			-	1,075
18	TOTAL REVENUES		$ 1,001,418	$ (2,185)	$ 46,787	$ 44,602	$ 1,046,020

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment - Test Year Revenue Changes

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Factor Or Reference	Budgeted Jurisdictional	Revised Jurisdictional	Adjustment [3] - [2]	Total Adjustment
TOTAL REVENUE						
1	Residential (R/RT)		$ 620,946	$ 651,879	$ 30,933	
2	Comm & Ind (N/NT)		231,545	246,554	15,009	
3	Comm & Ind (DS)		33,462	33,403	(59)	
4	Lg Transport/Other		81,752	80,221	(1,531)	
5	Interruptible		23,822	23,782	(40)	
6	Total		$ 991,527	$ 1,035,839	$ 44,312	$ 44,312
COST OF COMMODITY						
7	Residential (R/RT)		$ 274,884	310,349	$ 35,465	
8	Comm & Ind (N/NT)		95,824	111,054	15,230	
9	Comm & Ind (DS)		642	594	(48)	
10	Lg Transport/Other		571	900	329	
11	Interruptible		0	0	0	
12	Total		$ 371,921	$ 422,897	$ 50,976	$ 50,976
NET CUSTOMER & DISTRIBUTION						
13	Residential (R/RT)		$ 346,062	$ 341,530	$ (4,532)	
14	Comm & Ind (N/NT)		135,721	135,500	(221)	
15	Comm & Ind (DS)		32,820	32,809	(11)	
16	Lg Transport/Other		81,181	79,321	(1,860)	
17	Interruptible		23,822	23,782	(40)	
18	Total		$ 619,606	$ 612,942	$ (6,664)	$ (6,664)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment - Annual Lease for Maintenance of Renewable Natural Gas (RNG) Connection

		[1]	[2]	[3]
Line #	Description	Factor Or Reference	Other Adjustments	Total
1	Annual Rental for Maintaining RNG Interconnection		$ 290	$ 290
2	Total ProForma Adjustment			$ 290

($ in Thousands)

Adjustment - Gas Costs

		[1]	[2]	[3]	[4]	[5]
			PRO FORMA ADJUSTMENTS			
Line #	Description	Budgeted Gas Costs	D-5A Gas Costs		Gas Cost Pro Forma Adjustments	Pro Forma Gas Costs At Present Rates
1	Budgeted Gas Costs	$ 346,127			$ -	$ 346,127
2	Residential (R/RT)		32,261		32,261	32,261
3	Comm & Ind (N/NT)		14,526		14,526	14,526
4	Comm & Ind (DS)		-		-	-
5	Lg Transport/Other		-		-	-
6	Interruptible		-		-	-
7	**Total Gas Costs**	$ 346,127	$ 46,787	$ -	$ 46,787	$ 392,914

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Future Period - 12 Months Ended September 30, 2022
($ in Thousands)

Schedule D-7
Witness: T. A. Hazenstab
Page 1 of 2

Adjustment - Salaries & Wages

Line #	Description	[1] Budgeted Year 09/30/22	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Natural Gas Production Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Underground Storage Expenses	-	-	-	-	-
3	Total Transmission Operation Expenses	-	-	-	-	-
4	Total Distribution Operation Expenses	26,361	573	26,934	394	27,328
5	Customer Account Operations Expenses	14,060	-	14,060	210	14,270
6	Total Cust. Service & Inform. Operations Exp	1,012	-	1,012	15	1,027
7	Total Operation Sales Expenses	874	-	874	13	887
8	Total A & G Operation Expenses	18,644	271	18,915	279	19,194
9	Total Operations	60,951	844	61,795	911	62,706
	MAINTENANCE					
10	Total Underground Maintenance Expenses	-	-	-	-	-
11	Storage Maintenance Expenses	-	-	-	-	-
12	Total Transmission Maintenance Expenses	-	-	-	-	-
13	Total Distribution Maintenance Expenses	12,734	-	12,734	190	12,924
14	Total A&G Maintenance	1,355	-	1,355	21	1,376
15	Total Maintenance	14,089	-	14,089	211	14,300
16	Total Payroll to Expense	$ 75,040	$ 844	$ 75,884	$ 1,122	$ 77,006
17	Percent Increase					1.479%

($ in Thousands)

Adjustment - Salaries & Wages

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Reference Or Function	Union At 6-1	Non-Exempt	Exempt	Pro Forma Total Payroll
1	Budgeted Payroll For TY 9-30-22		$ 30,016	$ 29,266	$ 15,758	$ 75,040
	Annualize for Wage Increase to 9-30-22					
2	Percent Increase		3.00%	3.00%	3.00%	
3	Union Increase At 6/1 Annualization Factor	6/1/22	67%			
4	Non-Exempt Annualization Factor	4/1/22		50%		
5	Exempt Annualization Factor	12/1/21			17%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	603	439	79	$ 1,121
7	Annualized Salaries & Wages at 9-30-22 Rates	L 1 + L 6	$ 30,619	$ 29,705	$ 15,837	
8	Adjustments from Schedules D-9 & D-17				$ 844	
9	Pro Forma Salaries & Wages for TY		$ 30,619	$ 29,705	$ 16,681	
10	Pro Forma Adjustment to S&W					$ 1,121
11	Annualization Factor	L 11 / L 1				1.494%

($ in Thousands)

Adjustment - Salaries & Wages not included in Budget

Line #	Description	[1] Amount	[2] Total
	Adjustment 1 - Compensation Benchmarking Adjustment		
1	Compensation Benchmarking Adjustment	$ 523	
2	Incremental Incentive Bonus on Compensation Benchmarking Adjustment Above	50	
3	Compensation Benchmarking Adjustment Subtotal	573	
4	Employee Benefits on Benchmarking Adjustment (10% of Line 3)	57	
5	Compensation Benchmarking Adjustment Total		630
	Adjustment 2 - Cybersecurity		
6	Additional Positions to Implement Transportation Security Administration (TSA) Security Directives 2021#1 and 2021#2 Represents 5 additional position to implement above	253	
7	Employee Benefits on Additional Positions on Line 2 (5 @ $9,702 per employee) Prorated for 6-months	24	
8	Incentive Bonus (7.5% of Line 6 Salary)	19	
9	Cybersecurity Adjustment Total		296
10	ProForma Adjustment		$ 926

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule D-11
Witness: V. K. Ressler

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2] / [3]	[5] Total [2] / [3]
Adjustment #1:						
1	2019		$ 14,400	$ 836,206	1.72%	
2	2020		$ 13,417	$ 837,568	1.60%	
3	2021		$ 13,706	$ 847,722	1.62%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 13,841	$ 840,499		1.647%
5	2022 Budget				$ 12,810	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.647%		$1,041,394		
7	Pro Forma at Present Rate Revenue	[1] * [3]			17,152	
8	Total for Test Year					$ 4,342

Adjustment - OSHA/Emergency Temporary Standard (ETS) Compliance Costs

Line #	Description			[1] Amount	[2] Total
OSHA/ETS Adjustment #1					
1	Ongoing costs for tracking and testing			$ 1,269	
2	Pro Forma Adjustment				$ 1,269

Adjustment - Other Adjustments

Line #	Description	[1] Sub-Total	[2] Total
	Distribution Expense Adjustment		
1	Unbudgeted Annual Capacity Lease Charge		141

Adjustment - Universal Service

Line #	Description	[1] Amount
	Increase for Pro Forma TY Universal Service Expense	Pro Forma
	Budget	
1	Customer Assistance Plan Credit	$ 9,324
2	Administration Costs	1,522
3	LIURP	3,635
4	Hardship Program (Project Share)	59
5	Customer Assistance Plan Pre-program Arrearage	2,211
6	TOTAL	$ 16,751
7	Adjusted Budget	$ 17,413
8	Adjustment	$ 662

Adjustment - Energy Efficiency and Conservation Programs

Line #	Description	[1] Amount	[2] Sub-Total
	Energy Efficiency and Conservation Programs		
1	2022 Original Program Costs	$ 9,124	
2	Adjusted Budget	$ 12,632	
3	Additional Expense Adjustment (Line 2 - Line 1)		3,508
4	Total Adjustment		$ 3,508

($ in Thousands)

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/22 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	-	-	-
7	Rights of Way	325.4	-	-	-
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-
10	Other Structures	329	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-
13	Field Lines	332	1	-	1
14	Field Measuring & Reg. Station Equipment	334	10	(9)	1
15	Drilling & Cleaning Equipment	335	-	-	-
16	Other Equipment	337	-	-	-
			-	-	-
17	TOTAL PRODUCTION & GATHERING		11	(9)	2
	NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
					-
29	TOTAL STORAGE & PROCESSING		-	-	-

($ in Thousands)

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Budgeted 9/30/22 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-	-
31	Rights of Way	365.2	12	-	12
32	Structures & Improvements	366	6	(5)	1
33	Mains	367	459	(4)	455
34	Measuring & Regulating Station Equipment	369	96	(4)	92
35	Communication Equipment	370	118	(14)	104
36	Other Equipment	371	7	-	7
37	TOTAL TRANSMISSION		698	(27)	671
	DISTRIBUTION PLANT				
38	Land & Land Rights	374	46	-	46
39	Structures & Improvements	375	87	-	87
40	Mains	376	32,251	3,027	35,278
41	Measuring & Regulating Station Equipment	378	3,619	1,099	4,718
42	Measuring & Regulating Station Equipment	379	635	(14)	621
43	Services	380	33,429	1,204	34,633
44	Meters	381	5,475	(64)	5,411
45	Meter Installations	382	2,570	(93)	2,477
46	House Regulators	383	283	(121)	162
47	House Regulatory Installations	384	400	(19)	381
48	Industrial Measuring & Reg. Station Equipment	385	882	(44)	838
49	Other Property	386	23	1	24
50	Other Equipment	387	117	(10)	107
51	TOTAL DISTRIBUTION		79,817	4,966	84,783
	GENERAL PLANT				
52	Land & Land Rights	389	-	-	-
53	Structures & Improvements	390	5,446	(1,020)	4,426
54	Office Furniture & Equipment	391	19,386	(1,374)	18,012
55	Transportation Equipment	392	4,107	520	4,627
56	Stores Equipment	393	1	-	1
57	Tools & Garage Equipment	394	1,787	175	1,962
58	Laboratory Equipment	395	22	-	22
59	Power Operated Equipment	396	556	(85)	471
60	Communication Equipment	397	130	(19)	111
61	Miscellaneous Equipment	398	203	17	220
62	Other Tangible Property	399	-	-	-
63	TOTAL GENERAL		31,638	(1,786)	29,852
64	TOTAL DEPRECIATION		$ 112,164	$ 3,144	$ 115,308
65	CHARGED TO CLEARING ACCOUNTS		$ (6,580)	$ (591)	$ (7,171)
66	NET SALVAGE AMORTIZATION		$ 5,926	$ 850	$ 6,776

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule D-31
Witness: T. A. Hazenstab

Adjustment - Taxes Other Than Income Taxes

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Account Number	Factor or Reference	Budget Amounts 9/30/22	Pro Forma Adjustments	Pro Forma Tax Expense 9/30/22
1	PURTA Taxes	408.1		$ 822	$ -	$ 822
2	Capital Stock	408.1		-		-
3	PA & Local Use taxes	408.1		2,334	-	2,334
4	Social Security	408.1	D-32	5,694	149	5,843
5	FUTA	408.1	D-32	113	3	116
6	SUTA	408.1	D-32	487	13	500
7	PUC Assessment	408.1		3,515	-	3,515
8	Total			$ 12,965	$ 165	$ 13,130

($ in Thousands)

Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Test Year 9/30/22 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 75,040	$ 1,966	
2	FICA Expense		5,694		
3	FICA Expense - Percent	L 2 / L 1	7.59%	7.59%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 149
5	FUTA Expense		113		
6	FUTA Expense - Percent	L 5 / L 1	0.15%	0.15%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			3
8	SUTA Expense		487		
9	SUTA Expense - Percent	L 8 / L 1	0.65%	0.65%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			13
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 165

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
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($ in Thousands)

Schedule D-33
Witness: N. M. McKinney
Page 1 of 1

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates [3] + [4]
1	Revenue			$ 1,046,020	$ 12,591	$ 1,058,611
2	Operating Expenses			(782,239)	(207)	(782,446)
3	OIBIT	L 1 + L 2		263,781	12,384	276,165
	Interest Expense					
4	Rate Base	Sch A-1	2,818,321			
5	Weighted Cost of Debt	Sch B-7	0.01830			
6	Synchronized Interest Expense	L 4 * L 5		(51,575)	-	(51,575)
7	Base Taxable Income	L 3 + L 6		212,206	12,384	224,590
8	Total Tax Depreciation	Sch D-34	$ 237,437			
9	Pro Forma Book Depreciation	Sch D-34	119,316			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(118,121)		(118,121)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ 94,085	$ 12,384	$ 106,469
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	9.99%	$ (9,399)	$ (1,237)	$ (10,636)
14	Total Tax Depreciation	Sch D-34	$ 212,429			
15	Pro Forma Book Depreciation	Sch D-34	119,316			
16	Federal Tax Deducts (Over) Under Book	L 14 - L 13		(93,113)	-	(93,113)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		109,694	11,147	120,841
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	(23,036)	(2,341)	(25,377)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		(32,435)	(3,578)	(36,013)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 115,308			
22	Total Tax Depreciation	Sch D-34	206,504			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		91,196	-	91,196
24	Deferred Federal Taxable Income	L 23		$ 91,196	$ -	$ 91,196
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(15,881)	-	(15,881)
	Deferred State Income Taxes					
26	Repairs			(3,199)		(3,199)
27	CIAC			124		124
28	State Deferred Income Tax (Expense)/Refund			(3,075)	-	(3,075)
29	Net Income Tax Expense	L20 + L 25 + L28		(51,391)	(3,578)	(54,969)
	Other Tax Adjustments					
30	ITC			324		324
31	Combined Income Tax Expense	L 29 + L 30		$ (51,067)	$ (3,578)	$ (54,645)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (38,593)	$ (2,341)	$ (40,934)
33	State Income Tax Expense	L 13 + L 28		(12,474)	(1,237)	(13,711)
34	Total Income Tax Expense	L 32 + L 33		$ (51,067)	$ (3,578)	$ (54,645)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Gas Plant		$ 147,111	
2	Cost of Removal		5,925	
3	Repairs Tax Deduction		69,176	
4	Other Tax Basis Adjustments		(9,783)	
5	Total Federal Accelerated Tax Depreciation			$ 212,429
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		25,008	
7	Total State Accelerated Tax Depreciation			$237,437
	Straight Line Tax Depreciation			
8	Gas Plant		$ 115,308	
9	Total Tax Depreciation			$ 115,308
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 115,308	
11	Net Salvage Amortization		6,776	
12	Depreciation Charged to Clearing Accounts	(7,171)		
13	Estimated Percent of Clearing Charged to CWIP	39%		
14	Depreciation Charged to CWIP		(2,768)	
15	Book Depreciation for Tax Calculation			$ 119,316

UGI Utilities, Inc. - Gas Division
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($ in Thousands)

Schedule D-35
Witness: T. A. Hazenstab

Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
	GROSS REVENUE CONVERSION FACTOR			
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.016470)
3	NET REVENUES	Sum L 1 to L 2		0.983530
4	STATE INCOME TAXES	[3] L 3 * Rate [2]	9.9900%	(0.098255)
5	FACTOR AFTER STATE TAXES	L 3 + L 4		0.885275
6	FEDERAL INCOME TAXES	[3] L 5 * Rate [2]	21.00%	(0.185908)
7	NET OPERATING INCOME FACTOR	L 5 + L 6		0.699367
8	GROSS REVENUE CONVERSION FACTOR	1 / L 7		1.429864
9	Combined Income Tax Factor On Gross Revenues	-L 4 - L 6		28.416%
	INCOME TAX FACTOR			
10	GROSS REVENUE FACTOR			1.000000
11	STATE INCOME TAXES	[3] L 10 * Rate [2]	9.9900%	(0.099900)
12	FACTOR AFTER STATE TAXES	L 10 + L 11		0.900100
13	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.189021)
14	NET OPERATING INCOME FACTOR	L 12 + L 13		0.711079
15	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.406314
16	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		28.892%

UGI GAS

EXHIBIT A – HISTORIC

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission

Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)
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Historic Period - 12 Months Ended September 30, 2021

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SECTION D

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Summary of Measure of Value and Revenue Increase

		[1]	[2]	[3]	[4]	[5]
				Pro Forma Test Year Ended September 30, 2021 At		
Line #	Description	Function	Reference Section	Present Rates	Increase	Proposed Rates
RATE BASE						
1	Utility Plant		C-2	$ 4,247,028		$ 4,247,028
2	Accumulated Depreciation		C-3	(1,164,551)		(1,164,551)
3	Net Plant in service	L 1 + L 2		3,082,477	-	3,082,477
4	Working Capital		C-4	52,911		52,911
5	Gas Inventory		C-5	17,813		17,813
6	Accumulated Deferred Income Taxes		C-6	(601,705)		(601,705)
7	Customer Deposits		C-7	(21,600)		(21,600)
8	Materials & Supplies		C-8	15,707		15,707
9	TOTAL RATE BASE	Sum L 3 to L 8		$ 2,545,603	$ -	$ 2,545,603
OPERATING REVENUES AND EXPENSES						
	Operating Revenues					
10	Base Customer Charges		D-5	$ 612,457	$ (20,397)	$ 592,060
11	Gas Cost Revenue		D-5	331,546		331,546
12	Other Operating Revenues		D-5	11,634		11,634
13	Total Revenues	Sum L 10 to L 12		955,637	(20,397)	935,240
14	Operating Expenses		D	(689,332)	336	(688,996)
15	OIBIT	L 13 + L 14		266,305	(20,061)	246,244
16	Pro Forma Income Tax at Present Rates		D-33	(51,956)		
17	Pro Forma Income Tax on Revenue Increase		D-33		5,796	(46,160)
18	NET OPERATING INCOME	Sum L 15 to L 17		$ 214,349	$ (14,265)	$ 200,084
19	RATE OF RETURN	L 18 / L 9		8.4204%		7.8600%
REVENUE INCREASE REQUIRED						
20	Rate of Return at Present Rates	L 19, Col 3		8.4204%		
21	Rate of Return Required		B-7	7.8600%		
22	Change in ROR	L 21 - L 20		-0.5604%		
23	Change in Operating Income	L 22 * L 9		$ (14,265)		
24	Gross Revenue Conversion Factor		D-35	1.429864		
25	Change in Revenues	L 23 * L 24		$ (20,397)		
26	Percent Increase -- Delivery Revenues	L 25 / L 10, C 4			-3.33%	
27	Percent Increase -- Total Revenues	L 25 / L 13, C 4			-2.13%	

($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Actual TYE 9-30-21
	UTILITY PLANT (101 - 106, 108)	
1	Gas Utility Plant	$ 4,262,493
2	Other Utility Plant	-
3	Total Plant In Service	4,262,493
4	Construction Work In Progress (107)	70,799
5	Total Utility Plant	4,333,292
6	Accumulated Provision for Depreciation - Gas (108)	(1,194,592)
7	Utility Acquisition Adjustment (114)	182,145
8	Accumulated Provision for Depreciation - Other (119)	-
9	Net Utility Plant	3,320,845
	OTHER PROPERTY INVESTMENTS	
10	Non-utility Property (121)	239
11	Accumulated Depreciation on NUP (122)	-
12	Investment in Associated & Subsidiary Companies (123.1)	1,078
13	Other Investments (124)	75
14	Total Other Property and Investments	1,392
	CURRENT AND ACCRUED ASSETS	
15	Cash & Other Temporary Investments(131-136)	1,033
16	Unbilled Revenues	-
17	Customer Accounts Receivable (142)	82,421
18	Other Accounts Receivable (143)	5,459
19	Accum Provision for Uncollectible (144)	(14,851)
20	Receivables from Associated Companies (145)	101,297
21	Accounts Receivable Assoc. Comp. (146)	2,643
22	Plant Materials & Operating Supplies (154)	14,045
23	Stores Expense - Undistributed (163)	-
24	Gas Stored - Current (164.1)	39,519
25	Liquefied Natural Gas stored (164.2)	-
26	Prepayments (165)	12,343
27	Accrued Utility Revenues (173)	4,555
28	Miscellaneous Current & Accrued Assets (174)	946
29	Derivative Instrument Assets (175)	-
30	Total Current and Accrued Assets	249,410
	DEFERRED DEBITS	
31	Unamortized Debt Expense (181)	5,477
32	Other Regulatory Assets (182.3)	312,587
33	Other Preliminary Survey & Investigation Charges (183.2)	1,348
34	Clearing Accounts (184)	-
35	Miscellaneous Deferred Debits (186)	7,060
36	Deferred Losses from Disposition of Utility Plant (187)	-
37	Unamortized Loss on Reacquired Debt (189)	281,215
38	Accumulated Deferred Income Taxes (190)	-
39	Unrecovered Purchase Gas Costs (191)	-
40	Total Deferred Debits	607,687
41	TOTAL ASSETS AND OTHER DEBITS	$ 4,179,334

($ in Thousands)

Balance Sheet

Line No	Description/(Account No)	[1] Actual TYE 9-30-21
	PROPRIETARY CAPITAL	
42	Common Stock Issued (201)	$ 55,318
43	Preferred Stock Issued (204)	-
44	Premium on Capital Stock (207)	452,507
45	Capital Stock Expense (214)	-
46	Retained Earnings (215, 215.2, 216)	790,861
47	Accum Other Comprehensive Income (219)	(19,603)
48	Total Proprietary Capital	1,279,083
	LONG TERM DEBT	
49	Bonds (221)	-
50	Advances from Associated Companies (223)	-
51	Other Long-Term Debt (224)	1,215,263
52	Unamortized Premium on LTD (225)	-
53	Unamortized Discount on LTD (226)	-
54	Total Long-term Debt	1,215,263
	OTHER NON-CURRENT LIABILITIES	
55	Obligations under Capital Leases (227)	2,193
56	Accum. Prov for Injuries & Damages (228.2)	1,668
57	Accum. Prov for Pensions & Benefits (228.3)	78,790
58	Accum. Miscellaneous Operating Prov (228.4)	48,031
59	Asset Retirement Obligation (230)	111
60	Total Non-Current Liabilities	130,793
	CURRENT & ACCRUED LIABILITIES	
61	Notes Payable (231)	128,824
62	Accounts Payable (232)	53,413
63	Notes Payable to Assoc. Companies (233)	111,795
64	Accounts Payable to Assoc. Cos (234)	34,793
65	Customer Deposits (235)	21,120
66	Taxes Accrued (236)	93
67	Interest Accrued (237)	12,061
68	Tax Collections Payable (241)	1,971
69	Misc Current & Accrued Liabilities (242)	63,547
70	Obligations Under Capital Leases (243)	2,173
71	Derivative Instrument Liabilities (244)	-
72	Total Current & Accrued Liabilities	429,790
	OTHER DEFERRED CREDITS	
73	Customer Advances for Construction (252)	-
74	Other Deferred Credits (253)	30,975
75	Other Regulatory Liabilities (254)	326,173
76	Deferred ITC (255)	2,089
77	Accumulated Deferred Income Taxes (282)	724,962
78	Accumulated Deferred Income Taxes (283)	40,206
79	Total Other Deferred Credits	1,124,405
80	TOTAL LIABILITIES & OTHER CREDITS	$ 4,179,334

($ in Thousands)

Statement of Net Utility Operating Income

Line No	Description	[1] Actual TYE 9-30-21	[2] Reference
	Total Operating Revenues		
1	Total Sales Revenues	$ 844,210	B-3
2	Other Operating Revenues	11,634	B-3
3	Total Revenues	855,844	
	Total Operating Expenses		
4	Operation & Maintenance Expenses	499,599	B-4 & D-2
5	Depreciation & Amortization Expense	108,464	D-21
6	Taxes Other Than Income Taxes	8,707	B-5
7	Total Operating Expenses	616,770	
8	Operating Income Before Income Taxes (OIBIT)	239,074	
	Income Taxes:		
9	State	13,127	B-5
10	Federal	38,829	B-5
11	Total Income Taxes	51,956	
12	**Net Utility Operating Income**	$ 187,118	

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Schedule B-3
Witness: T. A. Hazenstab

Statement of Operating Revenues

Line No	Description	[1] Actual TYE 9-30-21
	Gas Operating Revenues	
1	Residential (R/RT) (480)	$ 506,222
2	Comm & Ind (N/NT) (481)	190,495
3	Comm & Ind (DS) (489)	46,750
4	Lg Transport/Other (489)	75,823
5	Interruptible (489)	24,920
6	Sub-Total Gas Operating Revenues	844,210
	Other Operating Revenues	
7	Forfeited Discounts (487)	4,882
8	Miscellaneous Service Revenues (488)	1,277
9	Rent from Gas Properties (493)	2,283
10	Other Revenues (495)	3,192
11	Sub-Total Other Operating Revenues	11,634
12	**Total Operating Revenues**	$ 855,844

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Schedule B-4
Witness: T. A. Hazenstab

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Actual TYE 9-30-21
	Gas Raw Materials		
1	Liquefied Petroleum Gas Expenses	717	$ -
2	Miscellaneous Production Expenses	735	29
3	Total Gas Raw Materials Expenses		29
	Production and Gathering - Operations		
4	Operating Supervision and Engineering	750	-
5	Production Maps and Records	751	-
6	Gas Wells Expenses	752	-
7	Field Lines Expenses	753	-
8	Gas Well Royalties	758	-
9	Other Expenses	759	-
10	Total Production & Gathering Operation Expenses		-
	Production and Gathering - Maintenance		
11	Maintenance of Producing Gas Wells	763	-
12	Maintenance of Field Lines	764	-
13	Maintenance of Field Measuring and Reg. Station Equip.	766	-
14	Gas Supply Operation Expenses		-
	Other Gas Supply Expense - Operations		
15	Natural Gas City Gate Purchases	804.0	357,994
16	Liquefied Natural Gas Purchases	804.1	163
17	Other Gas Purchases	805.0	542
18	Purchases Gas Cost Adjustments	805.1	(83,606)
19	Gas Withdrawn from Storage-Debit	808.1	26,406
20	Purchased Gas Expenses	807.0	-
21	Gas Used for Other Utility Operations-Credit	812.0	(928)
22	Gas Delivered to Storage-Credit	808.2	(44,991)
23	Other Gas Supply Expenses	813.0	6,895
24	Gas Supply Operation Expenses		262,475
	Underground Storage Expense - Operation		
25	Operation Supervision and Engineering	814	-
26	Maps and Records	815	-
27	Wells Expenses	816	-
28	Lines Expenses	817	-
29	Measuring and Regulating Station Expenses	820	-
30	Purification Expenses	821	-
31	Gas Losses	823	-
32	Other Expenses	824	-
33	Total Underground Storage Expenses		-
	Underground Storage Expense - Maintenance		
34	Maintenance Supervision and Engineering	830	-
35	Maintenance of Structures and Improvements	831	-
36	Maintenance of Reservoirs and Wells	832	-
37	Maintenance of Lines	833	-
38	Maintenance of Measuring & Regulating Station Equip.	835	-
39	Total Underground Maintenance Expenses		-

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Actual TYE 9-30-21
	Transmission Expense - Operations		
40	Operating Supervision and Engineering	850	-
41	System Control and Load Dispatching	851	-
42	Communication System Expenses	852	-
43	Mains Expenses	856	-
44	Measuring and Regulating Station Expenses	857	-
45	Other Expenses	859	-
46	Total Transmission Operation Expenses		-
	Transmission Expense - Maintenance		
47	Maintenance Supervision and Engineering	861	-
48	Maintenance of Structures and Improvements	862	-
49	Maintenance of Mains	863	-
50	Maintenance of Measuring and Regulating Station Equip.	865	-
51	Maintenance of Communication Equipment	866	-
52	Total Transmission Maintenance Expenses		-
	Distribution Expense - Operations		
53	Operation Supervision and Engineering	870	7,120
54	Distribution Load Dispatching	871	42
55	Compressor Station Fuel and Power (Major Only)	873	-
56	Mains and Services Expenses	874	21,479
57	Measuring and Regulating Station Expenses-General	875	1,384
58	Measuring and Regulating Station Expenses-Industrial	876	38
59	Measuring and Regulating Station Expenses-City Gate	877	275
60	Meter and House Regulator Expenses	878	3,331
61	Customer Installations Expenses	879	2,035
62	Other Expenses	880	1,482
63	Rents	881	4,074
64	Total Distribution Operation Expenses		41,260
	Distribution Expense - Maintenance		
65	Maintenance Supervision and Engineering	885	2,292
66	Maintenance of Structures and Improvements	886	-
67	Maintenance of Mains	887	13,726
68	Maintenance of Compressor Station Equipment	888	-
69	Maintenance of Measuring & Reg. Station Equip.-Genl.	889	1,789
70	Maintenance of Measuring & Reg. Station Equip.-Indtrl.	890	3,242
71	Maintenance of Measuring & Reg. Station Equip.-City G	891	113
72	Maintenance of Services	892	936
73	Maintenance of Meters & House Regulators	893	(2)
74	Maintenance of Other Equipment	894	340
75	Construction & Maintenance	895	-
76	Total Distribution Maintenance Expenses		22,436
	Customer Accounts Expense - Operations		
77	Supervision	901	477
78	Meter Reading Expenses	902	2,739
79	Customer Records & Collection Expenses	903	36,332
80	Uncollectable Accounts	904	11,927
81	Miscellaneous Customer Accounts Expenses	905	1,790
82	Total Administrative & General		53,265

($ in Thousands)

Operation and Maintenance Expenses

Line No	Description	Account No	[1] Actual TYE 9-30-21
	Customer Service & Information Expense		
83	Supervision	907	158
84	Customer Assistance Expenses	908	938
85	Informational & Instructional Advertising Expenses	909	-
86	Miscellaneous Customer Service & Informational Exp.	910	9,170
87	Total Cust. Service & Inform. Operations Exp		10,266
88	Description		
	Sales Expense		
89	Supervision	911	107
90	Demonstrating and Selling Expenses	912	617
91	Advertising Expenses	913	1,210
92	Miscellaneous Sales Expenses	916	127
93	Total Operation Sales Expenses		2,061
	Administrative & General - Operations		
94	Administrative and General Salaries	920.0	17,549
95	Office Supplies and Expenses	921.0	17,569
96	Outside Service Employed	923.0	36,517
97	Property Insurance	924.0	360
98	Injuries and Damages	925.0	7,126
99	Employee Pensions and Benefits	926.0	25,058
100	Regulatory Commission Expenses	928.0	772
101	General Advertising Expenses	930.1	-
102	Miscellaneous General Expenses	930.2	2,239
103	Rents	931.0	21
104	Total A & G Operation Expenses		107,211
	Administrative & General - Maintenance		
105	A&G Maintenance of General Plant	932	600
106	A&G Maintenance of General Plant	935	-
107	Total A & G Maintenance Expenses		600
108	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 499,603
109	Total Gas Operation Expenses		476,567
110	Total Gas Maintenance Expense		23,036
111	TOTAL OPERATION & MAINTENANCE EXPENSE		$ 499,603

($ in Thousands)

Detail of Taxes

Line No	Description	Reference	[1] Actual TYE 9-30-21
	Taxes Other Than Income Taxes		
	Non-revenue related:		
1	Pennsylvania - PURTA	D-31	$ 767
2	Capital Stock	D-31	-
3	PA and Local Use taxes	D-31	619
4	PUC Assessment	D-31	3,460
5	Subtotal		4,846
	Payroll Taxes		
6	FICA	D-31	3,614
7	SUTA	D-31	173
8	FUTA	D-31	74
9	Other		-
10	Subtotal		3,861
11	Total Taxes Other Than Income Taxes		$ 8,707
	Income Taxes		
12	State		$ 13,127
13	Federal		38,829
14	Total Income Taxes		$ 51,956

UGI Utilities, Inc. - Gas Division
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Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Schedule B-6
Witness: P. R. Moul
Page 1 of 1

Composite Cost of Debt

Line No	Description	[1] Amount Outstanding	[2] Percent to Total	[3] Effective Interest Rate	[4] Average Weighted Cost Rate [2] * [3]
Medium Term Notes					
1	6.500% Due 8/15/2033	$ 20,000	1.55%	6.56%	0.10%
2	6.133% Due 10/15/2034	20,000	1.55%	6.19%	0.10%
Senior Unsecured Notes					
3	6.206% Due 9/30/2036	100,000	7.74%	6.32%	0.49%
4	4.980% Due 3/26/2044	175,000	13.55%	5.00%	0.68%
5	2.950% Due 6/30/2026	100,000	7.74%	3.92%	0.30%
6	4.120% Due 9/30/2046	200,000	15.49%	5.01%	0.78%
7	4.120% Due 10/31/2046	100,000	7.74%	4.28%	0.33%
8	2.998% Due 10/31/2022	101,563	7.86%	3.11%	0.24%
9	4.550% Due 02/01/2049	150,000	11.61%	4.58%	0.53%
10	3.120% Due 04/16/2050	150,000	11.61%	3.15%	0.37%
11	1.590% Due 06/15/2026	100,000	7.74%	1.73%	0.13%
12	1.640% Due 09/15/2026	75,000	5.81%	1.75%	0.10%
13	Total Long-Term Debt	$ 1,291,563	100.00%		4.15%
14	Total Long-Term Debt	$ 1,291,563	100.00%	4.15%	4.15%
15	Total Short-Term Debt		0.00%		0.00%
16	TOTAL	$ 1,291,563	100.00%		
17	Weighted Cost of Debt				4.15%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Rate of Return

Line No	Description	[1] Capitalization Ratio	[2] Embedded Cost	[3] Statement Reference	[4] Return-%
1	Long-Term Debt	47.40%	4.15%	B-6	1.97%
2	Short-Term Debt	0.00%	0.00%	B-6	0.00%
3	Common Equity	52.60%	11.20%		5.89%
4	Total	100.00%			7.86%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Measure of Value

		[1]	[2]	[3]	[4]	[5]
		Reference		Pro Forma Test Year Ended September 30, 2021 At		
Line #	Description	Schedule	# of Pages	Present Rates	Adjustments	Proposed Rates
MEASURE OF VALUE						
1	Utility Plant	C-2	9	$ 4,247,028		$ 4,247,028
2	Accumulated Depreciation	C-3	11	(1,164,551)		(1,164,551)
3	Net Plant in service			3,082,477	-	3,082,477
4	Working Capital	C-4	9	52,911		52,911
5	Gas Inventory	C-5	1	17,813		17,813
6	Accumulated Deferred Income Taxes	C-6	1	(601,705)		(601,705)
7	Customer Deposits	C-7	1	(21,600)		(21,600)
8	Materials & Supplies	C-8	1	15,707		15,707
9	TOTAL MEASURE OF VALUE			$ 2,545,603	$ -	$ 2,545,603

($ in Thousands)

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] HTY 9-30-21
	INTANGIBLE PLANT		
1	Organization	301	$ 290
2	Franchise & Consent	302	194
3	Miscellaneous Intangible Plant	303	290
4	TOTAL INTANGIBLE		774
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	13
6	Producing Leaseholds	325	163
7	Rights of Way	325	30
8	Other Land Rights	326	1
9	Field Measuring & Regulating Station Structures	328	1
10	Other Structures	329	45
11	Producing Gas Wells-Well Construction	330	18
12	Producing Gas Wells-Well Equipment	331	24
13	Field Lines	332	751
14	Field Measuring & Reg. Station Equipment	334	90
15	Drilling & Cleaning Equipment	335	50
16	Other Equipment	337	11
17	TOTAL PRODUCTION & GATHERING		1,197
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	382
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350	-
21	Rights of Way	350	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		382

($ in Thousands)

Pro Forma Gas Plant in Service

Line No	Description	[1] Account No	[2] HTY 9-30-21
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	$ 47
31	Rights of Way	365.2	868
32	Structures & Improvements	366	162
33	Mains	367	39,075
34	Measuring & Regulating Station Equipment	369	6,152
35	Communication Equipment	370	3,486
36	Other Equipment	371	351
37	TOTAL TRANSMISSION		50,141
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	11,700
39	Structures & Improvements	375	5,554
40	Mains	376	1,928,121
41	Measuring & Regulating Station Equipment	378	118,828
42	Measuring & Regulating Station Equipment	379	25,636
43	Services	380	1,321,301
44	Meters	381	166,600
45	Meter Installations	382	98,342
46	House Regulators	383	10,606
47	House Regulatory Installations	384	18,502
48	Industrial Measuring & Reg. Station Equipment	385	39,908
49	Other Property	386	1,047
50	Other Equipment	387	6,362
51	TOTAL DISTRIBUTION		3,752,507
	GENERAL PLANT		
52	Land & Land Rights	389	16,552
53	Structures & Improvements	390	132,257
54	Office Furniture & Equipment	391	216,400
55	Transportation Equipment	392	32,682
56	Stores Equipment	393	18
57	Tools & Garage Equipment	394	33,690
58	Laboratory Equipment	395	438
59	Power Operated Equipment	396	6,571
60	Communication Equipment	397	1,022
61	Miscellaneous Equipment	398	2,381
62	Other Tangible Property	399	16
63	TOTAL GENERAL		442,027
64	Total Plant		$ 4,247,028

($ in Thousands)

Pro Forma Plant Adjustment Summary

Line #	Description	[1] Factor Or Reference	[2] Historic Test Year 09/30/21	[3] Adjustments	[4] Pro Forma Test Year [2] + [3]
1	Intangible Plant	Sch C-2, Pg 4	$ 774	$ -	$ 774
2	Natural Gas Production & Gathering	Sch C-2, Pg 4	1,197	-	1,197
3	Natural Gas Storage & Processing Plant	Sch C-2, Pg 4	382	-	382
4	Transmission Plant	Sch C-2, Page 5	50,141	-	50,141
5	Distribution Plant	Sch C-2, Page 5	3,752,507	-	3,752,507
6	General Plant	Sch C-2, Page 5	442,027	-	442,027
7	Other Plant		-	-	-
8	Total Utility Plant		$ 4,247,028	$ -	$ 4,247,028

($ in Thousands)

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Historic Test Year 2021	[3] Pro Forma Adjustment	[4] Balance
	INTANGIBLE PLANT				
1	Organization	301	$ 290	$ -	$ 290
2	Franchise & Consent	302	194	-	194
3	Miscellaneous Intangible Plant	303	290	-	290
4	TOTAL INTANGIBLE		774	-	774
	NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	13	-	13
6	Producing Leaseholds	325.2	163	-	163
7	Rights of Way	325.4	30	-	30
8	Other Land Rights	325.5	1	-	1
9	Field Measuring & Regulating Station Structures	328	1	-	1
10	Other Structures	329	45	-	45
11	Producing Gas Wells-Well Construction	330	18	-	18
12	Producing Gas Wells-Well Equipment	331	24	-	24
13	Field Lines	332	751	-	751
14	Field Measuring & Reg. Station Equipment	334	90	-	90
15	Drilling & Cleaning Equipment	335	50	-	50
16	Other Equipment	337	11	-	11
17	TOTAL PRODUCTION & GATHERING		1,197	-	1,197
	NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	382	-	382
19	Production Plant-Manufactured Gas Plants	305	-	-	-
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
29	TOTAL STORAGE & PROCESSING		382	-	382

($ in Thousands)

Pro Forma Year End Plant Balances

Line #	Description	[1] Account Number	[2] Historic Test Year 2021	[3] Pro Forma Adjustment	[4] Balance
	TRANSMISSION PLANT				
30	Land & Land Rights	365.1	47	-	47
31	Rights of Way	365.2	868	-	868
32	Structures & Improvements	366	162	-	162
33	Mains	367	39,075	-	39,075
34	Measuring & Regulating Station Equipment	369	6,152	-	6,152
35	Communication Equipment	370	3,486	-	3,486
36	Other Equipment	371	351	-	351
37	TOTAL TRANSMISSION		50,141	-	50,141
	DISTRIBUTION PLANT				
38	Land & Land Rights	374	11,700	-	11,700
39	Structures & Improvements	375	5,554	-	5,554
40	Mains	376	1,928,121	-	1,928,121
41	Measuring & Regulating Station Equipment	378	118,828	-	118,828
42	Measuring & Regulating Station Equipment	379	25,636	-	25,636
43	Services	380	1,321,301	-	1,321,301
44	Meters	381	166,600	-	166,600
45	Meter Installations	382	98,342	-	98,342
46	House Regulators	383	10,606	-	10,606
47	House Regulatory Installations	384	18,502	-	18,502
48	Industrial Measuring & Reg. Station Equipment	385	39,908	-	39,908
49	Other Property	386	1,047	-	1,047
50	Other Equipment	387	6,362	-	6,362
51	TOTAL DISTRIBUTION		3,752,507	-	3,752,507
	GENERAL PLANT				
52	Land & Land Rights	389	16,552	-	16,552
53	Structures & Improvements	390	132,257	-	132,257
54	Office Furniture & Equipment	391	216,400	-	216,400
55	Transportation Equipment	392	32,682	-	32,682
56	Stores Equipment	393	18	-	18
57	Tools & Garage Equipment	394	33,690	-	33,690
58	Laboratory Equipment	395	438	-	438
59	Power Operated Equipment	396	6,571	-	6,571
60	Communication Equipment	397	1,022	-	1,022
61	Miscellaneous Equipment	398	2,381	-	2,381
62	Other Tangible Property	399	16	-	16
63	TOTAL GENERAL		442,027	-	442,027
64	Total Plant		$ 4,247,028	$ -	$ 4,247,028

($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	Plant Additions		
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	(207)
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		(207)
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

($ in Thousands)

Additions to Plant

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	(10)
33	Mains	367	555
34	Measuring & Regulating Station Equipment	369	(12)
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		533
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	368
39	Structures & Improvements	375	210
40	Mains	376	101,295
41	Measuring & Regulating Station Equipment	378	19,786
42	Measuring & Regulating Station Equipment	379	3,367
43	Services	380	174,938
44	Meters	381	10,483
45	Meter Installations	382	7,135
46	House Regulators	383	-
47	House Regulatory Installations	384	160
48	Industrial Measuring & Reg. Station Equipment	385	1,141
49	Other Property	386	-
50	Other Equipment	387	(214)
51	TOTAL DISTRIBUTION		318,669
	GENERAL PLANT		
52	Land & Land Rights	389	3,160
53	Structures & Improvements	390	32,154
54	Office Furniture & Equipment	391	17,019
55	Transportation Equipment	392	4,524
56	Stores Equipment	393	-
57	Tools & Garage Equipment	394	5,166
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	229
60	Communication Equipment	397	113
61	Miscellaneous Equipment	398	109
62	Other Tangible Property	399	-
63	TOTAL GENERAL		62,474
64	Total Plant		$ 381,469

($ in Thousands)

Retirements

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	-
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

($ in Thousands)

Retirements

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	-
33	Mains	367	-
34	Measuring & Regulating Station Equipment	369	-
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	-
39	Structures & Improvements	375	18
40	Mains	376	4,504
41	Measuring & Regulating Station Equipment	378	-
42	Measuring & Regulating Station Equipment	379	-
43	Services	380	12,501
44	Meters	381	3,016
45	Meter Installations	382	-
46	House Regulators	383	-
47	House Regulatory Installations	384	-
48	Industrial Measuring & Reg. Station Equipment	385	-
49	Other Property	386	269
50	Other Equipment	387	-
51	TOTAL DISTRIBUTION		20,308
	GENERAL PLANT		
52	Land & Land Rights	389	9
53	Structures & Improvements	390	643
54	Office Furniture & Equipment	391	6,362
55	Transportation Equipment	392	8,206
56	Stores Equipment	393	3
57	Tools & Garage Equipment	394	870
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	1,924
60	Communication Equipment	397	8
61	Miscellaneous Equipment	398	89
62	Other Tangible Property	399	-
63	TOTAL GENERAL		18,114
64	Total Plant		$ 38,422

($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] HTY 9-30-21
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325	-
6	Producing Leaseholds	325	162
7	Rights of Way	325	30
8	Other Land Rights	326	-
9	Field Measuring & Regulating Station Structures	328	1
10	Other Structures	329	45
11	Producing Gas Wells-Well Construction	330	18
12	Producing Gas Wells-Well Equipment	331	24
13	Field Lines	332	725
14	Field Measuring & Reg. Station Equipment	334	85
15	Drilling & Cleaning Equipment	335	49
16	Other Equipment	337	11
17	TOTAL PRODUCTION & GATHERING		1,150
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	100
20	Land	350	-
21	Rights of Way	350	(52)
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		48

($ in Thousands)

Accumulated Provision for Depreciation

Line No	Description	[1] Account No	[2] HTY 9-30-21
	TRANSMISSION PLANT		
30	Land & Land Rights	365	-
31	Rights of Way	365	525
32	Structures & Improvements	366	145
33	Mains	367	21,427
34	Measuring & Regulating Station Equipment	369	3,871
35	Communication Equipment	370	2,030
36	Other Equipment	371	276
37	TOTAL TRANSMISSION		28,274
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	1,335
39	Structures & Improvements	375	3,159
40	Mains	376	450,869
41	Measuring & Regulating Station Equipment	378	26,331
42	Measuring & Regulating Station Equipment	379	7,763
43	Services	380	367,843
44	Meters	381	70,891
45	Meter Installations	382	33,971
46	House Regulators	383	5,525
47	House Regulatory Installations	384	8,438
48	Industrial Measuring & Reg. Station Equipment	385	16,637
49	Other Property	386	569
50	Other Equipment	387	4,290
51	TOTAL DISTRIBUTION		997,621
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	40,400
54	Office Furniture & Equipment	391	72,877
55	Transportation Equipment	392	9,545
56	Stores Equipment	393	5
57	Tools & Garage Equipment	394	11,577
58	Laboratory Equipment	395	90
59	Power Operated Equipment	396	1,925
60	Communication Equipment	397	373
61	Miscellaneous Equipment	398	650
62	Other Tangible Property	399	16
63	TOTAL GENERAL		137,458
64	Total Plant		$ 1,164,551

($ in Thousands)

Summary of Accumulated Depreciation

		[1]	[2]	[3]	[4]
		Factor	Test Year Ended September 30, 2021		
Line #	Description	Or Reference	Amount	Pro Forma Adjustment	Balance
1	Intangible Plant	Sch C-3, Pg 4	$ -	-	$ -
2	Natural Gas Production & Gathering	Sch C-3, Pg 4	1,150	-	1,150
3	Natural Gas Storage & Processing Plant	Sch C-3, Pg 4	48	-	48
4	Transmission Plant	Sch C-3, Pg 5	28,274	-	28,274
5	Distribution Plant	Sch C-3, Pg 5	997,621	-	997,621
6	General Plant	Sch C-3, Pg 5	137,458	-	137,458
7	Other Plant		-		-
8	TOTAL ACC DEPR & AMORTIZATION		$ 1,164,551	$ -	$ 1,164,551

($ in Thousands)

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Historic Test Year 2021	[3] Pro Forma Adjustment	[4] Balance
	INTANGIBLE PLANT				
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
	NATURAL GAS PRODUCTION & GATHERING				
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	162	-	162
7	Rights of Way	325.4	30	-	30
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	1	-	1
10	Other Structures	329	45	-	45
11	Producing Gas Wells-Well Construction	330	18	-	18
12	Producing Gas Wells-Well Equipment	331	24	-	24
13	Field Lines	332	725	-	725
14	Field Measuring & Reg. Station Equipment	334	85	-	85
15	Drilling & Cleaning Equipment	335	49	-	49
16	Other Equipment	337	11	-	11
17	TOTAL PRODUCTION & GATHERING		1,150	-	1,150
	NATURAL GAS STORAGE & PROCESSING PLANT				
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	100	-	100
20	Land	350.1	-	-	-
21	Rights of Way	350.2	(52)	-	(52)
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
29	TOTAL STORAGE & PROCESSING		48	-	48

($ in Thousands)

Accumulated Depreciation by FERC Account

Line #	Description	[1] Account Number	[2] Historic Test Year 2021	[3] Pro Forma Adjustment	[4] Balance
	TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-	-
31	Rights of Way	365.2	525	-	525
32	Structures & Improvements	366	145	-	145
33	Mains	367	21,427	-	21,427
34	Measuring & Regulating Station Equipment	369	3,871	-	3,871
35	Communication Equipment	370	2,030	-	2,030
36	Other Equipment	371	276	-	276
37	TOTAL TRANSMISSION		28,274	-	28,274
	DISTRIBUTION PLANT				
38	Land & Land Rights	374	1,335	-	1,335
39	Structures & Improvements	375	3,159	-	3,159
40	Mains	376	450,869	-	450,869
41	Measuring & Regulating Station Equipment	378	26,331	-	26,331
42	Measuring & Regulating Station Equipment	379	7,763	-	7,763
43	Services	380	367,843	-	367,843
44	Meters	381	70,891	-	70,891
45	Meter Installations	382	33,971	-	33,971
46	House Regulators	383	5,525	-	5,525
47	House Regulatory Installations	384	8,438	-	8,438
48	Industrial Measuring & Reg. Station Equipment	385	16,637	-	16,637
49	Other Property	386	569	-	569
50	Other Equipment	387	4,290	-	4,290
51	TOTAL DISTRIBUTION		997,621	-	997,621
	GENERAL PLANT				
52	Land & Land Rights	389	-	-	-
53	Structures & Improvements	390	40,400	-	40,400
54	Office Furniture & Equipment	391	72,877	-	72,877
55	Transportation Equipment	392	9,545	-	9,545
56	Stores Equipment	393	5	-	5
57	Tools & Garage Equipment	394	11,577	-	11,577
58	Laboratory Equipment	395	90	-	90
59	Power Operated Equipment	396	1,925	-	1,925
60	Communication Equipment	397	373	-	373
61	Miscellaneous Equipment	398	650	-	650
62	Other Tangible Property	399	16	-	16
63	TOTAL GENERAL		137,458	-	137,458
64	Total Plant		$ 1,164,551	$ -	$ 1,164,551

($ in Thousands)

Cost of Removal

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		-

($ in Thousands)

Cost of Removal

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	-
33	Mains	367	2
34	Measuring & Regulating Station Equipment	369	3
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		5
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	-
39	Structures & Improvements	375	-
40	Mains	376	2,535
41	Measuring & Regulating Station Equipment	378	169
42	Measuring & Regulating Station Equipment	379	15
43	Services	380	4,191
44	Meters	381	1
45	Meter Installations	382	225
46	House Regulators	383	-
47	House Regulatory Installations	384	14
48	Industrial Measuring & Reg. Station Equipment	385	35
49	Other Property	386	-
50	Other Equipment	387	-
51	TOTAL DISTRIBUTION		7,185
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	-
54	Office Furniture & Equipment	391	-
55	Transportation Equipment	392	-
56	Stores Equipment	393	-
57	Tools & Garage Equipment	394	-
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	-
60	Communication Equipment	397	-
61	Miscellaneous Equipment	398	392
62	Other Tangible Property	399	-
63	TOTAL GENERAL		392
64	Total Plant		$ 7,582

($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	(8)
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	16
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		8

($ in Thousands)

Negative Net Salvage Amortization

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	-
33	Mains	367	-
34	Measuring & Regulating Station Equipment	369	1
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		1
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	-
39	Structures & Improvements	375	7
40	Mains	376	1,559
41	Measuring & Regulating Station Equipment	378	130
42	Measuring & Regulating Station Equipment	379	3
43	Services	380	4,791
44	Meters	381	(2)
45	Meter Installations	382	508
46	House Regulators	383	967
47	House Regulatory Installations	384	106
48	Industrial Measuring & Reg. Station Equipment	385	15
49	Other Property	386	-
50	Other Equipment	387	2
51	TOTAL DISTRIBUTION		8,086
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	35
54	Office Furniture & Equipment	391	-
55	Transportation Equipment	392	(259)
56	Stores Equipment	393	-
57	Tools & Garage Equipment	394	-
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	-
60	Communication Equipment	397	-
61	Miscellaneous Equipment	398	136
62	Other Tangible Property	399	-
63	TOTAL GENERAL		(88)
64	Total Plant		$ 8,007

($ in Thousands)

Salvage

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	INTANGIBLE PLANT		
1	Organization	301	$ -
2	Franchise & Consent	302	-
3	Miscellaneous Intangible Plant	303	-
4	TOTAL INTANGIBLE		-
	NATURAL GAS PRODUCTION & GATHERING		
5	Producing Lands	325.1	-
6	Producing Leaseholds	325.2	-
7	Rights of Way	325.4	-
8	Other Land Rights	325.5	-
9	Field Measuring & Regulating Station Structures	328	-
10	Other Structures	329	-
11	Producing Gas Wells-Well Construction	330	-
12	Producing Gas Wells-Well Equipment	331	-
13	Field Lines	332	-
14	Field Measuring & Reg. Station Equipment	334	-
15	Drilling & Cleaning Equipment	335	-
16	Other Equipment	337	-
17	TOTAL PRODUCTION & GATHERING		-
	NATURAL GAS STORAGE & PROCESSING PLANT		
18	Land & Land Rights	304	-
19	Production Plant-Manufactured Gas Plants	305	(115)
20	Land	350.1	-
21	Rights of Way	350.2	-
22	Structures & Improvements	351	-
23	Wells	352	-
24	Lines	353	-
25	Compressor Station Equipment	354	-
26	Measuring & Regulating Equipment	355	-
27	Purification Equipment	356	-
28	Other Equipment	357	-
29	TOTAL STORAGE & PROCESSING		(115)

($ in Thousands)

Salvage

Line #	Description	[1] Account Number	[2] Historic Test Year 2021
	TRANSMISSION PLANT		
30	Land & Land Rights	365.1	-
31	Rights of Way	365.2	-
32	Structures & Improvements	366	-
33	Mains	367	-
34	Measuring & Regulating Station Equipment	369	-
35	Communication Equipment	370	-
36	Other Equipment	371	-
37	TOTAL TRANSMISSION		-
	DISTRIBUTION PLANT		
38	Land & Land Rights	374	-
39	Structures & Improvements	375	-
40	Mains	376	-
41	Measuring & Regulating Station Equipment	378	-
42	Measuring & Regulating Station Equipment	379	-
43	Services	380	-
44	Meters	381	(19)
45	Meter Installations	382	-
46	House Regulators	383	-
47	House Regulatory Installations	384	-
48	Industrial Measuring & Reg. Station Equipment	385	-
49	Other Property	386	-
50	Other Equipment	387	-
51	TOTAL DISTRIBUTION		(19)
	GENERAL PLANT		
52	Land & Land Rights	389	-
53	Structures & Improvements	390	-
54	Office Furniture & Equipment	391	-
55	Transportation Equipment	392	(527)
56	Stores Equipment	393	-
57	Tools & Garage Equipment	394	-
58	Laboratory Equipment	395	-
59	Power Operated Equipment	396	-
60	Communication Equipment	397	-
61	Miscellaneous Equipment	398	-
62	Other Tangible Property	399	-
63	TOTAL GENERAL		(527)
64	Total Plant		$ (661)

Working Capital

		[1]	[2]
Line No	**Description**	**Historic Year 9/30/2021**	**Reference**
1	Working Capital for O & M Expense	$ 43,470	C-4, Page 2
2	Interest Payments	(4,125)	C-4, Page 7
3	Tax Payment Lag Calculations	3,518	C-4, Page 8
4	Prepaid Expenses	10,047	C-4, Page 9
5	Total Cash Working Capital Requirements	$ 52,911	

($ in Thousands)

Summary of Working Capital

Line #	Description	[1] Reference	[2] Historic Test Year Expenses	[3] Factor	[4] Number of (Lead) / Lag Days [2] * [3]	[5] Totals
	WORKING CAPITAL REQUIREMENT					
1	REVENUE LAG DAYS	Page 3				61.18
2	EXPENSE LAG DAYS	Page 4				
3	Payroll	Sch D-7	$ 71,835	12.00	$ 862,017	
4	Purchased Gas Costs	Sch D-6	331,546	39.85	13,213,600	
5	Other Expenses	L 19 - L 2 to L 4	154,424	27.08	4,181,802	
6	Total	Sum (L 3 to L 5)	$ 557,805		$ 18,257,419	
7	O & M Expense Lag Days	L6, C 4 / C 2				32.73
8	Net (Lead) Lag Days	L 1 - L 7				28.45
9	Operating Expenses Per Day	L 6, C 2 / 365				$ 1,528
10	Working Capital for O & M Expense	L 8 * L 9				$ 43,470
11	Interest Payments	Page 7				(4,125)
12	Tax Payment Lag Calculations	Page 8				3,518
13	Prepaid Expenses	Page 9				10,047
14	Total Working Capital Requirement	Sum (L 10 to L 13)				$ 52,911
15	Pro Forma O & M Expense		$ 571,654			
	Less:					
16	Uncollectible Expense		13,849			
17	Sub-Total		13,849			
18	Pro Forma Cash O&M Expense		$ 557,805			

($ in Thousands)

Revenue Lag

Line No.	Description	[1] Reference Or Factor	[2] Accounts Receivable Balance End of Month		[3] Total Monthly Sales Page 2		[4] A/R Turnover [3] / [2]		[5] Days Lag 365 / [4]
1	Annual Number of Days								365
2	September, 2020		$ 52,950						
3	October		$ 61,679		$ 41,665				
4	November		$ 72,123		$ 55,297				
5	December, 2020		$ 106,368		$ 100,676				
6	January, 2021		$ 140,439		$ 126,612				
7	February		$ 164,061		$ 130,900				
8	March		$ 153,427		$ 128,921				
9	April		$ 133,479		$ 74,513				
10	May		$ 116,982		$ 48,952				
11	June		$ 100,284		$ 39,572				
12	July		$ 87,161		$ 31,323				
13	August		$ 76,062		$ 33,489				
14	September, 2021		$ 62,224		$ 32,352				
15	Total	Sum L 2 to L 14	$1,327,239						
16	Number of Months	13							
17	Average Acct Rec Balance	L 15 / L 16	$102,095						
18	Total Sales for Year	Sum L 2 to L 14			$ 844,272				
19	Acct Rec Turnover Ratio	L 18 / L 17					8.27		
20	Collection Lag Day Factor	L 1 / L 19							44.14
21	Meter Read Lag Factor								1.83
22	Midpoint Lag Factor		365	/	12	/	2	=	15.21
23	Total Revenue Lag Days	Sum L 20 to L 22							**61.18**

($ in Thousands)

Summary of Expense Lag Calculations

Line No.	Description	Reference Or Factor [1]	Historic Test Year Amount [2]	(Lead) / Lag Days [3]	Weighted Dollar Value [4] [2] * [3]	(Lead) / Lag Days [5] [4] / [2]
	PAYROLL					
1	Union Payrolls	Bi-Weekly	$ 28,880	12.00		
2	Exempt & Non-Exempt	Bi-Weekly	42,955	12.00		
3	Weighted for Union	L1, C2 * C3			$ 346,561	
4	Weighted for Other	L2, C2 * C3			515,454	
5	Payroll Lag	L 3 + L 4	$ 71,835		$ 862,015	
6	Payroll Lag Days	C 4 / C 2				12.00
	PURCHASE GAS COSTS					
7	Payment Lag	Page 6	$ 374,258		$ 14,915,898	
8	Gas Cost Lag Days	C 4 / C 2				39.85
	OTHER O & M EXPENSES					
9	OCTOBER 2020	Page 5	$ 13,011		$ 464,688	
10	NOVEMBER 2020	Page 5	12,267		354,754	
11	DECEMBER 2020	Page 5	10,704		296,691	
12	JANUARY 2021	Page 5	13,154		403,634	
13	FEBRUARY 2021	Page 5	9,535		296,050	
14	MARCH 2021	Page 5	15,795		392,990	
15	APRIL 2021	Page 5	8,487		212,723	
16	MAY 2021	Page 5	11,246		236,159	
17	JUNE 2021	Page 5	13,342		293,544	
18	JULY 2021	Page 5	10,212		305,230	
19	AUGUST 2021	Page 5	11,697		290,457	
20	SEPTEMBER 2021	Page 5	13,828		332,536	
21	TOTAL		$ 143,277		$ 3,879,457	
22	Other O&M Expense Lag Days	L21, C 4 / C 2				27.08

($ in Thousands)

General Disbursements Payment Lag Summary

Line #	Description	[1] Number of CDs	[2] Cash Disbursements	[3] Dollar-Days	[4] Expense Lag-Days [3] / [2]
	OCTOBER 2020				
1	Total Disbursements for Month	32,992	$ 57,092		
2	Total Disbursements for Expenses	5,068	$ 13,011	$ 464,688	35.72
	NOVEMBER 2020				
3	Total Disbursements for Month	21,713	$ 41,983		
4	Total Disbursements for Expenses	4,909	$ 12,267	$ 354,754	28.92
	DECEMBER 2020				
5	Total Disbursements for Month	21,745	$ 31,881		
6	Total Disbursements for Expenses	4,741	$ 10,704	$ 296,691	27.72
	JANUARY 2021				
7	Total Disbursements for Month	22,708	$ 37,776		
8	Total Disbursements for Expenses	4,488	$ 13,154	$ 403,634	30.68
	FEBRUARY 2021				
9	Total Disbursements for Month	19,680	$ 29,480		
10	Total Disbursements for Expenses	4,120	$ 9,535	$ 296,050	31.05
	MARCH 2021				
11	Total Disbursements for Month	16,472	$ 34,931		
12	Total Disbursements for Expenses	4,961	$ 15,795	$ 392,990	24.88
	APRIL 2021				
13	Total Disbursements for Month	25,582	$ 30,669		
14	Total Disbursements for Expenses	4,614	$ 8,487	$ 212,723	25.06
	MAY 2021				
15	Total Disbursements for Month	28,733	$ 34,180		
16	Total Disbursements for Expenses	4,800	$ 11,246	$ 236,159	21.00
	JUNE 2021				
17	Total Disbursements for Month	33,951	$ 49,835		
18	Total Disbursements for Expenses	5,546	$ 13,342	$ 293,544	22.00
	JULY 2021				
19	Total Disbursements for Month	31,356	$ 42,313		
20	Total Disbursements for Expenses	5,502	$ 10,212	$ 305,230	29.89
	AUGUST 2021				
21	Total Disbursements for Month	30,804	$ 37,118		
22	Total Disbursements for Expenses	5,756	$ 11,697	$ 290,457	24.83
	SEPTEMBER 2021				
23	Total Disbursements for Month	36,824	$ 55,311		
24	Total Disbursements for Expenses	5,645	$ 13,828	$ 332,536	24.05
25	Total Test Month Expense Disbursement	60,150	$ 143,277	$ 3,879,457	27.08

Purchase Gas Cost Payment Lag Summary

		[1]	[2]	[3]	[4]
Line #	Description	Number of Invoices	Amount of Invoice	Dollar Days	Total Payment Lag-Days
1	October 2020	28	$ 11,709	$ 418,248	35.72
2	November	38	35,682	1,031,745	28.92
3	December	28	30,793	1,407,814	45.72
4	January 2021	38	54,079	2,588,442	47.86
5	February	34	53,409	2,165,844	40.55
6	March	28	52,465	2,037,549	38.84
7	April	27	24,904	1,006,441	40.41
8	May	37	23,869	887,286	37.17
9	June	28	19,244	729,594	37.91
10	July	27	19,573	757,275	38.69
11	August	27	23,147	911,332	39.37
12	Septermber 2021	28	25,384	974,330	38.38
13	Total		$ 374,258	$ 14,915,898	
14	Purchase Gas Lag Days				39.85

Interest Payments

Line No.	Description	[1] Reference Or Factor	[2] # of Days	[3] # of Days	[4] Total
1	Measure of Value at September 30, 2021	Sch C-1			$ 2,545,603
2	Long-term Debt Ratio	Sch B-6			47.40%
3	Embedded Cost of Long-term Debt	Sch B-6			4.15%
4	Pro forma Interest Expense	L 1 * L 2 * L 3			$ 50,075
5	Daily Amount	L 4 / L 5 [2]	365		$ 137
6	Days to mid-point of interest payments			91.25	
7	Less: Revenue Lag Days	Page 3		61.18	
8	Interest Payment lag days	L 7 - L 6			(30.1)
9	Total Interest for Working Capital	L 5 * L 8			$ (4,125)

Tax Lag Day Calculations

Line #	Description	[1] Payment Dates	[2] Mid-Point of Service Period	[3] Lead (Lag) Payment Days [1] - [2]	[4] Payment Amount	[5] Weighted Lead (Lag) Dollars [3] * [4]	[6] Payment Lead (Lag) Days [5] / [4]	[7] Revenue (Lag) Days	[8] Net Payment Lead (Lag) Days [6] - [7]	[9] Total Dollar Days	[10] Working Capital Amount
											365
1	**FEDERAL INCOME TAX**				$ 35,037						
2	First Payment	01/05/21	04/01/21	86.00	$ 8,759	753,289					
3	Second Payment	03/15/21	04/01/21	17.00	8,759	148,906					
4	Third Payment	06/15/21	04/01/21	(75.00)	8,759	(656,938)					
5	Fourth Payment	09/15/21	04/01/21	(167.00)	8,759	(1,462,782)					
6	Total				$ 35,037	$ (1,217,525)	(34.75)	(61.18)	26.43	$ 926,020	$ 2,537
7	**STATE INCOME TAX**				$ 11,123						
8	First Payment	12/15/20	04/01/21	107.00	$ 2,781	297,536					
9	Second Payment	03/15/21	04/01/21	17.00	2,781	47,272					
10	Third Payment	06/15/21	04/01/21	(75.00)	2,781	(208,553)					
11	Fourth Payment	09/15/21	04/01/21	(167.00)	2,781	(464,378)					
12	Total				$ 11,123	(328,123)	(29.50)	(61.18)	31.68	$ 352,371	$ 965
13	**PA PROPERTY TAX**				$ 619						
14	First Payment	03/31/21	04/01/21	1.00	$ 310	310					
15	Second Payment	09/30/21	04/01/21	(182.00)	310	(56,329)					
16	Total				$ 619	(56,020)	(90.50)	(61.18)	(29.32)	$ (18,149)	$ (50)
17	**PURTA**				$ 767						
18	Payment	05/01/21	04/01/21	(30.00)	$ 767	(23,010)	(30.00)	(61.18)	31.18	$ 23,915	$ 66
19	Total Working Capital For Other Taxes										$ 3,518

Prepaid Expenses

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Line #	Description		TOTAL	Insurance	PUC Assessment	Miscellaneous	Subscriptions	Postage	Rent	Maintenance & Services
1	September, 2020		10,751	3,791	2,112	436	52	9	-	4,351
2	October		10,488	3,343	1,877	540	121	11	-	4,596
3	November		10,472	2,908	1,642	1,325	104	6	-	4,487
4	December, 2020		12,689	2,485	1,408	4,609	36	1	-	4,150
5	January, 2021		13,645	2,165	1,173	4,309	152	-	-	5,846
6	February		11,191	1,724	939	1,773	112	4	-	6,639
7	March		8,617	1,308	704	541	174	5	-	5,885
8	April		7,566	1,253	469	455	215	2	-	5,172
9	May		6,575	935	235	405	187	1	-	4,812
10	June		5,399	496	-	329	129	2	-	4,443
11	July		10,518	5,218	-	275	192	2	-	4,831
12	August		10,558	4,880	-	285	65	2	-	5,326
13	September, 2021		12,147	4,370	2,636	296	51	-	-	4,794
14	TOTAL		$ 130,616	$ 34,876	$ 13,195	$ 15,578	$ 1,590	$ 45	$ -	$ 65,332
15	Percent to Gas			100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
16	Amount to Gas			$ 34,876	$ 13,195	$ 15,578	$ 1,590	$ 45	$ -	$ 65,332
17	Monthly Average	13		$ 2,683	$ 1,015	$ 1,198	$ 122	$ 3	$ -	$ 5,026
18	Rate Case Amount		$ 10,047							

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Schedule C-5
Witness: V. K. Ressler

Gas Inventory

Line No.	Description	[1] Stored Underground
1	September, 2020	$ 19,873
2	October	23,542
3	November	23,202
4	December, 2020	18,952
5	January, 2021	12,597
6	February	6,238
7	March	2,560
8	April	5,494
9	May	9,583
10	June	15,888
11	July	23,011
12	August	31,104
13	September, 2021	39,519
14	Total	$ 231,563
15	Number of Months	13
16	Average Monthly Balance	$ 17,813

($ in Thousands)

Accumulated Deferred Income Taxes

Line #	Description	[1] Amount	[2] Total
	Accumulated Deferred Income Tax		
1	Gas Utility Plant - a/c # 282	$ (500,536)	
2	Sub-total		(500,536)
3	ADIT on CIAC	27,644	
4	ADIT for Repairs Tax Deduction	(99,323)	
5	Sub-total		(71,679)
6	Federal ADIT		(572,215)
7	State Repair Regulatory Liability	(29,490)	(29,490)
8	Pro-Rata Adjustment		-
9	Balance At September 30, 2021		$ (601,705)

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Schedule C-7
Witness: V. K. Ressler

Customer Deposits

Line #	Description	[1] Balance At End Of Month
1	September, 2020	$ 22,386
2	October	$ 22,373
3	November	$ 22,331
4	December, 2020	$ 22,118
5	January, 2021	$ 21,930
6	February	$ 21,816
7	March	$ 21,634
8	April	$ 21,386
9	May	$ 21,040
10	June	$ 20,863
11	July	$ 20,873
12	August	$ 20,930
13	September, 2021	$ 21,120
14	Total	$ 280,800
15	Number of Months	13
16	Average Monthly Balance	$ 21,600

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Materials & Supplies

Line #	Month	[1] Materials & Supplies
1	September, 2020	$ 16,650
2	October	15,001
3	November	15,305
4	December, 2020	16,991
5	January, 2021	14,991
6	February	15,280
7	March	16,617
8	April	15,546
9	May	15,493
10	June	16,341
11	July	15,493
12	August	15,376
13	September, 2021	15,108
14	Total	$ 204,192
15	Number of Months	13
16	Average Monthly Balance	$ 15,707

($ in Thousands)

Summary of Revenue and Expenses
Pro Forma with Proposed Revenue Increase

Line #	Description	Factor Or Reference	[1] Pro Forma Test Year At Present Rates	[2] Rate Increase	[3] At Proposed Rates
	OPERATING REVENUES				
1	Customer & Distribution Revenue		$ 580,252	$ -	$ 580,252
2	Gas Supply & Cost Adjustment Revenue		363,751	-	363,751
3	Other Revenues		11,634	-	11,634
4	Revenue Increase			(20,397)	(20,397)
5	Total operating revenues		955,637	(20,397)	935,240
	OPERATING EXPENSES				
6	Manufactured Gas		29	-	29
7	Gas Supply Production		331,546	-	331,546
8	Transmission		-		
9	Distribution		64,120	-	64,120
10	Customer Accounts		41,533	-	41,533
11	Uncollectible Expense	1.647%	13,849	(336)	13,513
12	Customer Information & Services		10,283	-	10,283
13	Sales		2,071	-	2,071
14	Administrative & General		108,222	-	108,222
15	Depreciation & Amortization		108,913	-	108,913
16	Taxes other than income taxes		8,765	-	8,765
17	Total operating expenses		689,332	(336)	688,996
18	Net operating income Before Income Tax		266,305	(20,061)	246,244
	Income Taxes				
19	Pro Forma Income Tax At Present Rates		51,956		51,956
20	Pro Forma Income Tax on Revenue Increase			(5,796)	(5,796)
21	Net Income (loss)		$ 214,349	$ (14,265)	$ 200,084

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Schedule D-2
Witness: T. A. Hazenstab
Page 1 of 1

Summary of Pro Forma Revenue and Expense
Adjustments with Proposed Revenue Increase

Line #	Description	[1] Factor Or Reference	[2] Test Year At Present Rates: Actual For Year End 09/30/21	[3] Test Year At Present Rates: Adjustments Sch D-3 Increase (Decrease)	[4] Test Year At Present Rates: Pro Forma Adjusted For Test Year 9/30/21	[5] Proposed Increase	[6] Pro Forma Test Year With Proposed Increase
	OPERATING REVENUES			-	[2] + [3]		[4] + [5]
1	Residential (R/RT)	480	$ 506,222	$ 67,811	$ 574,033		$ 574,033
2	Comm & Ind (N/NT)	481	190,495	25,729	216,224		216,224
3	Comm & Ind (DS)	489	46,750	5,854	52,604		52,604
4	Lg Transport/Other	489	75,823	1,047	76,870		76,870
5	Interruptible	489	24,920	(648)	24,272		24,272
6	Forfeited Discounts		4,882	-	4,882		4,882
7	Miscellaneous Service Revenues		4,469	-	4,469		4,469
8	Rent from Gas Properties		2,283	-	2,283		2,283
9	Rate Increase			-	-	(20,397)	(20,397)
10	Total operating revenues		855,844	99,793	955,637	(20,397)	935,240
	OPERATING EXPENSES						
11	Gas Production		29	-	29		29
12	Gas Supply Production		262,475	69,071	331,546		331,546
13	Transmission		-		-		
14	Distribution		63,696	424	64,120		64,120
15	Customer Accounts		41,338	195	41,533		41,533
16	Uncollectible Expense	1.647%	11,927	1,922	13,849	(336)	13,513
17	Customer Information & Services		10,266	17	10,283		10,283
18	Sales		2,061	10	2,071		2,071
19	Administrative & General		107,811	411	108,222		108,222
20	Depreciation & Amortization		109,080	(167)	108,913		108,913
21	Taxes other than income taxes		8,707	58	8,765		8,765
22	Total operating expenses		617,390	71,942	689,332	(336)	688,996
23	Net Operating Income - BIT		$ 238,454	$ 27,851	$ 266,305	$ (20,061)	$ 246,244

($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description		[1] As Actual And Allocated	[2] D-4	[3] Revenues D-5	[4] Gas Costs D-6	[5] Salaries & Wages D-7	[6] D-8	[7] D-9	[8] D-10	[9] Uncollectibles Expense D-11	[10] D-12	[11] D-13	[12] Sub-Total Adjustments	[13] Total Proforma
					Adjustments										
	OPERATING REVENUES														
	Customer & Distribution Revenue														
1	Residential (R/RT)	480	$ 304,767		$ 13,854									$ 13,854	$ 318,621
2	Comm & Ind (N/NT)	481	121,244		6,757									6,757	128,001
3	Comm & Ind (DS)	489	29,732		5,732									5,732	35,464
4	Lg Transport/Other	489	73,604		1,040									1,040	74,644
5	Interruptible	489	24,170		(648)									(648)	23,522
	Revenue for Cost of Gas													-	-
6	Residential (R/RT)	480	201,455		53,957									53,957	255,412
7	Comm & Ind (N/NT)	481	69,251		18,972									18,972	88,223
8	Comm & Ind (DS)	489	17,018		122									122	17,140
9	Lg Transport/Other	489	2,219		7									7	2,226
10	Interruptible Transport	489	750		-									-	750
11	Forfeited Discounts		4,882		-									-	4,882
12	Miscellaneous Service Revenues		4,469		-									-	4,469
13	Rent from Gas Properties		2,283		-									-	2,283
14	Rate Increase		-											-	-
15	Total operating revenues		855,844		99,793	-	-	-	-	-	-	-	-	99,793	955,637
	OPERATING EXPENSES														-
16	Gas Production		29											-	29
17	Gas Supply Production		262,475			69,071								69,071	331,546
18	Transmission		-												-
19	Distribution		63,696				424							424	64,120
20	Customer Accounts		41,338				195							195	41,533
21	Uncollectible Expense		11,927								1,922			1,922	13,849
22	Customer Information & Services		10,266				17							17	10,283
23	Sales		2,061				10							10	2,071
24	Administrative & General		107,811				411							411	108,222
25	Depreciation & Amortization		109,080											-	109,080
26	Taxes other than income taxes		8,707											-	8,707
														-	-
27	Total operating expenses		$ 617,390	$ -	$ -	$ 69,071	$ 1,058	$ -	$ -	$ -	$ 1,922	$ -	$ -	$ 72,051	$ 689,441
28	Net operating income Before Income Tax		$ 238,454	$ -	$ 99,793	$ (69,071)	$ (1,058)	$ -	$ -	$ -	$ (1,922)	$ -	$ -	$ 27,742	$ 266,196

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Summary of Pro Forma Adjustments

Line #	Description	[1] From Page 1 Sub-total	[2]	[3] Adjustments D-14	[4] D-15	[5] D-16	[6] D-17	[7] D-18	[8] D-19	[9]	[10] Depreciation D-21	[11] Taxes Other Than Income D-31	[12]	[13] TOTAL Adjusted
	OPERATING REVENUES													
29	**Customer & Distribution Revenue**													
30	Residential (R/RT)	$ 318,621												$ 318,621
31	Comm & Ind (N/NT)	128,001												128,001
32	Comm & Ind (DS)	35,464												35,464
33	Lg Transport/Other	74,644												74,644
34	Interruptible	23,522												23,522
	Revenue for Cost of Gas													-
35	Residential (R/RT)	255,412												255,412
36	Comm & Ind (N/NT)	88,223												88,223
37	Comm & Ind (DS)	17,140												17,140
38	Lg Transport/Other	2,226												2,226
39	Interruptible Transport	750												750
40	Forfeited Discounts	4,882												4,882
41	Miscellaneous Service Revenues	4,469												4,469
42	Rent from Gas Properties	2,283												2,283
43	Rate Increase	-												-
44	Total operating revenues	955,637	-	-	-	-	-	-	-	-	-	-	-	955,637
	OPERATING EXPENSES													
45	Gas Production	29												29
46	Gas Supply Production	331,546												331,546
47	Transmission	-												-
48	Distribution	64,120												64,120
49	Customer Accounts	41,533												41,533
50	Uncollectible Expense	13,849												13,849
51	Customer Information & Services	10,283												10,283
52	Sales	2,071												2,071
53	Administrative & General	108,222												108,222
54	Depreciation & Amortization	109,080									(167)			108,913
55	Taxes other than income taxes	8,707										58		8,765
56	Total operating expenses	$ 689,441	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (167)	$ 58	$ -	$ 689,332
57	Net operating income Before Income Tax	$ 266,196	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 167	$ (58)	$ -	$ 266,305

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment - Revenue Adjustments

		[1]	[2]	[3]	[4]	[5]	[6]
				PRO FORMA ADJUSTMENTS			
Line #	Description	Reference Or Account Number	2021 Actual	Other Adjustments	Rev/PGC Adj Annualization	Total Proforma Adjustments	Proforma Adjusted At Present Rates
						D-5A	
	Customer & Distribution Revenue						
1	Residential (R/RT)	480	$ 304,767	$ 13,854		$ 13,854	$ 318,621
2	Comm & Ind (N/NT)	481	121,244	6,757		6,757	128,001
3	Comm & Ind (DS)	489	29,732	5,732		5,732	35,464
4	Lg Transport/Other	489	73,604	1,040		1,040	74,644
5	Interruptible	489	24,170	(648)		(648)	23,522
6	Cust Chg & Distrib Revenue		553,517	26,735	-	26,735	580,252
	Revenue for Cost of Gas						
7	Residential (R/RT)	480	201,455	4,043	49,914	53,957	255,412
8	Comm & Ind (N/NT)	481	69,251	(185)	19,157	18,972	88,223
9	Comm & Ind (DS)	489	17,018	122		122	17,140
10	Lg Transport/Other	489	2,219	7		7	2,226
11	Interruptible Transport	489	750	-		-	750
12	Revenue for Cost of Gas		290,693	3,987	69,071	73,058	363,751
							-
13	Total Customer Revenue		844,210	30,722	69,071	99,793	944,003
14	Forfeited Discounts	487	4,882		-	-	4,882
15	Miscellaneous Service Revenues	488	1,277		-	-	1,277
							-
16	Rent from Gas Properties	493	2,283		-	-	2,283
17	Other Revenues	495	3,192			-	3,192
18	TOTAL REVENUES		$ 855,844	$ 30,722	$ 69,071	$ 99,793	$ 955,637

($ in Thousands)

Adjustment - Test Year Revenue Changes

Line #	Description	[1] Factor Or Reference	[2] 2021 Actual	[3] Revised Actual	[4] Adjustment [3] - [2]	[5] Total Adjustment
TOTAL REVENUE						
1	Residential (R/RT)		$ 506,222	$ 574,033	$ 67,811	
2	Comm & Ind (N/NT)		190,495	216,224	25,729	
3	Comm & Ind (DS)		46,750	52,604	5,854	
4	Lg Transport/Other		75,823	76,870	1,047	
5	Interruptible		24,920	24,271	(649)	
6	Total		$ 844,210	$ 944,002	$ 99,792	$ 99,792
COST OF COMMODITY						
7	Residential (R/RT)		$ 201,454	$ 255,411	$ 53,957	
8	Comm & Ind (N/NT)		69,251	88,223	18,972	
9	Comm & Ind (DS)		17,018	17,140	122	
10	Lg Transport/Other		2,219	2,226	7	
11	Interruptible		750	749	(1)	
12	Total		$ 290,692	$ 363,749	$ 73,057	$ 73,057
NET CUSTOMER & DISTRIBUTION						
13	Residential (R/RT)		$ 304,768	$ 318,622	$ 13,854	
14	Comm & Ind (N/NT)		121,244	128,001	6,757	
15	Comm & Ind (DS)		29,732	35,464	5,732	
16	Lg Transport/Other		73,604	74,644	1,040	
17	Interruptible		24,170	23,522	(648)	
18	Total		$ 553,518	$ 580,253	$ 26,735	$ 26,735

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment - Gas Costs

		[1]	[2]	[3]	[4]	[5]
			PRO FORMA ADJUSTMENTS			
Line #	Description	Actual Gas Costs	D-5A Gas Costs		Gas Cost Pro Forma Adjustments	Pro Forma Gas Costs At Present Rates
1	Budgeted Gas Costs	$ 262,475			$ -	$ 262,475
2	Residential (R/RT)		49,914		49,914	49,914
3	Comm & Ind (N/NT)		19,157		19,157	19,157
4	Comm & Ind (DS)		-		-	-
5	Lg Transport/Other		-		-	-
6	Interruptible		-		-	-
7	**Total Gas Costs**	$ 262,475	$ 69,071	$ -	$ 69,071	$ 331,546

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Schedule D-7
Witness: T. A. Hazenstab

Adjustment - Salaries & Wages

Line #	Description	[1] Recorded Year 09/30/21	[2] Adjustment	[3] Payroll As Distributed	[4] Annualization Adjustment	[5] Total Pro Forma Payroll
	OPERATIONS					
1	Total Natural Gas Production Expenses	$ -	$ -	$ -	$ -	$ -
2	Total Underground Storage Expenses	(31)	-	(31)	-	(31)
3	Total Transmission Operation Expenses	-	-	-	-	-
4	Total Distribution Operation Expenses	23,002	-	23,002	344	23,346
5	Customer Account Operations Expenses	13,068	-	13,068	195	13,263
6	Total Cust. Service & Inform. Operations Exp	1,159	-	1,159	17	1,176
7	Total Operation Sales Expenses	662	-	662	10	672
8	Total A & G Operation Expenses	26,154	-	26,154	391	26,545
9	Total Operations	64,014	-	64,014	957	64,971
	MAINTENANCE					
10	Total Underground Maintenance Expenses	-	-	-	-	-
11	Storage Maintenance Expenses	-	-	-	-	-
12	Total Transmission Maintenance Expenses	-	-	-	-	-
13	Total Distribution Maintenance Expenses	5,407	-	5,407	81	5,488
14	Total A&G Maintenance	1,356	-	1,356	20	1,376
15	Total Maintenance	6,763	-	6,763	101	6,864
16	Total Payroll to Expense	$ 70,777	$ -	$ 70,777	$ 1,058	$ 71,835
17	Percent Increase					1.494%

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment - Salaries & Wages

		[1]	[2]	[3]	[4]	[5]
Line #	Description	Reference Or Function	Union At 6-1	Non-Exempt	Exempt	Pro Forma Total Payroll
1	Actual Payroll For TY 9-30-21		$ 28,311	$ 27,603	$ 14,863	$ 70,777
	Annualize for Wage Increase to 9-30-21					
2	Percent Increase		3.00%	3.00%	3.00%	
3	Union Increase At 6/1 Annualization Factor	6/1/21	67%			
4	Non-Exempt Annualization Factor	4/1/21		50%		
5	Exempt Annualization Factor	12/1/19			17%	
6	Increase for wage rate changes	L 1 * L 2 * Ls 3 to 5	569	414	74	$ 1,058
7	Annualized Salaries & Wages at 9-30-21 Rates	L 1 + L 6	$ 28,880	$ 28,017	$ 14,937	
8	Annualization of D-9 changes FY2021					
9	Pro Forma Salaries & Wages for TY		$ 28,880	$ 28,017	$ 14,937	
10	Pro Forma Adjustment to S&W					$ 1,058
11	Annualization Factor	L 11 / L 1				1.494%

($ in Thousands)

Adjustment - Uncollectibles

Line #	Description	[1] Reference Or Factor	[2] Uncollectible Expense	[3] Tariff Revenue	[4] Percent [2] / [3]	[5] Total [2] / [3]
1	2019		$ 14,400	$ 836,206	1.72%	
2	2020		$ 13,417	$ 837,568	1.60%	
3	2021		$ 13,706	$ 847,722	1.62%	
4	Three Year Average Sum (Line 1 to Line 3) / 3	3	$ 13,841	$ 840,499		1.647%
5	2021 Recorded				$ 13,706	
	Pro Forma Adjustment					
6	Adjusted Revenues	1.647%		$ 948,885		
7	Pro Forma at Present Rate Revenue	[1] * [3]			15,628	
8	Total for Test Year					$ 1,922

($ in Thousands)

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Actual 9/30/21 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
INTANGIBLE PLANT					
1	Organization	301	$ -	$ -	$ -
2	Franchise & Consent	302	-	-	-
3	Miscellaneous Intangible Plant	303	-	-	-
4	TOTAL INTANGIBLE		-	-	-
NATURAL GAS PRODUCTION & GATHERING					
5	Producing Lands	325.1	-	-	-
6	Producing Leaseholds	325.2	-	-	-
7	Rights of Way	325.4	-	-	-
8	Other Land Rights	325.5	-	-	-
9	Field Measuring & Regulating Station Structures	328	-	-	-
10	Other Structures	329	-	-	-
11	Producing Gas Wells-Well Construction	330	-	-	-
12	Producing Gas Wells-Well Equipment	331	-	-	-
13	Field Lines	332	1	-	1
14	Field Measuring & Reg. Station Equipment	334	4	(3)	1
15	Drilling & Cleaning Equipment	335	-	-	-
16	Other Equipment	337	-	-	-
			-	-	-
17	TOTAL PRODUCTION & GATHERING		5	(3)	2
NATURAL GAS STORAGE & PROCESSING PLANT					
18	Land & Land Rights	304	-	-	-
19	Production Plant-Manufactured Gas Plants	305	-	-	-
20	Land	350.1	-	-	-
21	Rights of Way	350.2	-	-	-
22	Structures & Improvements	351	-	-	-
23	Wells	352	-	-	-
24	Lines	353	-	-	-
25	Compressor Station Equipment	354	-	-	-
26	Measuring & Regulating Equipment	355	-	-	-
27	Purification Equipment	356	-	-	-
28	Other Equipment	357	-	-	-
					-
29	TOTAL STORAGE & PROCESSING		-	-	-

($ in Thousands)

Adjustment - Depreciation expense

Line #	Description	[1] Account Number	[2] Actual 9/30/21 Depreciation Expense	[3] Adjustment To Annualize At New Depre Study Rates	[4] Pro Forma Test Year Depreciation
	TRANSMISSION PLANT				
30	Land & Land Rights	365.1	-	-	-
31	Rights of Way	365.2	12	-	12
32	Structures & Improvements	366	6	(5)	1
33	Mains	367	460	(1)	459
34	Measuring & Regulating Station Equipment	369	100	(6)	94
35	Communication Equipment	370	127	(16)	111
36	Other Equipment	371	7	(1)	6
37	TOTAL TRANSMISSION		712	(29)	683
	DISTRIBUTION PLANT				
38	Land & Land Rights	374	46	-	46
39	Structures & Improvements	375	88	2	90
40	Mains	376	28,954	2,564	31,518
41	Measuring & Regulating Station Equipment	378	3,030	333	3,363
42	Measuring & Regulating Station Equipment	379	604	40	644
43	Services	380	31,850	1,319	33,169
44	Meters	381	5,348	(94)	5,254
45	Meter Installations	382	2,355	10	2,365
46	House Regulators	383	356	(140)	216
47	House Regulatory Installations	384	375	11	386
48	Industrial Measuring & Reg. Station Equipment	385	838	24	862
49	Other Property	386	23	2	25
50	Other Equipment	387	115	(5)	110
51	TOTAL DISTRIBUTION		73,982	4,066	78,048
	GENERAL PLANT				
52	Land & Land Rights	389	-	-	-
53	Structures & Improvements	390	4,175	(412)	3,763
54	Office Furniture & Equipment	391	20,396	(2,257)	18,139
55	Transportation Equipment	392	3,294	88	3,382
56	Stores Equipment	393	1	-	1
57	Tools & Garage Equipment	394	1,778	56	1,834
58	Laboratory Equipment	395	22	-	22
59	Power Operated Equipment	396	478	14	492
60	Communication Equipment	397	87	27	114
61	Miscellaneous Equipment	398	136	112	248
62	Other Tangible Property	399	-		-
63	TOTAL GENERAL		30,367	(2,372)	27,995
64	TOTAL DEPRECIATION		$ 105,066	$ 1,662	$ 106,728
65	CHARGED TO CLEARING ACCOUNTS		$ (5,637)	$ (185)	$ (5,822)
66	NET SALVAGE AMORTIZATION		$ 9,035	$ (1,028)	$ 8,007

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Adjustment - Taxes Other Than Income Taxes

Line #	Description	[1] Account Number	[2] Factor or Reference	[3] Actual Amounts 9/30/21	[4] Pro Forma Adjustments	[5] Pro Forma Tax Expense 9/30/21
1	PURTA Taxes	408.1		$ 767	$ -	$ 767
2	Capital Stock	408.1		-		-
3	PA & Local Use taxes	408.1		619	-	619
4	Social Security	408.1	D-32	3,614	54	3,668
5	FUTA	408.1	D-32	74	1	75
6	SUTA	408.1	D-32	173	3	176
7	PUC Assessment	408.1		3,460	-	3,460
8	Total			$ 8,707	$ 58	$ 8,765

($ in Thousands)

Adjustment - Payroll Taxes

Line #	Description	[1] Account Number	[2] Actual 9/30/21 Present Rates	[3] Pro Forma Adjustments	[4] Increase in Payroll Taxes
1	Total Payroll Charged to Expense		$ 70,777	$ 1,058	
2	FICA Expense		3,614		
3	FICA Expense - Percent	L 2 / L 1	5.11%	5.11%	
4	Pro Forma FICA Expense on Pro Forma S&W	[4] L 1 * L 3			$ 54
5	FUTA Expense		74		
6	FUTA Expense - Percent	L 5 / L 1	0.10%	0.10%	
7	Pro Forma FUTA Expense on Pro Forma S&W	[4] L 1 * L 6			1
8	SUTA Expense		173		
9	SUTA Expense - Percent	L 8 / L 1	0.24%	0.24%	
10	Pro Forma SUTA Expense on Pro Forma S&W	[4] L 1 * L 9			3
11	Pro Forma Adjustment	Sum L 4 to L 10			$ 58

UGI Utilities, Inc. - Gas Division
Before the Pennsylvania Public Utility Commission
Historic Period - 12 Months Ended September 30, 2021
($ in Thousands)

Income Tax Calculation

Line #	Description	[1] Factor Or Reference	[2] Element Or Amount	[3] Pro Forma Test Year At Present Rates	[4] Revenue Increase	[5] Pro Forma Test Year At Proposed Rates
						[3] + [4]
1	Revenue			$ 955,637	$ (20,397)	$ 935,240
2	Operating Expenses			(689,332)	336	(688,996)
3	OIBIT	L 1 + L 2		266,305	(20,061)	246,244
	Interest Expense					
4	Rate Base	Sch A-1	2,545,603			
5	Weighted Cost of Debt	Sch B-7	0.01970			
6	Synchronized Interest Expense	L 4 * L 5		(50,148)	-	(50,148)
7	Base Taxable Income	L 3 + L 6		216,157	(20,061)	196,096
8	Total Tax Depreciation	Sch D-34	$ 218,095			
9	Pro Forma Book Depreciation	Sch D-34	112,488			
10	State Tax Depreciation (Over) Under Book	L 9 - L 8		(105,607)		(105,607)
11	Other				-	-
12	State Taxable Income	Sum L 7 to L 11		$ 110,550	$ (20,061)	$ 90,489
13	State Income Tax (Expense)/Refund	L 12 * Rate [2]	9.99%	$ (11,044)	$ 2,004	$ (9,040)
14	Total Tax Depreciation	Sch D-34	$ 190,012			
15	Pro Forma Book Depreciation	Sch D-34	112,488			
16	Federal Tax Deducts (Over) Under Book	L 14 - L 13		(77,524)	-	(77,524)
17	Other				-	-
18	Federal Taxable Income	L 7 + sum L 13 to L 17		127,589	(18,057)	109,532
19	Federal Income Tax (Expense)/Refund	-L 18 * Rate [2]	21.00%	(26,794)	3,792	(23,002)
20	Total Tax Expense before Deferred Income Tax	L 13 + L 19		(37,838)	5,796	(32,042)
	Deferred Federal Income Taxes					
21	Total Straight Line Tax Depreciation	Sch D-34	$ 106,728			
22	Total Tax Depreciation	Sch D-34	183,069			
23	Federal Tax Deducts (Over) Under Book	L 22 - L 21		76,341	-	76,341
24	Deferred Federal Taxable Income	L 23		$ 76,341	$ -	$ 76,341
25	Federal Income Tax (Expense)/Refund	-L 24 * Rate [2]	Blended Rate [1]	(12,366)	-	(12,366)
	Deferred State Income Taxes					
26	Repairs			(3,052)		(3,052)
27	CIAC			969		969
28	State Deferred Income Tax (Expense)/Refund			(2,083)	-	(2,083)
29	Net Income Tax Expense	L20 + L 25 + L28		(52,287)	5,796	(46,491)
	Other Tax Adjustments					
30	ITC			331		331
31	Combined Income Tax Expense	L 29 + L 30		$ (51,956)	$ 5,796	$ (46,160)
32	Federal Income Tax Expense	L 19 + L 25 + L 30		$ (38,829)	$ 3,792	$ (35,037)
33	State Income Tax Expense	L 13 + L 28		(13,127)	2,004	(11,123)
34	Total Income Tax Expense	L 32 + L 33		$ (51,956)	$ 5,796	$ (46,160)

[1] Due to the 2018 Tax Cuts and Jobs Act, excess deferred income tax is now being flowed back to customers which results in a deferred tax rate other than 21%.

($ in Thousands)

Tax Depreciation

Line #	Description	[1] Amount	[2] Amount	[3] Total
	Accelerated Tax Depreciation			
1	Gas Plant		$ 137,581	
2	Cost of Removal		6,943	
3	Repairs Tax Deduction		65,494	
4	Other Tax Basis Adjustments		(20,006)	
5	Total Federal Accelerated Tax Depreciation			$ 190,012
6	Adjustment for PA Tax Depreciation - Bonus Decoupling		28,083	
7	Total State Accelerated Tax Depreciation			$218,095
	Straight Line Tax Depreciation			
8	Gas Plant		$ 106,728	
9	Total Tax Depreciation			$ 106,728
	Book Depreciation			
10	Pro Forma Book Depreciation		$ 106,728	
11	Net Salvage Amortization		8,007	
12	Depreciation Charged to Clearing Accounts	(5,822)		
13	Estimated Percent of Clearing Charged to CWIP	39%		
14	Depreciation Charged to CWIP		(2,247)	
15	Book Depreciation for Tax Calculation			$ 112,488

($ in Thousands)

Gross Revenue Conversion Factor

Line #	Description	[1] Reference Or Factor	[2] Tax Rate	[3] Factor
GROSS REVENUE CONVERSION FACTOR				
1	GROSS REVENUE FACTOR			1.000000
2	UNCOLLECTIBLE EXPENSES			(0.016470)
3	NET REVENUES	Sum L 1 to L 2		0.983530
4	STATE INCOME TAXES	[3] L 3 * Rate [2]	9.9900%	(0.098255)
5	FACTOR AFTER STATE TAXES	L 3 + L 4		0.885275
6	FEDERAL INCOME TAXES	[3] L 5 * Rate [2]	21.00%	(0.185908)
7	NET OPERATING INCOME FACTOR	L 5 + L 6		0.699367
8	GROSS REVENUE CONVERSION FACTOR	1 / L 7		1.429864
9	Combined Income Tax Factor On Gross Revenues	-L 4 - L 6		28.416%
INCOME TAX FACTOR				
10	GROSS REVENUE FACTOR			1.000000
11	STATE INCOME TAXES	[3] L 10 * Rate [2]	9.9900%	(0.099900)
12	FACTOR AFTER STATE TAXES	L 10 + L 11		0.900100
13	FEDERAL INCOME TAXES	[3] L 12 * Rate [2]	21.00%	(0.189021)
14	NET OPERATING INCOME FACTOR	L 12 + L 13		0.711079
15	GROSS REVENUE CONVERSION FACTOR	1 / L 14		1.406314
16	Combined Income Tax Factor On Taxable Income	-L 11 - L 13		28.892%

UGI GAS

EXHIBIT B – RATE OF RETURN

UGI Utilities, Inc. – Gas Division

Exhibit to Accompany the

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Concerning

Fair Rate of Return

UGI Utilities, Inc. – Gas Division

Index of Schedules

UGI Utilities, Inc.
Proposed Rate of Return
Estimated at September 30, 2023

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	44.88%	3.98%	1.79%
Common Equity	55.12%	11.20%	6.17%
Total	100.00%		7.96%

Indicated levels of fixed charge coverage assuming that
the Company could actually achieve its proposed rate of return:

Pre-tax coverage of interest expense based upon a
28.8921% composite federal and state income tax rate
(10.47% ÷ 1.79%) 5.85 x

Post-tax coverage of interest expense
(7.96% ÷ 1.79%) 4.45 x

UGI Utilities, Inc.
Cost of Equity
as of September 30, 2021

Discounted Cash Flow (DCF)					D_1/P_0 [1]	**+**	*g* [2]	**+**	*lev.* [3]	**=**	***k***
Gas Group					3.51%	+	6.75%	+	0.95%	=	11.21%
Risk Premium (RP)							*I* [4]	**+**	*RP* [5]	=	***k***
Gas Group							3.75%	+	6.75%	=	10.50%
Capital Asset Pricing Model (CAPM)	*Rf* [6]	**+**	*ß* [7]		*x (*		*Rm-Rf* [8]	*) +*	*size* [9]	**=**	***k***
Gas Group	2.75%	+	1.00		x (		9.78%	) +	1.02%	=	13.55%
Comparable Earnings (CE) [10]							***Historical***		***Forecast***		***Average***
Comparable Earnings Group							12.5%		12.9%		12.70%

References:
(1) Schedule 07
(2) Schedule 09
(3) Schedule 10
(4) A-rated public utility bond yield comprised of a 2.75% risk-free rate of return (Schedule 14 page 2) and a yield spread of 1.00% (Schedule 12 page 3)
(5) Schedule 12 page 1
(6) Schedule 13 page 2
(7) Schedule 10
(8) Schedule 13 page 2
(9) Schedule 13 page 3
(10) Schedule 14 page 2

UGI Utilities, Inc.
Capitalization and Financial Statistics
2016-2020, Inclusive

	2020	2019	2018	2017	2016	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 2,435.0	$ 2,207.5	$ 1,951.6	$ 1,765.8	$ 1,627.8	
Short-Term Debt	$ 141.0	$ 166.0	$ 189.5	$ 170.0	$ 112.5	
Total Capital	$ 2,576.0	$ 2,373.5	$ 2,141.1	$ 1,935.8	$ 1,740.3	
Capital Structure Ratios						
Based on Permanent Captial:						Average
Long-Term Debt	46.0%	44.4%	42.9%	42.5%	41.2%	43.4%
Common Equity (1)	54.0%	55.6%	57.1%	57.5%	58.8%	56.6%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	49.0%	48.2%	48.0%	47.6%	45.0%	47.6%
Common Equity (1)	51.0%	51.8%	52.0%	52.4%	55.0%	52.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (1)	10.7%	11.4%	14.0%	11.8%	10.5%	11.7%
Operating Ratio (2)	77.8%	78.5%	78.5%	75.2%	73.6%	76.7%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	4.24 x	4.55 x	5.54 x	5.68 x	5.34 x	5.07 x
Post-tax: All Interest Charges	3.52 x	3.68 x	4.47 x	3.89 x	3.59 x	3.83 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	4.24 x	4.55 x	5.54 x	5.68 x	5.34 x	5.07 x
Post-tax: All Interest Charges	3.52 x	3.68 x	4.47 x	3.89 x	3.59 x	3.83 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Effective Income Tax Rate	22.3%	24.4%	23.5%	38.3%	40.4%	29.8%
Internal Cash Generation/Construction (4)	68.7%	67.8%	86.8%	75.6%	63.0%	72.4%
Gross Cash Flow/ Avg. Total Debt (5)	23.5%	24.9%	33.9%	33.9%	27.7%	28.8%
Gross Cash Flow Interest Coverage (6)	6.15 x	6.58 x	8.70 x	7.91 x	6.41 x	7.15 x
Common Dividend Coverage (7)	5.66 x	13.55 x	6.61 x	5.00 x	4.36 x	7.04 x

See Page 2 for Notes.

UGI Utilities, Inc.
Capitalization and Financial Statistics
2016-2020, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Certified financial statements

Gas Group
Capitalization and Financial Statistics [1]
2016-2020, Inclusive

	2020	2019	2018	2017	2016	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 5,894.0	$ 5,169.4	$ 4,698.4	$ 4,133.8	$ 3,746.8	
Short-Term Debt	$ 319.8	$ 553.3	$ 499.2	$ 402.2	$ 393.6	
Total Capital	$ 6,213.8	$ 5,722.7	$ 5,197.6	$ 4,536.0	$ 4,140.4	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	23 x	26 x	20 x	22 x	22 x	23 x
Market/Book Ratio	185.6%	222.5%	217.6%	224.2%	201.9%	210.4%
Dividend Yield	3.2%	2.7%	2.8%	2.6%	2.8%	2.8%
Dividend Payout Ratio	74.5%	71.9%	52.4%	53.3%	60.7%	62.6%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	50.2%	48.3%	47.9%	47.1%	45.0%	47.7%
Preferred Stock	1.6%	1.5%	1.0%	0.0%	0.1%	0.8%
Common Equity [2]	48.2%	50.3%	51.1%	52.9%	54.9%	51.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	53.9%	53.4%	53.4%	53.0%	50.5%	52.8%
Preferred Stock	1.5%	1.3%	0.9%	0.0%	0.1%	0.7%
Common Equity [2]	44.6%	45.3%	45.7%	47.0%	49.5%	46.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	8.8%	8.7%	10.0%	8.0%	9.2%	8.9%
Operating Ratio [3]	82.6%	83.6%	84.6%	84.1%	83.0%	83.6%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.99 x	3.80 x	3.65 x	4.22 x	4.88 x	4.11 x
Post-tax: All Interest Charges	3.47 x	3.38 x	3.47 x	3.31 x	3.58 x	3.44 x
Overall Coverage: All Int. & Pfd. Div.	3.43 x	3.34 x	3.47 x	3.31 x	3.58 x	3.43 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.89 x	3.74 x	3.60 x	4.19 x	4.82 x	4.05 x
Post-tax: All Interest Charges	3.36 x	3.31 x	3.42 x	3.27 x	3.52 x	3.38 x
Overall Coverage: All Int. & Pfd. Div.	3.32 x	3.27 x	3.42 x	3.27 x	3.52 x	3.36 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.3%	3.0%	3.2%	-5.2%	2.3%	1.3%
Effective Income Tax Rate	19.7%	14.9%	15.6%	39.7%	33.6%	24.7%
Internal Cash Generation/Construction [5]	53.5%	48.7%	46.7%	59.5%	71.6%	56.0%
Gross Cash Flow/ Avg. Total Debt [6]	18.0%	18.3%	18.4%	21.4%	23.7%	20.0%
Gross Cash Flow Interest Coverage [7]	6.95 x	6.25 x	6.05 x	6.69 x	7.35 x	6.66 x
Common Dividend Coverage [8]	3.84 x	3.86 x	3.63 x	4.21 x	4.60 x	4.03 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2016-2020, Inclusive

Notes:
(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income (“OCI”) from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that are contained in The Value Line Investment Survey within the industry group “Natural Gas Utility,” they are not currently the target of a publicly-announced merger or acquisition, and after eliminating UGI Corp. due to its highly diversified businesses.

ATO	Atmos Energy Corp.	A1	A-	NYSE	0.80
CPK	Chesapeake Utilities Corp.	NAIC "1"		NYSE	0.80
NJR	New Jersey Resources Corp.	A1	-	NYSE	1.00
NI	NiSource Inc.	Baa2	BBB+	NYSE	0.85
NWN	Northwest Natural Holding Compa	Baa1	A+	NYSE	0.85
OGS	ONE Gas, Inc.	A3	BBB+	NYSE	0.80
SJI	South Jersey Industries, Inc.	A3	BBB	NYSE	1.05
SWX	Southwest Gas Holdings, Inc.	Baa1	A-	NYSE	0.95
SR	Spire, Inc.	A1	A-	NYSE	0.85
	Average	A3	A-		0.88

Note: Ratings are those of utility subsidiaries

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT
Moody’s Investors Service
Standard & Poor’s Corporation

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2016-2020, Inclusive

	2020	2019	2018	2017	2016	Average
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 38,743.7	$ 36,461.6	$ 32,871.6	$ 30,827.6	$ 29,173.1	
Short-Term Debt	$ 1,154.5	$ 1,221.9	$ 1,420.3	$ 1,076.1	$ 1,032.2	
Total Capital	$ 39,898.2	$ 37,683.5	$ 34,291.9	$ 31,903.7	$ 30,205.3	
Market-Based Financial Ratios						
Price-Earnings Multiple	22 x	20 x	21 x	20 x	21 x	21 x
Market/Book Ratio	218.5%	221.3%	204.7%	214.4%	196.0%	211.0%
Dividend Yield	3.6%	3.2%	3.5%	3.3%	3.5%	3.4%
Dividend Payout Ratio	77.8%	62.7%	68.7%	65.2%	74.6%	69.8%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	58.1%	56.7%	55.0%	56.8%	56.6%	56.6%
Preferred Stock	2.6%	2.4%	2.5%	1.4%	1.9%	2.1%
Common Equity [2]	39.4%	41.0%	42.5%	41.8%	41.6%	41.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	59.4%	58.1%	57.0%	58.4%	58.2%	58.2%
Preferred Stock	2.5%	2.3%	2.4%	1.4%	1.8%	2.1%
Common Equity [2]	38.1%	39.6%	40.7%	40.3%	40.1%	39.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.2%	10.3%	10.3%	10.8%	9.7%	10.3%
Operating Ratio [3]	79.8%	79.3%	79.8%	77.0%	78.2%	78.8%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	2.80 x	3.05 x	2.94 x	3.42 x	3.38 x	3.12 x
Post-tax: All Interest Charges	2.60 x	3.10 x	2.59 x	2.86 x	2.55 x	2.74 x
Overall Coverage: All Int. & Pfd. Div.	2.56 x	3.04 x	2.55 x	2.84 x	2.52 x	2.70 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.70 x	2.95 x	2.84 x	3.31 x	3.28 x	3.02 x
Post-tax: All Interest Charges	2.50 x	3.00 x	2.48 x	2.75 x	2.44 x	2.63 x
Overall Coverage: All Int. & Pfd. Div.	2.46 x	2.94 x	2.44 x	2.73 x	2.41 x	2.60 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	6.8%	6.0%	7.3%	7.3%	6.5%	6.8%
Effective Income Tax Rate	10.2%	12.2%	19.0%	28.2%	29.0%	19.7%
Internal Cash Generation/Construction [5]	58.6%	65.9%	66.2%	78.7%	78.0%	69.5%
Gross Cash Flow/ Avg. Total Debt [6]	15.9%	17.5%	17.4%	19.9%	20.5%	18.2%
Gross Cash Flow Interest Coverage [7]	4.90 x	4.97 x	4.98 x	5.57 x	5.54 x	5.19 x
Common Dividend Coverage [8]	3.52 x	5.56 x	4.80 x	4.33 x	4.31 x	4.50 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2016-2020, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities
Company Identities

	Ticker	Credit Rating [1] Moody's	S&P	Common Stock Traded	Value Line Beta
Alliant Energy Corporation	LNT	Baa1	A-	NYSE	0.85
Ameren Corporation	AEE	Baa1	BBB+	NYSE	0.85
American Electric Power	AEP	Baa1	A-	NYSE	0.75
American Water Works	AWK	Baa1	A	NYSE	0.85
CenterPoint Energy	CNP	Baa1	BBB+	NYSE	1.15
CMS Energy	CMS	A3	A-	NYSE	0.80
Consolidated Edison	ED	Baa1	A-	NYSE	0.75
Dominion Energy	D	A2	BBB+	NYSE	0.80
DTE Energy Co.	DTE	A2	A-	NYSE	0.95
Duke Energy	DUK	A1	BBB+	NYSE	0.85
Edison Int'l	EIX	Baa2	BBB	NYSE	0.95
Entergy Corp.	ETR	Baa1	A-	NYSE	0.95
Evergy, Inc.	EVRG	Baa1	A-	NYSE	1.00
Eversource	ES	A3	A	NYSE	0.90
Exelon Corp.	EXC	A2	BBB+	NYSE	0.95
FirstEnergy Corp.	FE	A3	BB+	NYSE	0.85
NextEra Energy Inc.	NEE	A1	A	NYSE	0.90
NiSource Inc.	NI	Baa2	BBB+	NYSE	0.85
NRG Energy Inc.	NRG	Ba1	BB+	NYSE	1.25
Pinnacle West Capital	PNW	A2	A-	NYSE	0.90
PPL Corp.	PPL	A3	A-	NYSE	1.15
Public Serv. Enterprise Inc.	PEG	A2	A-	NYSE	0.90
Sempra Energy	SRE	Baa1	BBB+	NYSE	1.00
Southern Co.	SO	Baa1	A-	NYSE	0.90
WEC Energy Corp.	WEC	A2	A-	NYSE	0.80
Xcel Energy Inc	XEL	A2	A-	NYSE	0.80
Average for S&P Utilities		A3	BBB+		0.91

Note: [1] Ratings are those of utility subsidiaries

Source of Information: SNL Financial LLC
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

UGI Utilities, Inc.
Capitalization and Related Capital Structure Ratios
Actual at September 30, 2021 and Estimated at September 30, 2022 and September 30, 2023

	Actual at September 30, 2021			Estimated at September 30, 2022			Estimated at September 30, 2023		
		Capital Structure Ratios			Capital Structure Ratios			Capital Structure Ratios	
	Amount Outstanding ($000)	Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding ($000)	Incl. S-T Debt	Excl. S-T Debt	Amount Outstanding ($000)	Incl. S-T Debt	Excl. S-T Debt
Long-Term Debt [1]	$ 1,291,563	45.97%	47.55%	$ 1,405,000 [2]	45.55%	46.21%	$ 1,483,750 [2]	44.88%	44.88%
Common Equity									
Common Stock	60,259			60,259			60,259		
Other Paid-In Capital	473,580			508,580 [4]			508,580		
Retained Earnings [3]	891,062			1,066,494 [5]			1,253,439 [5]		
Total Common Equity	1,424,901	50.71%	52.45%	1,635,333	53.01%	53.79%	1,822,278	55.12%	55.12%
Total Permanent Capital	2,716,464	96.68%	100.00%	3,040,333	98.56%	100.00%	3,306,028	100.00%	100.00%
Avg. Net Short-Term Debt [6]	93,162	3.32%		44,426	1.44%		-	0.00%	
Total Capital Employed	$ 2,809,626	100.00%		$ 3,084,759	100.00%		$ 3,306,028	100.00%	

Notes:

[1] Includes current portion of long-term debt.

[2] Reflects change in long-term debt consisting of:

	2021	2022	2023
Principal payments		$ (101,563)	$ (6,250)
New issues		$ 215,000	$ 85,000

[3] Excludes Accumulated Other Comprehensive Income of:

	2021	2022	2023
	$ (22,437)	$ (22,437)	$ (22,437)

[4] Reflects capital contribution of:

	2021	2022	2023
		$ 35,000	

[5] Reflects change in retained earnings consisting of:

	2021	2022	2023
Net income		$ 175,432	$ 186,945
Common Dividends		$ -	$ -

[6] Average Short-Term Debt

	2021	2022	2023
Balance	$ 187,667	$ 173,201	$ 134,484
Less: CWIP	(94,505)	(128,775)	(136,995)
Net	$ 93,162	$ 44,426	$ (2,511)

Source of Information: Company provided data

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Estimated at September 30, 2021

Series	Date of Maturity	Principal Amount Outstanding ($000)	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	$ 20,000	1.55%	6.56%	0.10%
6.133%	10/15/34	20,000	1.55%	6.19%	0.10%
Senior Notes					
6.206%	09/30/36	100,000	7.74%	6.32%	0.49%
4.980%	03/26/44	175,000	13.55%	5.00%	0.68%
2.950%	06/30/26	100,000	7.74%	3.92%	0.30%
4.120%	09/30/46	200,000	15.49%	5.01%	0.78%
4.120%	10/31/46	100,000	7.74%	4.28%	0.33%
2.998%	10/31/22	101,563	7.86%	3.12%	0.25%
4.550%	02/01/49	150,000	11.61%	4.58%	0.53%
3.120%	04/16/50	150,000	11.61%	3.15%	0.37%
1.590%	06/15/26	100,000	7.74%	1.73%	0.13%
1.640%	09/15/26	75,000	5.81%	1.75%	0.10%
Total Long-Term Debt		$ 1,291,563	100.00%		4.16%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Estimated at September 30, 2022

Series	Date of Maturity	Principal Amount Outstanding ($000)	Percent to Total	Effective Cost Rate (1)	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	$ 20,000	1.42%	6.56%	0.09%
6.133%	10/15/34	20,000	1.42%	6.19%	0.09%
Senior Notes					
6.206%	09/30/36	100,000	7.12%	6.32%	0.45%
4.980%	03/26/44	175,000	12.46%	5.00%	0.62%
2.950%	06/30/26	100,000	7.12%	3.92%	0.28%
4.120%	09/30/46	200,000	14.24%	5.01%	0.71%
4.120%	10/31/46	100,000	7.12%	4.28%	0.30%
4.550%	02/01/49	150,000	10.68%	4.58%	0.49%
3.120%	04/16/50	150,000	10.68%	3.15%	0.34%
1.590%	06/15/26	100,000	7.12%	1.73%	0.12%
1.640%	09/15/26	75,000	5.34%	1.75%	0.09%
3.687%	05/31/52	90,000	6.41%	3.71%	0.24%
1.410%	07/31/27	125,000	8.90%	1.53%	0.14%
Total Long-Term Debt		$ 1,405,000	100.00%		3.96%

Notes: (1) As calculated on page 4 of this schedule.

Source of Information: Company provided data

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Estimated at September 30, 2023

Series	Date of Maturity	Principal Amount Outstanding ($000)	Percent to Total	Effective Cost Rate (1)	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	$ 20,000	1.35%	6.56%	0.09%
6.133%	10/15/34	20,000	1.35%	6.19%	0.08%
Senior Notes					
6.206%	09/30/36	100,000	6.74%	6.32%	0.43%
4.980%	03/26/44	175,000	11.79%	5.00%	0.59%
2.950%	06/30/26	100,000	6.74%	3.92%	0.26%
4.120%	09/30/46	200,000	13.48%	5.01%	0.68%
4.120%	10/31/46	100,000	6.74%	4.28%	0.29%
4.550%	02/01/49	150,000	10.11%	4.58%	0.46%
3.120%	04/16/50	150,000	10.11%	3.15%	0.32%
1.590%	06/15/26	100,000	6.74%	1.73%	0.12%
1.640%	09/15/26	75,000	5.06%	1.75%	0.09%
3.687%	05/31/52	90,000	6.07%	3.71%	0.23%
1.410%	07/31/27	118,750	8.00%	1.53%	0.12%
3.791%	10/31/52	85,000	5.73%	3.82%	0.22%
Total Long-Term Debt		$ 1,483,750	100.00%		3.98%

Notes: (1) As calculated on page 4 of this schedule.

Source of Information: Company provided data

UGI Utilities, Inc.

Calculation of the Effective Cost of Long-Term Debt by Series

Series	Date of Issue	Date of Maturity	Average Term in Years [1]	Principal Amount Issued	Premium/ Discount & Expense ($000)	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate [2]
Medium Term Notes								
6.500%	08/14/03	08/15/33	30	$ 20,000	$ 150	$ 19,850	99.25%	6.56%
6.133%	10/14/04	10/15/34	30	20,000	150	19,850	99.25%	6.19%
Senior Notes								
6.206%	11/14/06	09/30/36	30	100,000	1,485	98,515	98.52%	6.32%
4.980%	03/26/14	03/26/44	30	175,000	642	174,358	99.63%	5.00%
2.950%	06/30/16	06/30/26	10	100,000	7,949	92,051	92.05%	3.92%
4.120%	09/30/16	09/30/46	30	200,000	27,366	172,634	86.32%	5.01%
4.120%	10/31/16	10/31/46	30	100,000	2,710	97,290	97.29%	4.28%
2.998%	10/31/17	10/31/22	4.6875	125,000	674	124,326	99.46%	3.12%
4.550%	02/28/19	02/01/49	30	150,000	713	149,288	99.53%	4.58%
3.120%	03/19/20	04/16/50	30	150,000	835	149,165	99.44%	3.15%
1.590%	06/15/21	06/15/26	5	100,000	680	99,320	99.32%	1.73%
1.640%	09/15/21	09/15/26	5	75,000	390	74,611	99.48%	1.75%
3.687%	05/31/22	05/31/52	30	90,000	450	89,550	99.50%	3.71%
1.410%	07/31/22	07/31/27	5	125,000	750	124,250	99.40%	1.53%
3.791%	10/31/22	10/31/52	30	85,000	425	84,575	99.50%	3.82%

Notes: [1] Determined by taking into account the effect of the annual sinking fund requirements which are met by the retirement of principal which reduce the term of each issue.

[2] The effective cost for each issue is the yield to maturity using as inputs the average term of issue, coupon rate, and net proceeds ratio.

Source of Information: Company provided data

Monthly Dividend Yields for
Natural Gas Group
for the Twelve Months Ending September 2021

Company	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	12-Month Average	6-Month Average	3-Month Average
Atmos Energy Corp (ATO)	2.74%	2.61%	2.63%	2.82%	2.96%	2.54%	2.42%	2.52%	2.61%	2.55%	2.57%	2.84%			
Chesapeake Utilities Corp (CPK)	1.81%	1.70%	1.63%	1.74%	1.67%	1.52%	1.62%	1.68%	1.60%	1.54%	1.47%	1.60%			
New Jersey Resources Corporation (NJR)	4.58%	4.06%	3.75%	3.82%	3.41%	3.34%	3.18%	3.13%	3.37%	3.78%	3.92%	4.17%			
NiSource Inc (NI)	3.66%	3.48%	3.69%	4.01%	4.08%	3.67%	3.38%	3.46%	3.61%	3.55%	3.58%	3.65%			
Northwest Natural Holding Company (NWN)	4.32%	4.02%	4.21%	4.11%	4.01%	3.58%	3.56%	3.64%	3.68%	3.67%	3.74%	4.21%			
ONE Gas Inc (OGS)	3.15%	2.73%	2.82%	3.19%	3.47%	3.03%	2.90%	3.13%	3.14%	3.17%	3.24%	3.68%			
South Jersey Industries Inc (SJI)	6.34%	5.32%	5.63%	5.28%	4.87%	5.37%	4.92%	4.58%	4.68%	4.84%	4.93%	5.71%			
Southwest Gas Holdings Inc (SWX)	3.50%	3.55%	3.77%	3.83%	3.66%	3.33%	3.44%	3.61%	3.61%	3.43%	3.39%	3.58%			
Spire Inc. (SR)	4.67%	4.10%	4.07%	4.27%	3.95%	3.53%	3.47%	3.66%	3.60%	3.68%	3.93%	4.26%			
Average	3.86%	3.51%	3.58%	3.67%	3.56%	3.32%	3.21%	3.27%	3.32%	3.36%	3.42%	3.74%	3.49%	3.39%	3.51%

Note: Monthly dividend yields are calculated by dividing the annualized quarterly dividend by the month-end closing stock price adjusted by the fraction of the ex-dividend.

Source of Information: https://finance.yahoo.com/quote
https://www.nasdaq.com/market-activity/stocks

Forward-looking Dividend Yield

1/2 Growth	D_0/P_0	(.5g)	D_1/P_0
	3.39%	1.033750	3.50%
Discrete	D_0/P_0	Adj.	D_1/P_0
	3.39%	1.041843	3.53%
Quarterly	D_0/P_0	Adj.	D_1/P_0
	0.8467%	1.016464	3.49%
Average			3.51%
Growth rate			6.75%
K			10.26%

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

$$K = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

Historical Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

Gas Group	Earnings per Share Value Line 5 Year	Earnings per Share Value Line 10 Year	Dividends per Share Value Line 5 Year	Dividends per Share Value Line 10 Year	Book Value per Share Value Line 5 Year	Book Value per Share Value Line 10 Year	Cash Flow per Share Value Line 5 Year	Cash Flow per Share Value Line 10 Year
Atmos Energy Corp.	9.00%	8.00%	7.50%	5.00%	10.00%	7.50%	7.00%	5.50%
Chesapeake Utilities Corp.	9.00%	9.50%	7.50%	6.50%	11.00%	9.50%	7.50%	9.50%
New Jersey Resources Corp.	5.50%	6.00%	6.50%	7.00%	8.50%	7.50%	7.00%	7.00%
Nisource Inc.	0.50%	2.00%	-3.00%	-1.50%	-5.00%	-3.00%	-	-0.50%
Northwest Natural Gas	1.50%	-1.50%	0.50%	1.50%	-	1.00%	1.50%	0.50%
One Gas, Inc.	10.00%	-	14.50%	-	3.00%	1.00%	8.00%	-
South Jersey Industries, Inc.	-1.50%	1.50%	4.00%	6.50%	2.50%	5.50%	3.00%	4.50%
Southwest Gas Corp.	5.50%	7.50%	8.00%	8.50%	7.00%	6.00%	1.50%	4.00%
Spire, Inc.	4.50%	1.50%	6.00%	4.50%	5.50%	7.00%	8.50%	4.50%
Average	4.89%	4.31%	5.72%	4.75%	5.31%	4.67%	5.50%	4.38%

Source of Information: Value Line Investment Survey, August 27, 2021

Analysts' Five-Year Projected Growth Rates
Earnings Per Share, Dividends Per Share,
Book Value Per Share, and Cash Flow Per Share

			Value Line				
Gas Group	I/B/E/S First Call	Zacks	Earnings Per Share	Dividends Per Share	Book Value Per Share	Cash Flow Per Share	Percent Retained to Common Equity
Atmos Energy Corp (ATO)	7.80%	7.40%	7.00%	7.50%	10.50%	5.00%	3.50%
Chesapeake Utilities Corp (CPK)	4.74%	NA	8.50%	8.00%	6.50%	9.50%	7.50%
New Jersey Resources Corporation	6.00%	7.10%	2.00%	5.50%	6.00%	3.00%	3.50%
NiSource Inc (NI)	3.52%	6.20%	9.50%	4.50%	4.50%	6.00%	5.50%
Northwest Natural Holding Compan	5.50%	4.90%	5.50%	0.50%	8.50%	4.00%	2.50%
ONE Gas Inc (OGS)	5.00%	5.00%	6.50%	7.00%	10.50%	6.00%	3.00%
South Jersey Industries Inc (SJI)	4.80%	5.40%	11.50%	4.50%	5.00%	6.00%	5.50%
Southwest Gas Holdings Inc (SWX)	4.00%	5.50%	8.00%	4.50%	7.00%	7.00%	5.00%
Spire Inc. (SR)	7.31%	5.50%	10.00%	4.50%	7.50%	8.00%	3.00%
Average	5.41%	5.88%	7.61%	5.17%	7.33%	6.06%	4.33%

Source of Information : Yahoo Finance, September 29, 2021
Zacks, September 29, 2021
Value Line Investment Survey, August 27, 2021

Gas Group
Financial Risk Adjustment

		ATMOS Energy (NYSE:ATO)	Chesapeake Utilities (NYSE:CPK)	New Jersey Resources (NYSE:NJR)	NiSource, Inc (NYSE:NI)	Northwest Natural Gas (NYSE:NWN)	ONE Gas Inc (NYSE:OGS)	South Jersey Industries (NYSE:SJI)	Southwest Gas (SWX)	Spire Inc. (NYSESR)	Average
Fiscal Year		09/30/20	12/31/20	09/30/20	12/31/20	12/31/20	12/31/20	12/31/20	12/31/20	09/30/20	
Capitalization at Fair Values											
	Debt(D)	5,597,183	548,500	2,417,748	11,034,200	1,136,311	2,000,000	3,152,224	3,148,818	2,908,600	3,549,287
	Preferred(P)	0	0	0	0	0	0	0	0	242,000	26,889
	Equity(E)	12,033,105	1,889,546	2,588,540	8,986,976	1,406,788	4,081,610	2,162,231	3,474,470	2,745,747	4,374,335
	Total	17,630,288	2,438,046	5,006,288	20,021,176	2,543,099	6,081,610	5,314,455	6,623,288	5,896,347	7,950,511
Capital Structure Ratios											
	Debt(D)	31.75%	22.50%	48.29%	55.11%	44.68%	32.89%	59.31%	47.54%	49.33%	43.49%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.10%	0.46%
	Equity(E)	68.25%	77.50%	51.71%	44.89%	55.32%	67.11%	40.69%	52.46%	46.57%	56.06%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.01%
Common Stock											
	Issued	125,882.477	17,461.841	95,949.183	391,760.051	30,589.000	53,166.733	100,591.940	57,192.925	51,611.789	
	Treasury	0.000	0.000	148.310	0.000	0.000	0.000	256.372	0.000	0.000	
	Outstanding	125,882.477	17,461.841	95,800.873	391,760.051	30,589.000	53,166.733	100,335.568	57,192.925	51,611.789	
	Market Price	$ 95.59	$ 108.21	$ 27.02	$ 22.94	$ 45.99	$ 76.77	$ 21.55	$ 60.75	$ 53.20	
Capitalization at Carrying Amounts											
	Debt(D)	4,560,000	523,000	2,102,845	9,243,100	955,425	1,600,000	2,919,201	2,772,633	2,484,100	3,017,812
	Preferred(P)	0	0	0	0	0	0	0	0	242,000	26,889
	Equity(E)	6,791,203	697,085	1,844,692	4,872,200	888,733	2,233,311	1,660,881	2,674,953	2,280,300	2,660,373
	Total	11,351,203	1,220,085	3,947,537	14,115,300	1,844,158	3,833,311	4,580,082	5,447,586	5,006,400	5,705,074
Capital Structure Ratios		53.95	39.92	19.26	12.44	29.05	42.01	16.55	46.77	44.18	
	Debt(D)	40.17%	42.87%	53.27%	65.48%	51.81%	41.74%	63.74%	50.90%	49.62%	51.07%
	Preferred(P)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.83%	0.54%
	Equity(E)	59.83%	57.13%	46.73%	34.52%	48.19%	58.26%	36.26%	49.10%	45.55%	48.40%
	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Betas	Value Line	0.80	0.80	1.00	0.85	0.85	0.80	1.05	0.95	0.85	0.88

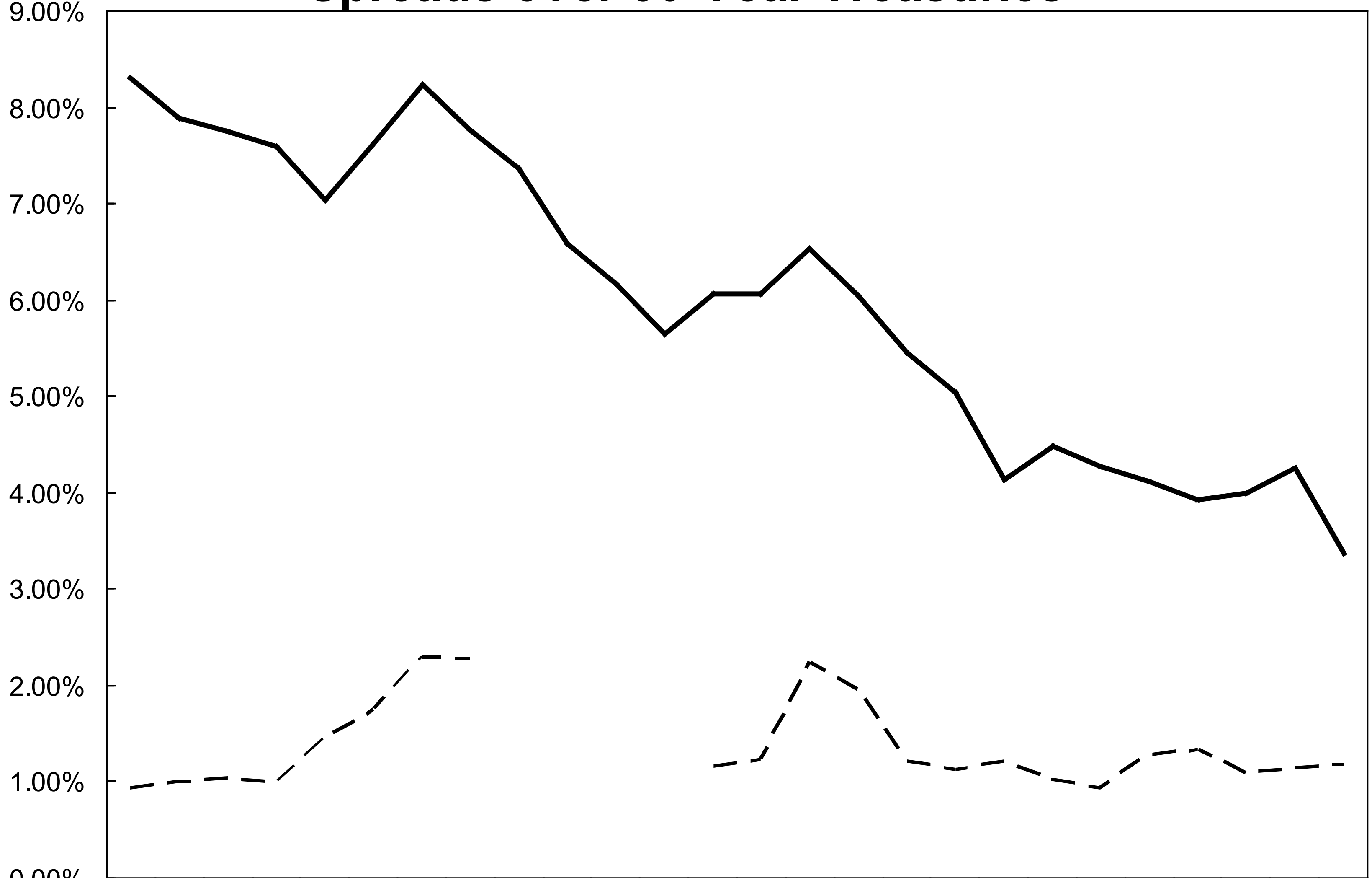
Hamada	Bl	=	Bu	[1+	(1 - t)	D/E	+	P/E	]
	0.88	=	Bu	[1+	(1-0.21)	0.7758	+	0.0082	]
	0.88	=	Bu	[1+	0.79	0.7758	+	0.0082	]
	0.88	=	Bu	1.6211					
	0.54	=	Bu						
Hamada	Bl	=	0.54	[1+	(1 - t)	D/E	+	P/E	]
	Bl	=	0.54	[1+	0.79	1.0552	+	0.0111	]
	Bl	=	0.54	1.8447					
	Bl	=	1.00						

M&M	ku	=	ke	-	(((	ku	-	i	)	1-t	)	D	/	E	-	(ku	-	d	)	P	/	E
	7.52%	=	10.26%	-	(((	7.52%	-	3.11%	)	0.79	)	43.49%	/	56.06%	-	7.52%	-	5.68%	)	0.46%	/	56.06%
	7.52%	=	10.26%	-	(((	4.41%			)	0.79	)	0.7758			-	1.84%			)	0.0082		
	7.52%	=	10.26%	-	((	3.48%					)	0.7758			-	1.84%			)	0.0082		
	7.52%	=	10.26%	-		2.70%									-	0.02%						
M&M	ke	=	ku	+	(((	ku	-	i	)	1-t	)	D	/	E	+	(ku	-	d	)	P	/	E
	11.21%	=	7.52%	+	(((	7.52%	-	3.11%	)	0.79	)	51.07%	/	48.40%	+	7.52%	-	5.68%	)	0.54%	/	48.40%
	11.21%	=	7.52%	+	(((	4.41%			)	0.79	)	1.0552			+	1.84%			)	0.0111		
	11.21%	=	7.52%	+	((	3.48%					)	1.0552			+	1.84%			)	0.0111		
	11.21%	=	7.52%	+		3.67%									+	0.02%						

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2016-2020
and the Twelve Months Ended September 2021

Years	Aa Rated	A Rated	Baa Rated	Average
2016	3.73%	3.93%	4.68%	4.11%
2017	3.82%	4.00%	4.38%	4.07%
2018	4.09%	4.25%	4.67%	4.34%
2019	3.61%	3.77%	4.19%	3.86%
2020	2.79%	3.02%	3.39%	3.07%
Five-Year Average	3.61%	3.79%	4.26%	3.89%
Months				
Oct-20	2.72%	2.95%	3.27%	2.98%
Nov-20	2.63%	2.85%	3.17%	2.89%
Dec-20	2.57%	2.77%	3.05%	2.80%
Jan-21	2.73%	2.91%	3.18%	2.94%
Feb-21	2.93%	3.09%	3.37%	3.13%
Mar-21	3.27%	3.44%	3.72%	3.48%
Apr-21	3.13%	3.30%	3.57%	3.33%
May-21	3.17%	3.33%	3.58%	3.36%
Jun-21	3.01%	3.16%	3.41%	3.19%
Jul-21	2.80%	2.95%	3.20%	2.99%
Aug-21	2.82%	2.95%	3.19%	2.99%
Sep-21	2.84%	2.96%	3.19%	3.00%
Twelve-Month Average	2.89%	3.06%	3.33%	3.09%
Six-Month Average	2.96%	3.11%	3.36%	3.14%
Three-Month Average	2.82%	2.95%	3.19%	2.99%

Yields on
A-rated Public Utility Bonds and
Spreads over 30-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
A-rated Public Utility	8.31	7.89	7.75	7.60	7.04	7.62	8.24	7.76	7.37	6.58	6.16	5.65	6.07	6.07	6.53	6.04	5.46	5.04	4.13	4.48	4.28	4.12	3.93	4.00	4.25	3.37
Spread vs. 30-year	0.94	1.01	1.04	0.99	1.46	1.75	2.30	2.27					1.16	1.23	2.25	1.96	1.21	1.13	1.21	1.03	0.94	1.28	1.34	1.10	1.14	1.19

A rated Public Utility Bonds over 30-Year Treasuries

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-99	6.97%	5.16%	1.81%
Feb-99	7.09%	5.37%	1.72%
Mar-99	7.26%	5.58%	1.68%
Apr-99	7.22%	5.55%	1.67%
May-99	7.47%	5.81%	1.66%
Jun-99	7.74%	6.04%	1.70%
Jul-99	7.71%	5.98%	1.73%
Aug-99	7.91%	6.07%	1.84%
Sep-99	7.93%	6.07%	1.86%
Oct-99	8.06%	6.26%	1.80%
Nov-99	7.94%	6.15%	1.79%
Dec-99	8.14%	6.35%	1.79%
Jan-00	8.35%	6.63%	1.72%
Feb-00	8.25%	6.23%	2.02%
Mar-00	8.28%	6.05%	2.23%
Apr-00	8.29%	5.85%	2.44%
May-00	8.70%	6.15%	2.55%
Jun-00	8.36%	5.93%	2.43%
Jul-00	8.25%	5.85%	2.40%
Aug-00	8.13%	5.72%	2.41%
Sep-00	8.23%	5.83%	2.40%
Oct-00	8.14%	5.80%	2.34%
Nov-00	8.11%	5.78%	2.33%
Dec-00	7.84%	5.49%	2.35%
Jan-01	7.80%	5.54%	2.26%
Feb-01	7.74%	5.45%	2.29%
Mar-01	7.68%	5.34%	2.34%
Apr-01	7.94%	5.65%	2.29%
May-01	7.99%	5.78%	2.21%
Jun-01	7.85%	5.67%	2.18%
Jul-01	7.78%	5.61%	2.17%
Aug-01	7.59%	5.48%	2.11%
Sep-01	7.75%	5.48%	2.27%
Oct-01	7.63%	5.32%	2.31%
Nov-01	7.57%	5.12%	2.45%
Dec-01	7.83%	5.48%	2.35%
Jan-02	7.66%	5.45%	2.21%
Feb-02	7.54%	5.40%	2.14%
Mar-02	7.76%		
Apr-02	7.57%		
May-02	7.52%		
Jun-02	7.42%		
Jul-02	7.31%		
Aug-02	7.17%		
Sep-02	7.08%		
Oct-02	7.23%		
Nov-02	7.14%		
Dec-02	7.07%		
Jan-03	7.07%		
Feb-03	6.93%		
Mar-03	6.79%		
Apr-03	6.64%		
May-03	6.36%		
Jun-03	6.21%		
Jul-03	6.57%		
Aug-03	6.78%		
Sep-03	6.56%		
Oct-03	6.43%		
Nov-03	6.37%		
Dec-03	6.27%		
Jan-04	6.15%		
Feb-04	6.15%		
Mar-04	5.97%		
Apr-04	6.35%		
May-04	6.62%		
Jun-04	6.46%		
Jul-04	6.27%		
Aug-04	6.14%		
Sep-04	5.98%		
Oct-04	5.94%		
Nov-04	5.97%		
Dec-04	5.92%		

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-05	5.78%		
Feb-05	5.61%		
Mar-05	5.83%		
Apr-05	5.64%		
May-05	5.53%		
Jun-05	5.40%		
Jul-05	5.51%		
Aug-05	5.50%		
Sep-05	5.52%		
Oct-05	5.79%		
Nov-05	5.88%		
Dec-05	5.80%		
Jan-06	5.75%		
Feb-06	5.82%	4.54%	1.28%
Mar-06	5.98%	4.73%	1.25%
Apr-06	6.29%	5.06%	1.23%
May-06	6.42%	5.20%	1.22%
Jun-06	6.40%	5.15%	1.25%
Jul-06	6.37%	5.13%	1.24%
Aug-06	6.20%	5.00%	1.20%
Sep-06	6.00%	4.85%	1.15%
Oct-06	5.98%	4.85%	1.13%
Nov-06	5.80%	4.69%	1.11%
Dec-06	5.81%	4.68%	1.13%
Jan-07	5.96%	4.85%	1.11%
Feb-07	5.90%	4.82%	1.08%
Mar-07	5.85%	4.72%	1.13%
Apr-07	5.97%	4.87%	1.10%
May-07	5.99%	4.90%	1.09%
Jun-07	6.30%	5.20%	1.10%
Jul-07	6.25%	5.11%	1.14%
Aug-07	6.24%	4.93%	1.31%
Sep-07	6.18%	4.79%	1.39%
Oct-07	6.11%	4.77%	1.34%
Nov-07	5.97%	4.52%	1.45%
Dec-07	6.16%	4.53%	1.63%
Jan-08	6.02%	4.33%	1.69%
Feb-08	6.21%	4.52%	1.69%
Mar-08	6.21%	4.39%	1.82%
Apr-08	6.29%	4.44%	1.85%
May-08	6.28%	4.60%	1.68%
Jun-08	6.38%	4.69%	1.69%
Jul-08	6.40%	4.57%	1.83%
Aug-08	6.37%	4.50%	1.87%
Sep-08	6.49%	4.27%	2.22%
Oct-08	7.56%	4.17%	3.39%
Nov-08	7.60%	4.00%	3.60%
Dec-08	6.52%	2.87%	3.65%
Jan-09	6.39%	3.13%	3.26%
Feb-09	6.30%	3.59%	2.71%
Mar-09	6.42%	3.64%	2.78%
Apr-09	6.48%	3.76%	2.72%
May-09	6.49%	4.23%	2.26%
Jun-09	6.20%	4.52%	1.68%
Jul-09	5.97%	4.41%	1.56%
Aug-09	5.71%	4.37%	1.34%
Sep-09	5.53%	4.19%	1.34%
Oct-09	5.55%	4.19%	1.36%
Nov-09	5.64%	4.31%	1.33%
Dec-09	5.79%	4.49%	1.30%
Jan-10	5.77%	4.60%	1.17%
Feb-10	5.87%	4.62%	1.25%
Mar-10	5.84%	4.64%	1.20%
Apr-10	5.81%	4.69%	1.12%
May-10	5.50%	4.29%	1.21%
Jun-10	5.46%	4.13%	1.33%
Jul-10	5.26%	3.99%	1.27%
Aug-10	5.01%	3.80%	1.21%
Sep-10	5.01%	3.77%	1.24%
Oct-10	5.10%	3.87%	1.23%
Nov-10	5.37%	4.19%	1.18%
Dec-10	5.56%	4.42%	1.14%

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-11	5.57%	4.52%	1.05%
Feb-11	5.68%	4.65%	1.03%
Mar-11	5.56%	4.51%	1.05%
Apr-11	5.55%	4.50%	1.05%
May-11	5.32%	4.29%	1.03%
Jun-11	5.26%	4.23%	1.03%
Jul-11	5.27%	4.27%	1.00%
Aug-11	4.69%	3.65%	1.04%
Sep-11	4.48%	3.18%	1.30%
Oct-11	4.52%	3.13%	1.39%
Nov-11	4.25%	3.02%	1.23%
Dec-11	4.33%	2.98%	1.35%
Jan-12	4.34%	3.03%	1.31%
Feb-12	4.36%	3.11%	1.25%
Mar-12	4.48%	3.28%	1.20%
Apr-12	4.40%	3.18%	1.22%
May-12	4.20%	2.93%	1.27%
Jun-12	4.08%	2.70%	1.38%
Jul-12	3.93%	2.59%	1.34%
Aug-12	4.00%	2.77%	1.23%
Sep-12	4.02%	2.88%	1.14%
Oct-12	3.91%	2.90%	1.01%
Nov-12	3.84%	2.80%	1.04%
Dec-12	4.00%	2.88%	1.12%
Jan-13	4.15%	3.08%	1.07%
Feb-13	4.18%	3.17%	1.01%
Mar-13	4.20%	3.16%	1.04%
Apr-13	4.00%	2.93%	1.07%
May-13	4.17%	3.11%	1.06%
Jun-13	4.53%	3.40%	1.13%
Jul-13	4.68%	3.61%	1.07%
Aug-13	4.73%	3.76%	0.97%
Sep-13	4.80%	3.79%	1.01%
Oct-13	4.70%	3.68%	1.02%
Nov-13	4.77%	3.80%	0.97%
Dec-13	4.81%	3.89%	0.92%
Jan-14	4.63%	3.77%	0.86%
Feb-14	4.53%	3.66%	0.87%
Mar-14	4.51%	3.62%	0.89%
Apr-14	4.41%	3.52%	0.89%
May-14	4.26%	3.39%	0.87%
Jun-14	4.29%	3.42%	0.87%
Jul-14	4.23%	3.33%	0.90%
Aug-14	4.13%	3.20%	0.93%
Sep-14	4.24%	3.26%	0.98%
Oct-14	4.06%	3.04%	1.02%
Nov-14	4.09%	3.04%	1.05%
Dec-14	3.95%	2.83%	1.12%
Jan-15	3.58%	2.46%	1.12%
Feb-15	3.67%	2.57%	1.10%
Mar-15	3.74%	2.63%	1.11%
Apr-15	3.75%	2.59%	1.16%
May-15	4.17%	2.96%	1.21%
Jun-15	4.39%	3.11%	1.28%
Jul-15	4.40%	3.07%	1.33%
Aug-15	4.25%	2.86%	1.39%
Sep-15	4.39%	2.95%	1.44%
Oct-15	4.29%	2.89%	1.40%
Nov-15	4.40%	3.03%	1.37%
Dec-15	4.35%	2.97%	1.38%
Jan-16	4.27%	2.86%	1.41%
Feb-16	4.11%	2.62%	1.49%
Mar-16	4.16%	2.68%	1.48%
Apr-16	4.00%	2.62%	1.38%
May-16	3.93%	2.63%	1.30%
Jun-16	3.78%	2.45%	1.33%
Jul-16	3.57%	2.23%	1.34%
Aug-16	3.59%	2.26%	1.33%
Sep-16	3.66%	2.35%	1.31%
Oct-16	3.77%	2.50%	1.27%
Nov-16	4.08%	2.86%	1.22%
Dec-16	4.27%	3.11%	1.16%

Year	A-rated Public Utility	30-Year Treasuries Yield	Spread
Jan-17	4.14%	3.02%	1.12%
Feb-17	4.18%	3.03%	1.15%
Mar-17	4.23%	3.08%	1.15%
Apr-17	4.12%	2.94%	1.18%
May-17	4.12%	2.96%	1.16%
Jun-17	3.94%	2.80%	1.14%
Jul-17	3.99%	2.88%	1.11%
Aug-17	3.86%	2.80%	1.06%
Sep-17	3.87%	2.78%	1.09%
Oct-17	3.91%	2.88%	1.03%
Nov-17	3.83%	2.80%	1.03%
Dec-17	3.79%	2.77%	1.02%
Jan-18	3.86%	2.88%	0.98%
Feb-18	4.09%	3.13%	0.96%
Mar-18	4.13%	3.09%	1.04%
Apr-18	4.17%	3.07%	1.10%
May-18	4.28%	3.13%	1.15%
Jun-18	4.27%	3.05%	1.22%
Jul-18	4.27%	3.01%	1.26%
Aug-18	4.26%	3.04%	1.22%
Sep-18	4.32%	3.15%	1.17%
Oct-18	4.45%	3.34%	1.11%
Nov-18	4.52%	3.36%	1.16%
Dec-18	4.37%	3.10%	1.27%
Jan-19	4.35%	3.04%	1.31%
Feb-19	4.25%	3.02%	1.23%
Mar-19	4.16%	2.98%	1.18%
Apr-19	4.08%	2.94%	1.14%
May-19	3.98%	2.82%	1.16%
Jun-19	3.82%	2.57%	1.25%
Jul-19	3.69%	2.57%	1.12%
Aug-19	3.29%	2.12%	1.17%
Sep-19	3.37%	2.16%	1.21%
Oct-19	3.39%	2.19%	1.20%
Nov-19	3.43%	2.28%	1.15%
Dec-19	3.40%	2.30%	1.10%
Jan-20	3.29%	2.22%	1.07%
Feb-20	3.11%	1.97%	1.14%
Mar-20	3.50%	1.46%	2.04%
Apr-20	3.19%	1.27%	1.92%
May-20	3.14%	1.38%	1.76%
Jun-20	3.07%	1.49%	1.58%
Jul-20	2.74%	1.31%	1.43%
Aug-20	2.73%	1.36%	1.37%
Sep-20	2.84%	1.42%	1.42%
Oct-20	2.95%	1.57%	1.38%
Nov-20	2.85%	1.62%	1.23%
Dec-20	2.77%	1.67%	1.10%
Jan-21	2.91%	1.82%	1.09%
Feb-21	3.09%	2.04%	1.05%
Mar-21	3.44%	2.34%	1.10%
Apr-21	3.30%	2.30%	1.00%
May-21	3.33%	2.32%	1.01%
Jun-21	3.16%	2.16%	1.00%
Jul-21	2.95%	1.94%	1.01%
Aug-21	2.95%	1.92%	1.03%
Sep-21	2.96%	1.94%	1.02%
Average:	12-months		1.09%
	6-months		1.01%
	3-months		1.02%

Common Equity Risk Premiums
Years 1926-2020

	Large Common Stocks	Long-Term Corp. Bonds	Equity Risk Premium	Long-Term Govt. Bonds Yields
Low Interest Rates	12.06%	5.43%	6.63%	2.85%
Average Across All Interest Rates	12.16%	6.49%	5.67%	4.95%
High Interest Rates	12.26%	7.57%	4.69%	7.09%

Source of Information: 2021 SBBI Yearbook Stocks, Bonds, Bills, and Inflation

Basic Series
Annual Total Returns (except yields)

Year	Large Common Stocks	Long-Term Corp. Bonds	Long-Term Govt. Bonds Yields
2020	18.40%	15.40%	1.37%
1940	-9.78%	3.39%	1.94%
1945	36.44%	4.08%	1.99%
1941	-11.59%	2.73%	2.04%
1949	18.79%	3.31%	2.09%
1946	-8.07%	1.72%	2.12%
1950	31.71%	2.12%	2.24%
2019	31.49%	19.95%	2.25%
1939	-0.41%	3.97%	2.26%
1948	5.50%	4.14%	2.37%
1947	5.71%	-2.34%	2.43%
1942	20.34%	2.60%	2.46%
1944	19.75%	4.73%	2.46%
2012	16.00%	10.68%	2.46%
2014	13.69%	17.28%	2.46%
1943	25.90%	2.83%	2.48%
1938	31.12%	6.13%	2.52%
2017	21.83%	12.25%	2.54%
1936	33.92%	6.74%	2.55%
2011	2.11%	17.95%	2.55%
2015	1.38%	-1.02%	2.68%
1951	24.02%	-2.69%	2.69%
1954	52.62%	5.39%	2.72%
2016	11.96%	6.70%	2.72%
1937	-35.03%	2.75%	2.73%
1953	-0.99%	3.41%	2.74%
1935	47.67%	9.61%	2.76%
1952	18.37%	3.52%	2.79%
2018	-4.38%	-4.73%	2.84%
1934	-1.44%	13.84%	2.93%
1955	31.56%	0.48%	2.95%
2008	-37.00%	8.78%	3.03%
1932	-8.19%	10.82%	3.15%
1927	37.49%	7.44%	3.17%
1957	-10.78%	8.71%	3.23%
1930	-24.90%	7.98%	3.30%
1933	53.99%	10.38%	3.36%
1928	43.61%	2.84%	3.40%
1929	-8.42%	3.27%	3.40%
1956	6.56%	-6.81%	3.45%
1926	11.62%	7.37%	3.54%
2013	32.39%	-7.07%	3.78%
1960	0.47%	9.07%	3.80%
1958	43.36%	-2.22%	3.82%
1962	-8.73%	7.95%	3.95%
1931	-43.34%	-1.85%	4.07%
2010	15.06%	12.44%	4.14%
1961	26.89%	4.82%	4.15%
1963	22.80%	2.19%	4.17%
1964	16.48%	4.77%	4.23%
1959	11.96%	-0.97%	4.47%
1965	12.45%	-0.46%	4.50%
2007	5.49%	2.60%	4.50%
1966	-10.06%	0.20%	4.55%
2009	26.46%	3.02%	4.58%
2005	4.91%	5.87%	4.61%
2002	-22.10%	16.33%	4.84%
2004	10.88%	8.72%	4.84%
2006	15.79%	3.24%	4.91%
2003	28.68%	5.27%	5.11%
1998	28.58%	10.76%	5.42%
1967	23.98%	-4.95%	5.56%
2000	-9.10%	12.87%	5.58%
2001	-11.89%	10.65%	5.75%
1971	14.30%	11.01%	5.97%
1968	11.06%	2.57%	5.98%
1972	18.99%	7.26%	5.99%
1997	33.36%	12.95%	6.02%
1995	37.58%	27.20%	6.03%
1970	3.86%	18.37%	6.48%
1993	10.08%	13.19%	6.54%
1996	22.96%	1.40%	6.73%
1999	21.04%	-7.45%	6.82%
1969	-8.50%	-8.09%	6.87%
1976	23.93%	18.65%	7.21%
1973	-14.69%	1.14%	7.26%
1992	7.62%	9.39%	7.26%
1991	30.47%	19.89%	7.30%
1974	-26.47%	-3.06%	7.60%
1986	18.67%	19.85%	7.89%
1994	1.32%	-5.76%	7.99%
1977	-7.16%	1.71%	8.03%
1975	37.23%	14.64%	8.05%
1989	31.69%	16.23%	8.16%
1990	-3.10%	6.78%	8.44%
1978	6.57%	-0.07%	8.98%
1988	16.61%	10.70%	9.19%
1987	5.25%	-0.27%	9.20%
1985	31.73%	30.09%	9.56%
1979	18.61%	-4.18%	10.12%
1982	21.55%	42.56%	10.95%
1984	6.27%	16.86%	11.70%
1983	22.56%	6.26%	11.97%
1980	32.50%	-2.76%	11.99%
1981	-4.92%	-1.24%	13.34%

Yields for Treasury Constant Maturities
Yearly for 2016-2020
and the Twelve Months Ended September 2021

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
2016	0.61%	0.84%	1.01%	1.34%	1.64%	1.84%	2.23%	2.60%
2017	1.20%	1.40%	1.58%	1.91%	2.16%	2.33%	2.65%	2.90%
2018	2.33%	2.53%	2.63%	2.75%	2.85%	2.91%	3.02%	3.11%
2019	2.05%	1.97%	1.94%	1.96%	2.05%	2.14%	2.40%	2.58%
2020	0.38%	0.40%	0.43%	0.54%	0.73%	0.89%	1.35%	1.56%
Five-Year Average	1.31%	1.43%	1.52%	1.70%	1.89%	2.02%	2.33%	2.55%
Months								
Oct-20	0.13%	0.15%	0.19%	0.34%	0.55%	0.79%	1.34%	1.57%
Nov-20	0.12%	0.17%	0.22%	0.39%	0.63%	0.87%	1.40%	1.62%
Dec-20	0.10%	0.14%	0.19%	0.39%	0.66%	0.93%	1.47%	1.67%
Jan-21	0.10%	0.13%	0.20%	0.45%	0.77%	1.08%	1.63%	1.82%
Feb-21	0.07%	0.12%	0.21%	0.54%	0.91%	1.26%	1.88%	2.04%
Mar-21	0.08%	0.15%	0.32%	0.82%	1.27%	1.61%	2.24%	2.34%
Apr-21	0.06%	0.16%	0.35%	0.86%	1.31%	1.64%	2.20%	2.30%
May-21	0.05%	0.16%	0.32%	0.82%	1.28%	1.62%	2.22%	2.32%
Jun-21	0.07%	0.20%	0.39%	0.84%	1.23%	1.52%	2.09%	2.16%
Jul-21	0.08%	0.22%	0.40%	0.76%	1.07%	1.32%	1.87%	1.94%
Aug-21	0.07%	0.22%	0.42%	0.77%	1.06%	1.28%	1.83%	1.92%
Sep-21	0.08%	0.24%	0.47%	0.86%	1.16%	1.37%	1.87%	1.94%
Twelve-Month Average	0.08%	0.17%	0.31%	0.65%	0.99%	1.27%	1.84%	1.97%
Six-Month Average	0.07%	0.20%	0.39%	0.82%	1.19%	1.46%	2.01%	2.10%
Three-Month Average	0.08%	0.23%	0.43%	0.80%	1.10%	1.32%	1.86%	1.93%

Measures of the Risk-Free Rate & Corporate Bond Yields

The forecast of Treasury and Corporate yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated June 1, 2021 and October 1, 2021

		Treasury					Corporate	
Year	Quarter	1-Year Bill	2-Year Note	5-Year Note	10-Year Note	30-Year Bond	Aaa Bond	Baa Bond
2021	Fourth	0.1%	0.3%	1.0%	1.5%	2.2%	2.9%	3.6%
2022	First	0.2%	0.4%	1.1%	1.7%	2.3%	3.0%	3.8%
2022	Second	0.2%	0.5%	1.2%	1.8%	2.4%	3.1%	4.0%
2022	Third	0.3%	0.5%	1.3%	1.9%	2.5%	3.2%	4.1%
2022	Fourth	0.4%	0.7%	1.4%	2.0%	2.6%	3.3%	4.2%
2023	First	0.5%	0.8%	1.5%	2.1%	2.7%	3.4%	4.3%
Long-range CONSENSUS								
2022		0.3%	0.5%	1.2%	2.0%	2.6%	3.3%	4.3%
2023		0.7%	0.9%	1.6%	2.4%	2.9%	3.7%	4.7%
2024		1.2%	1.5%	2.1%	2.7%	3.3%	4.1%	5.1%
2025		1.8%	2.0%	2.5%	3.0%	3.6%	4.5%	5.4%
2026		2.1%	2.3%	2.8%	3.2%	3.8%	4.7%	5.6%
2027		2.3%	2.5%	2.8%	3.3%	3.8%	4.7%	5.7%
Averages:								
	2023-2027	1.6%	1.8%	2.4%	2.9%	3.5%	4.3%	5.3%
	2028-2032	2.4%	2.6%	3.0%	3.3%	3.9%	4.8%	5.8%

Measures of the Market Premium

Value Line Return

As of:	Dividend Yield		Median Appreciation Potential		Median Total Return
1-Oct-21	1.9%	+	8.78%	=	10.68%

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
1.41%	(	1.070	)	+	14.0%	=	15.51%

Summary

Value Line			10.68%
S&P 500			15.51%
Average			13.10%
Risk-free Rate of Return (Rf)			2.75%
Forecast Market Premium			10.35%
Historical Market Premium			
Low Interest Rates	(Rm)	(Rf)	
1926-2020 Arith. mean	12.06%	2.85%	9.21%
Average - Forecast/Historical			9.78%

Exhibit 7.8: Size-Decile Portfolios of the NYSE/NYSE MKT/NASDAQ Long-Term Returns in Excess of CAPM
1926–2016

Size Grouping	OLS Beta	Arithmetic Mean	Return in Excess of Risk-free Rate (actual)	Return in Excess of Risk-free Rate (as predicted by CAPM)	Size Premium
Mid-Cap (3–5)	1.12	13.82%	8.80%	7.79%	1.02%
Low-Cap (6–8)	1.22	15.26%	10.24%	8.49%	1.75%
Micro-Cap (9–10)	1.35	18.04%	13.02%	9.35%	3.67%
Breakdown of Deciles 1–10					
1-Largest	0.92	11.05%	6.04%	6.38%	-0.35%
2	1.04	12.82%	7.81%	7.19%	0.61%
3	1.11	13.57%	8.55%	7.66%	0.89%
4	1.13	13.80%	8.78%	7.80%	0.98%
5	1.17	14.62%	9.60%	8.09%	1.51%
6	1.17	14.81%	9.79%	8.14%	1.66%
7	1.25	15.41%	10.39%	8.67%	1.72%
8	1.30	16.14%	11.12%	9.04%	2.08%
9	1.34	16.97%	11.96%	9.28%	2.68%
10-Smallest	1.39	20.27%	15.25%	9.66%	5.59%

Betas are estimated from monthly returns in excess of the 30-day U.S. Treasury bill total return, January 1926–December 2016. Historical riskless rate measured by the 91-year arithmetic mean income return component of 20-year government bonds (5.02%). Calculated in the context of the CAPM by multiplying the equity risk premium by beta. The equity risk premium is estimated by the arithmetic mean total return of the S&P 500 (11.95%) minus the arithmetic mean income return component of 20-year government bonds (5.02%) from 1926–2016. Source: Morningstar *Direct* and CRSP. Calculated based on data from CRSP US Stock Database and CRSP US Indices Database ©2017 Center for Research. Used with permission. All calculations performed by Duff & Phelps, LLC.

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 2,3,4 & 5; Safety Rank of 1,2 & 3; Financial Strength of B+, B++, A & A+;
Price Stability of 70 to 95; Betas of .80 to 1.05; and Technical Rank of 2,3,4 & 5

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
AAON Inc	Machinery	3	3	B+	75	0.85	3
AbbVie Inc	Drug	3	3	A	75	1.00	3
ACI Worldwide Inc	IT Services	2	3	B+	70	1.00	4
Agilent Technologies	Precision Instrument	2	2	A	95	0.90	4
Alamo Group	Machinery	2	3	B+	75	1.05	3
Altria Group Inc	Tobacco	4	3	B+	85	0.95	3
AMERCO	Trucking	3	2	B+	90	0.95	3
AmerisourceBergen Corp	Med Supp Non-Invasive	2	2	A	75	0.90	3
Amphenol Corp	Electronics	3	1	A	95	1.00	4
Analog Devices Inc	Semiconductor	2	1	A+	90	0.95	3
AO Smith Corp	Machinery	3	2	B+	95	0.85	2
Archer Daniels Midland Company	Food Processing	4	1	A+	90	1.00	3
Assurant Inc	Financial Svcs. (Div.)	3	2	A	90	0.90	3
Ball Corp	Packaging & Container	3	2	B+	85	1.00	4
Bio-Techne Corp.	Biotechnology	3	2	A	75	0.85	4
Booz Allen Hamilton Holding Corporatio	Industrial Services	3	3	B+	80	0.90	3
Brady Corp	Diversified Co.	4	3	B+	85	0.95	3
Broadridge Fin'l	Information Services	3	2	B+	95	0.85	2
Brown Forman Corp (Class B)	Beverage	5	1	A	90	0.90	4
BWX Technologies	Power	3	3	B+	75	0.90	5
CACI International Inc	IT Services	3	3	B+	85	0.95	2
Caseys General Stores Inc	Retail/Wholesale Food	3	3	B+	80	0.90	4
Cboe Global Markets	Brokers & Exchanges	3	2	A	85	0.90	2
CDW Corp.	IT Services	2	3	B+	85	1.05	3
Chemed Corporation	Diversified Co.	3	2	A	95	0.85	4
Cognizant Technology Solutions Corp	IT Services	5	2	A+	80	1.00	3
Commerce Bancshares Inc	Bank (Midwest)	4	1	A	90	0.90	2
Cooper Companies Inc	Med Supp Non-Invasive	4	2	A	90	0.95	3
Copart Inc	Retail Automotive	2	2	A	75	1.00	4
CoStar Group Inc	Information Services	3	2	A+	80	0.85	4
Crown Castle International Corporation	Wireless Networking	3	2	A	90	0.85	3
CVS Caremark Corporation	Retail Store	3	2	A+	70	0.95	3
Dolby Laboratories Inc	Entertainment Tech	2	2	A	90	0.95	2
Encore Wire	Electronics	3	3	A	75	0.95	3
ESCO Technologies Inc	Diversified Co.	3	3	B+	85	1.00	3
Estee Lauder Companies Inc	Toiletries/Cosmetics	3	2	A	85	0.95	2
Expeditors International of Washington I	Industrial Services	3	1	A+	95	0.95	3
Exponent Inc.	Information Services	3	3	B+	90	0.90	4
F5 Networks	Telecom. Equipment	4	3	A	75	0.95	3
FactSet Research Systems Inc	Information Services	5	1	A+	90	1.00	4
Fastenal Co	Retail Building Supply	5	2	A+	80	0.95	3
Federal Signal Corp	Heavy Truck & Equip	3	3	B+	75	1.00	3
FirstCash Inc.	Financial Svcs. (Div.)	4	3	B+	80	0.90	4
FleetCor Technologies Inc	Financial Svcs. (Div.)	2	3	B+	70	1.05	4
Forward Air Corp	Trucking	2	3	B+	80	1.00	2
Franklin Electric Co Inc	Electrical Equipment	2	2	A	80	0.95	3
GATX Corp	Railroad	3	3	B+	80	0.95	3
Gentex Corp	Auto Parts	3	2	B+	90	0.95	3
Globus Medical Inc	Med Supp Invasive	3	3	B+	70	0.80	3
Graphic Packaging	Packaging & Container	3	3	B+	80	1.00	3
Harris Corp.	Aerospace/Defense	3	2	A+	75	0.95	2
Hershey Company	Food Processing	3	1	A+	95	0.85	3
IDEX Corporation	Machinery	2	2	B+	95	1.05	2
IDEXX Laboratories Inc	Med Supp Non-Invasive	3	3	A	75	1.00	3
Ingredion Incorporated	Food Processing	4	2	B+	90	0.95	3
Innospec Inc	Chemical (Specialty)	4	3	B+	75	1.05	2
Intuit Inc	Computer Software	2	2	A+	80	1.00	4
Iron Mountain Inc	Industrial Services	4	3	B+	80	0.90	2
J B Hunt Transport Services Inc	Trucking	3	1	A+	85	0.95	3
Jack Henry and Associates Inc	IT Services	3	1	A+	90	0.85	2
Juniper Networks Inc	Telecom. Equipment	4	2	A	85	1.00	3
Lennox International Inc	Machinery	3	3	B+	90	1.00	2
Lindsay Corporation	Machinery	2	3	B+	80	0.85	2
ManTech International Corporation	IT Services	3	3	B+	85	0.85	3
Masimo Corporation	Med Supp Non-Invasive	4	2	A	70	0.80	3
McCormick and Co	Food Processing	3	1	A+	95	0.80	5
Mercury General Corp	Insurance (Prop/Cas.)	4	3	B+	75	0.90	3
Monster Beverage Corporation	Beverage	2	2	A+	90	0.85	3
Motorola Solutions Inc	Telecom. Equipment	3	2	B+	90	0.90	3
MSA Safety	Machinery	3	2	A	80	1.00	3
MSC Industrial Direct Co Inc	Machinery	3	2	A	75	0.95	2
MSCI Inc	Information Services	2	3	B+	85	0.95	4
Nasdaq Inc.	Brokers & Exchanges	3	1	A+	90	1.05	4
Neogen Corp	Med Supp Non-Invasive	3	3	B+	70	0.80	3
Northwest Bancshares Inc	Thrift	3	3	B+	95	0.95	3
O Reilly Automotive Inc	Retail Automotive	3	3	B+	75	0.95	3
Old National Bancorp	Bank (Midwest)	4	3	B+	80	1.00	3
Omnicom Group Inc	Advertising	4	3	B+	85	1.00	3
Packaging Corp	Packaging & Container	2	2	A	85	0.95	2
Park National Corp	Bank (Midwest)	3	3	B+	80	0.80	3
PerkinElmer Inc	Precision Instrument	2	2	B+	85	0.90	3
Philip Morris International Inc	Tobacco	3	3	B+	75	0.95	3
Plexus Corp	Electronics	4	3	B+	80	1.05	4
Pool Corporation	Recreation	2	2	A	80	0.85	3
Progressive Corp.	Insurance (Prop/Cas.)	2	1	A	95	0.80	3
Quest Diagnostics Inc	Medical Services	4	2	B+	90	0.85	3
Rayonier Inc	Paper/Forest Products	3	3	B+	90	1.05	3
RLI Corp	Insurance (Prop/Cas.)	2	2	A	90	0.80	3
Rollins Inc	Industrial Services	3	2	A	90	0.85	3
Roper Tech.	Machinery	2	1	A+	95	1.00	3
Scholastic Corporation	Publishing	4	3	B+	70	1.00	3
Sensient Technologies Corp	Food Processing	3	2	B+	95	0.90	3
Sherwin Williams	Retail Building Supply	4	1	A+	90	0.95	3
Sonoco Products	Packaging & Container	4	2	A	95	1.00	2
Standard Motor Products Inc	Auto Parts	3	3	B+	75	0.85	4
Stepan Company	Chemical (Specialty)	3	3	B+	75	0.80	3
Synopsys Inc	Computer Software	2	1	A+	85	0.95	4
T Rowe Price Group Inc	Asset Management	2	1	A+	85	1.05	2
Tetra Tech	Environmental	3	3	B+	80	0.95	4
Thermo Fisher Scientific Inc	Precision Instrument	2	1	A	95	0.85	4
Toro Co	Machinery	3	2	B+	90	1.05	2
Trimas Corporation	Diversified Co.	4	3	B+	80	0.85	3
UniFirst Corp	Industrial Services	4	2	A	85	0.95	3
United Parcel Service	Air Transport	3	1	A+	85	0.80	3
Vail Resorts	Hotel/Gaming	2	3	B+	75	0.95	3
Valmont Industries	Diversified Co.	2	2	A	80	1.05	3
Viavi Solutions	Electronics	4	3	B+	70	0.95	3
Walgreens Boots	Retail Store	3	3	A	75	0.85	3
Washington Federal Inc	Thrift	3	3	B+	75	1.05	3
Waters Corp	Precision Instrument	3	2	A	90	0.95	3
Watsco Inc	Retail Building Supply	3	1	A+	95	0.85	3
West Pharmaceutical Services Inc	Med Supp Non-Invasive	4	2	A	85	0.80	4
Western Union Company	Financial Svcs. (Div.)	5	3	B+	95	0.80	3
Wiley John and Sons Inc (Class A)	Publishing	3	3	B+	75	0.85	3
Xylem Inc	Machinery	2	2	B+	85	1.05	3
Yum Brands Inc	Restaurant	4	2	B+	90	1.05	2
Zoetis Inc	Drug	3	2	B+	90	1.00	3
Average		3	2	B+	84	0.93	3
Gas Group	Average	4	2	A	87	0.88	3

Source of Information: Value Line Investment Survey for Windows, January 2021

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2016-2020 and
Projected 3-5 Year Returns

Company	2016	2017	2018	2019	2020	Average	Projected 2024-26
AAON Inc	25.9%	21.1%	17.2%	18.5%	22.5%	21.0%	22.5%
AbbVie Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
ACI Worldwide Inc	17.2%	0.7%	6.6%	5.9%	6.0%	7.3%	10.0%
Agilent Technologies	15.4%	15.9%	19.9%	20.8%	21.0%	18.6%	20.0%
Alamo Group	10.3%	12.1%	14.5%	11.0%	9.1%	11.4%	13.0%
Altria Group Inc	46.4%	42.5%	51.0%	NMF	NMF	46.6%	NMF
AMERCO	15.2%	9.0%	10.0%	7.0%	12.6%	10.8%	9.0%
AmerisourceBergen Corp	60.4%	63.2%	48.8%	52.2%	NMF	56.2%	NMF
Amphenol Corp	23.3%	24.7%	30.0%	25.5%	22.3%	25.2%	26.5%
Analog Devices Inc	18.6%	16.6%	20.4%	16.3%	15.2%	17.4%	19.0%
AO Smith Corp	21.5%	22.9%	26.2%	22.2%	18.7%	22.3%	28.0%
Archer Daniels Midland Company	7.4%	6.6%	9.5%	7.2%	8.9%	7.9%	9.5%
Assurant Inc	13.8%	12.2%	4.9%	6.8%	7.4%	9.0%	7.5%
Ball Corp	7.7%	7.7%	13.1%	19.2%	17.9%	13.1%	20.5%
Bio-Techne Corp.	11.9%	9.2%	9.8%	8.2%	11.0%	10.0%	15.5%
Booz Allen Hamilton Holding Corporation	44.0%	55.0%	58.8%	56.4%	50.8%	53.0%	30.0%
Brady Corp	13.3%	13.7%	14.9%	15.4%	13.0%	14.1%	12.5%
Broadridge Fin'l	29.4%	32.6%	46.1%	49.1%	43.7%	40.2%	34.0%
Brown Forman Corp (Class B)	48.8%	56.7%	50.7%	41.9%	29.1%	45.4%	53.0%
BWX Technologies	NMF	71.1%	96.3%	60.4%	45.1%	68.2%	38.0%
CACI International Inc	8.9%	9.1%	9.4%	11.2%	12.1%	10.1%	12.0%
Caseys General Stores Inc	14.9%	11.2%	14.5%	16.1%	16.2%	14.6%	15.5%
Cboe Global Markets	58.4%	12.9%	13.1%	11.1%	13.9%	21.9%	12.0%
CDW Corp.	40.6%	53.2%	65.9%	76.7%	60.8%	59.4%	64.5%
Chemed Corporation	20.7%	26.1%	33.9%	31.7%	32.9%	29.1%	27.0%
Cognizant Technology Solutions Corp	19.3%	21.0%	23.4%	20.3%	17.0%	20.2%	17.5%
Commerce Bancshares Inc	11.0%	11.8%	14.8%	13.4%	10.4%	12.3%	12.0%
Cooper Companies Inc	10.1%	11.7%	10.3%	12.9%	6.2%	10.2%	12.5%
Copart Inc	33.0%	27.6%	26.3%	30.1%	24.5%	28.3%	32.0%
CoStar Group Inc	8.3%	5.8%	10.0%	11.0%	7.1%	8.4%	11.0%
Crown Castle International Corporation	21.5%	3.6%	5.6%	8.2%	11.2%	10.0%	9.5%
CVS Caremark Corporation	17.2%	16.1%	12.7%	14.5%	14.2%	14.9%	12.5%
Dolby Laboratories Inc	9.4%	9.4%	12.6%	11.1%	9.5%	10.4%	13.0%
Encore Wire	5.9%	10.5%	10.8%	7.5%	9.1%	8.8%	9.5%
ESCO Technologies Inc	8.3%	8.6%	9.0%	9.9%	7.5%	8.7%	10.0%
Estee Lauder Companies Inc	31.2%	28.5%	36.2%	45.1%	38.4%	35.9%	54.0%
Expeditors International of Washington Inc	23.4%	22.7%	31.1%	26.9%	26.2%	26.1%	32.0%
Exponent Inc.	17.4%	14.3%	23.0%	23.5%	22.8%	20.2%	29.5%
F5 Networks	30.9%	34.2%	35.3%	24.3%	13.8%	27.7%	16.0%
FactSet Research Systems Inc	49.7%	46.1%	50.8%	52.5%	41.6%	48.1%	42.5%
Fastenal Co	25.8%	27.6%	32.7%	29.7%	31.4%	29.4%	41.0%
Federal Signal Corp	10.8%	11.2%	16.5%	17.2%	14.7%	14.1%	14.5%
FirstCash Inc.	4.1%	7.9%	11.6%	12.2%	8.3%	8.8%	12.0%
FleetCor Technologies Inc	21.4%	21.7%	24.3%	24.1%	21.0%	22.5%	32.5%
Forward Air Corp	13.0%	13.4%	16.6%	15.1%	9.4%	13.5%	13.5%
Franklin Electric Co Inc	12.8%	12.5%	14.6%	12.3%	12.1%	12.9%	14.5%
GATX Corp	17.6%	10.4%	11.2%	10.9%	6.5%	11.3%	9.0%
Gentex Corp	18.2%	18.0%	23.5%	21.9%	17.7%	19.9%	28.5%
Globus Medical Inc	12.5%	12.2%	13.2%	11.1%	6.8%	11.2%	12.0%
Graphic Packaging	21.6%	23.2%	11.9%	13.2%	11.7%	16.3%	22.5%
Harris Corp.	-	-	-	NMF	5.4%	5.4%	13.0%
Hershey Company	NMF	NMF	80.8%	70.1%	57.2%	69.4%	29.0%
IDEX Corporation	18.5%	17.9%	21.1%	19.6%	15.6%	18.5%	20.0%
IDEXX Laboratories Inc	-	-	-	NMF	92.0%	92.0%	38.5%
Ingredion Incorporated	20.5%	19.5%	20.8%	16.4%	13.6%	18.2%	17.0%
Innospec Inc	12.4%	7.8%	10.3%	12.2%	3.0%	9.1%	13.0%
Intuit Inc	86.5%	84.9%	62.2%	47.5%	40.6%	64.3%	21.0%
Iron Mountain Inc	13.7%	13.3%	16.8%	20.0%	30.1%	18.8%	NMF
J B Hunt Transport Services Inc	30.6%	22.6%	29.7%	24.9%	19.5%	25.5%	16.0%
Jack Henry and Associates Inc	25.0%	23.8%	22.3%	19.0%	19.1%	21.8%	23.5%
Juniper Networks Inc	12.9%	17.3%	13.8%	13.0%	11.4%	13.7%	31.0%
Lennox International Inc	812.8%	674.5%	-	NMF	NMF	743.7%	NMF
Lindsay Corporation	11.4%	8.6%	11.4%	5.8%	12.9%	10.0%	12.5%
ManTech International Corporation	4.5%	4.7%	5.9%	7.6%	7.6%	6.1%	9.0%
Masimo Corporation	21.5%	24.2%	20.0%	16.8%	17.1%	19.9%	15.5%
McCormick and Co	29.7%	21.4%	20.9%	20.8%	19.4%	22.4%	16.5%
Mercury General Corp	5.4%	5.1%	6.2%	8.0%	15.1%	8.0%	14.0%
Monster Beverage Corporation	21.4%	20.0%	27.5%	26.6%	24.6%	24.0%	23.0%
Motorola Solutions Inc	-	-	-	-	-	-	NMF
MSA Safety	18.8%	23.6%	27.7%	25.9%	22.4%	23.7%	24.5%
MSC Industrial Direct Co Inc	21.1%	18.7%	20.8%	20.0%	20.1%	79.0%	22.0%
MSCI Inc	82.1%	75.8%	-	NMF	NMF	13.8%	NMF
Nasdaq Inc.	11.4%	11.7%	14.9%	14.8%	16.0%	13.8%	10.5%
Neogen Corp	9.0%	9.3%	10.3%	9.4%	8.2%	9.2%	8.0%
Northwest Bancshares Inc	4.2%	7.6%	8.4%	8.2%	4.9%	6.7%	9.5%
O Reilly Automotive Inc	63.8%	NMF	NMF	NMF	NMF	63.8%	NMF
Old National Bancorp	7.4%	6.0%	7.1%	8.4%	7.6%	7.3%	8.0%
Omnicom Group Inc	53.1%	46.0%	52.1%	46.9%	30.7%	45.8%	28.5%
Packaging Corp	25.5%	25.0%	27.6%	22.7%	16.9%	23.5%	17.0%
Park National Corp	11.6%	11.3%	13.3%	10.6%	12.3%	11.8%	10.5%
PerkinElmer Inc	13.3%	12.9%	15.6%	16.3%	24.9%	16.6%	14.5%
Philip Morris International Inc	NMF	NMF	NMF	NMF	NMF	-	NMF
Plexus Corp	9.9%	10.9%	11.9%	12.3%	12.5%	11.5%	12.5%
Pool Corporation	72.6%	74.9%	104.9%	63.8%	57.4%	74.7%	45.0%
Progressive Corp.	11.8%	16.7%	27.2%	23.1%	26.0%	21.0%	19.5%
Quest Diagnostics Inc	15.9%	16.2%	16.8%	15.9%	22.6%	17.5%	16.5%
Rayonier Inc	15.0%	9.3%	6.6%	4.1%	2.3%	7.5%	13.5%
RLI Corp	11.3%	8.7%	11.4%	11.8%	10.4%	10.7%	11.0%
Rollins Inc	29.4%	29.2%	32.5%	24.9%	27.7%	28.7%	34.0%
Roper Tech.	11.4%	11.0%	15.9%	14.4%	12.9%	13.1%	12.0%
Scholastic Corporation	4.7%	5.0%	3.9%	2.6%	NMF	4.1%	5.5%
Sensient Technologies Corp	17.2%	17.7%	18.3%	14.2%	11.7%	15.8%	13.0%
Sherwin Williams	60.3%	38.7%	47.1%	47.9%	62.6%	51.3%	40.0%
Sonoco Products	18.1%	16.5%	19.4%	19.8%	18.2%	18.4%	17.0%
Standard Motor Products Inc	14.2%	13.5%	12.2%	13.7%	14.6%	13.6%	14.0%
Stepan Company	13.6%	12.4%	14.4%	11.6%	12.9%	13.0%	13.0%
Synopsys Inc	14.6%	16.4%	17.2%	17.2%	17.6%	16.6%	24.5%
T Rowe Price Group Inc	24.6%	26.4%	29.0%	30.0%	31.0%	28.2%	32.5%
Tetra Tech	12.8%	13.3%	15.4%	17.8%	17.0%	15.3%	22.0%
Thermo Fisher Scientific Inc	9.4%	8.8%	10.7%	11.5%	18.5%	11.8%	16.5%
Toro Co	42.0%	43.4%	40.7%	31.9%	29.6%	37.5%	40.5%
Trimas Corporation	11.6%	11.8%	13.1%	9.5%	11.8%	11.6%	14.5%
UniFirst Corp	8.5%	7.4%	10.2%	10.0%	7.8%	8.8%	8.5%
United Parcel Service	NMF	NMF	NMF	NMF	NMF	-	NMF
Vail Resorts	17.1%	13.4%	23.9%	20.1%	7.5%	16.4%	18.5%
Valmont Industries	18.4%	14.2%	16.1%	13.8%	14.8%	15.5%	14.5%
Viavi Solutions	13.1%	11.8%	14.8%	21.5%	24.1%	17.1%	15.5%
Walgreens Boots	16.8%	20.0%	23.0%	23.5%	20.2%	20.7%	21.5%
Washington Federal Inc	8.3%	8.7%	10.2%	10.3%	8.6%	9.2%	8.0%
Waters Corp	22.7%	27.0%	39.9%	39.9%	NMF	32.4%	24.0%
Watsco Inc	18.2%	15.3%	18.0%	17.1%	18.1%	17.3%	24.0%
West Pharmaceutical Services Inc	12.9%	11.8%	14.8%	15.4%	18.7%	14.7%	20.0%
Western Union Company	91.4%	-	-	NMF	416.8%	254.1%	NMF
Wiley John and Sons Inc (Class A)	17.4%	16.6%	14.2%	NMF	13.6%	15.5%	14.0%
Xylem Inc	11.9%	17.1%	18.9%	18.5%	12.6%	15.8%	13.5%
Yum Brands Inc	-	-	-	-	-	-	NMF
Zoetis Inc	65.4%	66.8%	69.8%	64.8%	48.9%	63.1%	44.5%
Average						31.3%	20.2%
Median						16.6%	16.0%
Average (excluding companies with values >20%)						12.5%	12.9%

Comparable Earnings Approach
Screening Parameters

Timeliness Rank

The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

BOOK VI

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT C (FULLY PROJECTED FUTURE)

2023 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2023

Witness: John F. Wiedmayer
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 Effective: March 29, 2022

UGI Gas Exhibit C (Fully Projected Future)
Witness: J. F. Wiedmayer

UGI UTILITIES, INC. – GAS DIVISION

DOCKET NO. R-2021-3030218

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AT SEPTEMBER 30, 2023

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AT SEPTEMBER 30, 2023

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Valley Forge, Pennsylvania

Gannett Fleming

Excellence Delivered ***As Promised***

January 6, 2022

Mr. Anton R. Hummer
Controller and Principal Accounting Officer
UGI Utilities, Inc. – Gas Division
1 UGI Drive
Denver, PA 17517

Ladies and Gentlemen:

Pursuant to your request, we have determined the annual depreciation accruals applicable to gas plant at September 30, 2023 for the consolidated UGI gas company. Summaries of the original cost, annual accruals and the book depreciation reserve are presented in Tables 1 through 4 of the attached report.

A description of the methods and procedures upon which the study was based is set forth in a companion report, UGI Gas Exhibit C (Future), “Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant at September 30, 2022”.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John F. Wiedmayer

JOHN F. WIEDMAYER, C.D.P.
Project Manager, Depreciation Studies

JFW:mle
069215.100

TABLE OF CONTENTS

PART I. INTRODUCTION

UGI UTILITIES, INC. – GAS DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for UGI Utilities, Inc. – Gas Division to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of gas plant at September 30, 2023.

BASIS OF STUDY

Depreciation

The annual depreciation accruals and accrued depreciation were calculated using the straight line method, the remaining life basis, the average service life (ASL) procedure for plant installed prior to 1982 and the equal life group procedure (ELG) for 1982 and subsequent vintages. The calculations were based on the attained ages and estimated service life characteristics for each depreciable group of gas property.

Service Life Estimates

The service life and survivor curve estimates used for the calculation of depreciation at September 30, 2023, are set forth in Table 1 and are based on company data through 2017. The service life estimates are the same estimates as submitted to the Pennsylvania Public Utility Commission (PA PUC) in the most recent service life study report in January 2019 as part of the gas rate filing.

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals at September 30, 2023, the book reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation for the average service life procedure are presented in Exhibit C (Future). The detailed calculations at September 30, 2023, are set forth in Part III of this report.

Amortization of Net Salvage

In accordance with Pennsylvania rate regulation practice, under which experienced costs of negative net salvage are amortized after their occurrence, no adjustments for expected net salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts. The annual provision for recovering negative net salvage is based on the amortization of experienced net salvage over a five-year period.

PART II. RESULTS OF STUDY

PART II. RESULTS OF STUDY

DESCRIPTION OF SUMMARY TABULATIONS

Tables 1 through 4 presented on pages II-3 through II-12 summarize the results of the depreciation study as of September 30, 2023 for the consolidated UGI gas company. Table 1 sets forth, by depreciable group, the estimated survivor curve, original cost, book depreciation reserve at September 30, 2023, future book accruals, and calculated annual accrual amount and rate. Table 2 presents the bringforward of the book reserve to September 30, 2023. Table 3 sets forth the calculation of the depreciation accruals for the twelve months ended September 30, 2023. Table 4 presents the annual amortization of experienced and estimated net salvage based on the period 2019 through 2023.

DETAILED TABULATIONS OF DEPRECIATION CALCULATIONS

Supporting data for the original cost depreciation calculations in account sequence are presented in Part III of this report. The tables indicate the estimated survivor curves used in the calculations and set forth, for each installation year, the original cost, calculated accrued depreciation, allocated book reserve, future book accruals, remaining life, and calculated remaining life accrual.

Detailed tabulations setting forth the experienced and estimated cost of removal and salvage amounts by year and account are presented in Part IV of this report. The net salvage amounts are carried forward to Table 4 which presents the five-year amortization.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2023

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
GAS PLANT							
PRODUCTION PLANT							
305 MANUFACTURED GAS PLANT SITE REMEDIATION		FULLY ACCRUED*	0	69,118	(69,118)	-	0
325.2 PRODUCING LEASEHOLDS		55 - S0.5	163,100	162,135	965	0.02	33
325.4 RIGHTS-OF-WAY		60 - R1	30,277	29,717	560	0.06	18
328 FIELD MEASURING AND REGULATING STATION STRUCTURES		FULLY ACCRUED	1,263	1,263	0	-	0
329 OTHER STRUCTURES		FULLY ACCRUED	44,785	44,783	2	-	0
330 PRODUCING GAS WELLS - WELL CONSTRUCTION		FULLY ACCRUED	18,209	18,209	0	-	0
331 PRODUCING GAS WELLS - WELL EQUIPMENT		FULLY ACCRUED	24,441	24,441	0	-	0
332 FIELD LINES		47 - L0	750,689	726,792	23,897	0.13	948
334 FIELD MEASURING AND REGULATING STATION EQUIPMENT		24 - O3	89,725	85,373	4,352	0.43	383
335 DRILLING AND CLEANING EQUIPMENT		30 - S0.5	49,604	49,503	101	0.03	16
337 OTHER EQUIPMENT		FULLY ACCRUED	11,062	11,062	0	-	0
TOTAL PRODUCTION PLANT			**1,183,155**	**1,222,396**	**(39,241)**	**0.12**	**1,398**
STORAGE PLANT							
352.01 WELL CONSTRUCTION		FULLY ACCRUED*	0	(35,934)	35,934	-	0
TOTAL STORAGE PLANT			**0**	**(35,934)**	**35,934**	-	**0**
TRANSMISSION PLANT							
365.2 RIGHTS-OF-WAY		70 - R4	868,160	548,463	319,697	1.32	11,469
366 STRUCTURES AND IMPROVEMENTS		30 - R1	162,216	147,551	14,665	0.69	1,122
367 MAINS		70 - R3	39,074,497	22,345,709	16,728,788	1.16	452,101
369 MEASURING AND REGULATING STATION EQUIPMENT		49 - R2	6,152,338	4,059,205	2,093,133	1.46	90,041
370 COMMUNICATION EQUIPMENT		23 - R0.5	3,486,136	2,244,418	1,241,718	2.80	97,784
371 OTHER EQUIPMENT		35 - R2.5	140,637	130,718	9,919	0.76	1,074
371.1 TESTING EQUIPMENT		20 - R3	210,011	157,623	52,388	2.34	4,914
TOTAL TRANSMISSION PLANT			**50,093,995**	**29,633,687**	**20,460,308**	**1.31**	**658,505**
DISTRIBUTION PLANT							
374.2 RIGHTS-OF-WAY		75 - R3	3,544,569	1,427,058	2,117,511	1.29	45,770
375 STRUCTURES AND IMPROVEMENTS		50 - S0.5	5,554,376	3,342,997	2,211,379	1.53	84,890
376.1 MAINS - PRIMARILY STEEL		73 - R2.5	646,013,547	196,479,099	449,534,448	1.51	9,755,688
376.2 MAINS - CAST IRON	09-2027	65 - R1	1,459,008	(195,436)	1,654,444	29.73	433,809
376.3 MAINS - PLASTIC		67 - R3	1,746,351,333	309,834,305	1,436,517,028	1.66	29,069,896
376.5 MAINS - PRIMARILY WROUGHT IRON	09-2041	70 - R1	274,912	217,498	57,414	2.25	6,174
376.7 REG AFUDC		5 - SQ	1,322,088	662,477	659,611	19.96	263,844
378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		47 - S0	189,362,927	28,860,503	160,502,424	3.03	5,742,764
379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		45 - R2	25,635,909	9,033,447	16,602,462	2.36	604,614
380 SERVICES		46 - S1	1,452,368,108	425,136,757	1,027,231,351	2.49	36,128,070
381 METERS		35 - R2	161,031,938	58,594,291	102,437,647	3.12	5,023,122
381.1 METERS - ERTS		17 - S3	23,249,326	19,970,658	3,278,668	2.20	511,217
382 METER INSTALLATIONS		46 - S1	108,482,793	38,252,514	70,230,279	2.38	2,578,138
383 HOUSE REGULATORS		46 - S1	10,725,462	7,112,846	3,612,616	1.37	146,788
384 HOUSE REGULATOR INSTALLATIONS		46 - S1	18,953,576	9,351,213	9,602,363	1.98	375,664
385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		45 - R2	39,907,546	18,366,647	21,540,899	2.05	817,225
386.0 OTHER PROPERTY ON CUSTOMERS PREMISES		46 - S1	68,824	(84,503)	153,327	13.54	9,319
386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS		45 - R2	953,218	678,603	274,615	1.51	14,356
386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS		25 - R3	24,705	24,705	0	-	0
387 OTHER EQUIPMENT		35 - R2.5	4,871,243	3,034,573	1,836,670	2.04	99,425
387.1 OTHER EQUIPMENT - GRAPHIC DATA BASE		25 - SQ	1,490,664	1,473,072	17,592	0.28	4,177
TOTAL DISTRIBUTION PLANT			**4,441,646,072**	**1,131,573,324**	**3,310,072,748**	**2.06**	**91,714,950**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2023

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS		VARIOUS**	131,977,661	44,037,136	87,940,526	3.59	4,731,811
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	5,052,931	1,234,708	3,818,223	5.73	289,630
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		10 - SQ	191,996	65,601	126,395	9.88	18,964
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT		5 - SQ	87,513	(17,170)	104,683	47.85	41,873
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE			0	(42,186)	42,186	-	0
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S		8 - L2.5	4,459,377	1,327,881	3,131,496	14.26	635,820
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS		10 - L2.5	34,331,534	9,350,144	24,981,390	11.65	3,999,294
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES		12 - L3	3,920,885	1,181,222	2,739,663	8.94	350,432
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS		12 - L3	6,059,000	1,790,761	4,268,239	8.91	539,714
392.5	TRANSPORTATION EQUIPMENT - TRAILERS		15 - L2	2,767,856	772,421	1,995,435	7.63	211,111
393	STORES EQUIPMENT		20 - SQ	17,606	7,199	10,407	4.74	834
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	40,199,606	14,190,646	26,008,960	5.17	2,080,239
395	LABORATORY EQUIPMENT		20 - SQ	437,779	134,257	303,522	5.05	22,097
396	POWER OPERATED EQUIPMENT		15 - L2	6,570,611	2,887,895	3,682,716	6.80	446,936
397	COMMUNICATION EQUIPMENT		10 - SQ	906,960	478,901	428,059	11.79	106,929
398	MISCELLANEOUS EQUIPMENT		15 - SQ	2,342,273	1,187,196	1,155,077	7.91	185,267
TOTAL GENERAL PLANT				**239,323,588**	**78,586,612**	**160,736,977**	**5.71**	**13,660,951**
TOTAL DEPRECIABLE GAS PLANT				**4,732,246,810**	**1,240,980,085**	**3,491,266,726**	**2.24**	**106,035,804**
NONDEPRECIABLE PLANT								
301	ORGANIZATION			166,478				
302	FRANCHISES AND CONSENTS			193,597				
303	MISCELLANEOUS INTANGIBLE PLANT			289,868				
304.1	LAND AND LAND RIGHTS - LAND			375,198				
304.2	LAND AND LAND RIGHTS - LAND RIGHTS			6,454				
325.1	PRODUCING LANDS			13,029				
325.5	OTHER LAND			1,134				
365.1	LAND			47,323				
374.1	LAND AND LAND RIGHTS - LAND			849,347				
374.2	LAND AND LAND RIGHTS - LAND RIGHTS			7,305,824				
389.1	LAND AND LAND RIGHTS - LAND			10,369,472				
389.2	LAND AND LAND RIGHTS - LAND RIGHTS			1,313				
TOTAL NONDEPRECIABLE PLANT				**19,619,037**				
TOTAL GAS PLANT				**4,751,865,847**				

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2023

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
<u>OTHER UTILITY PLANT</u>							
COMMON PLANT							
301 ORGANIZATION (NONDEPRECIABLE)			138,964				
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108				
390.1 STRUCTURES AND IMPROVEMENTS	01-2069	70 - R1	34,840,807	3,951,151	30,889,656	2.77	965,770
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY			0	0	0	-	0
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,360,642	1,240,166	3,120,476	5.33	232,212
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	1,353,590	737,137	616,453	20.16	272,818
392.1 TRANSPORTATION EQUIPMENT - CARS		7 - L2.5	71,637	71,637	0	-	0
398 MISCELLANEOUS EQUIPMENT		10 - SQ	27,967	7,091	20,876	11.48	3,212
TOTAL COMMON PLANT			**47,740,715**	**6,007,182**	**34,647,461**	**3.63**	**1,474,012**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 88.97%			**42,474,914**	**5,344,590**	**30,825,846**		**1,311,428**
INFORMATION SERVICES (IS)							
390.1 STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER	09-2073	80 - R1.5	4,000,001	5,200	3,994,801	3.17	126,819
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	7,459	6,523	936	8.65	645
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	11,992,294	9,506,822	2,485,472	17.47	2,094,729
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE		SQUARE	13,499,682	4,435,984	9,063,698	11.00	1,484,940
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	66,371,890	15,462,616	50,909,274	10.33	6,858,130
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	131,424,308	48,452,565	82,971,743	6.74	8,856,735
TOTAL INFORMATION SERVICES			**227,295,634**	**77,869,710**	**149,425,924**	**8.54**	**19,421,998**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 91.68%			**208,384,637**	**71,390,950**	**136,993,687**		**17,806,088**
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS - UNITE ADC		15 - SQ	41,177,032	1,945,443	39,231,589	6.57	2,705,627
EMPIRE YARD BUILDING							
390.1 STRUCTURES AND IMPROVEMENTS	12-2047	80 - R1.5	14,361,971	8,421,862	5,940,109	1.88	270,430
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%			**1,877,110**	**1,100,737**	**776,372**		**35,345**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ALL GAS DIVISIONS			**290,159,473**	**77,580,246**	**206,274,750**		**21,787,798**
TOTAL PLANT IN SERVICE			**5,042,025,320**	**1,318,560,331**	**3,697,541,476**		**127,823,602**
AMORTIZATION OF NEGATIVE NET SALVAGE							*6,083,750*
GRAND TOTAL			**5,042,025,320**	**1,318,560,331**	**3,697,541,476**		**133,907,352**

* ACCOUNTS 305 AND 352.01 HAVE NO REMAINING DEPRECIATION ACCRUALS. THE FUTURE ACCRUALS SHOWN ARE RELATED TO THE AMORTIZATION OF NEGATIVE NET SALVAGE.
** SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES.INDIVIDUAL BUILDINGS ARE LIFE SPANNED.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2022 PROJECTED TO SEPTEMBER 30, 2023

ACCOUNT (1)		BOOK RESERVE AT BEGINNING OF YEAR (2)	ANNUAL ACCRUAL (3)	AMORTIZATION OF NET SALVAGE (4)	RETIREMENTS (5)	GROSS SALVAGE (6)	COST OF REMOVAL (7)	TRANSFERS AND ADJUSTMENTS (8)	BOOK RESERVE AT END OF YEAR (9)	BOOK RESERVE AS A PERCENT OF ORIGINAL COST (10)
GAS PLANT										
PRODUCTION PLANT										
305	MANUFACTURED GAS PLANT SITE REMEDIATION	92,158	0	(23,040)	0	0	0	0	69,118	0.00
325.2	PRODUCING LEASEHOLDS	162,102	33	0	0	0	0	0	162,135	99.41
325.4	RIGHTS-OF-WAY	29,699	18	0	0	0	0	0	29,717	98.15
328	FIELD MEASURING AND REGULATING STATION STRUCTURES	1,263	0	0	0	0	0	0	1,263	100.00
329	OTHER STRUCTURES	44,783	0	0	0	0	0	0	44,783	100.00
330	PRODUCING GAS WELLS - WELL CONSTRUCTION	18,209	0	0	0	0	0	0	18,209	100.00
331	PRODUCING GAS WELLS - WELL EQUIPMENT	24,441	0	0	0	0	0	0	24,441	100.00
332	FIELD LINES	725,816	976	0	0	0	0	0	726,792	96.82
334	FIELD MEASURING AND REGULATING STATION EQUIPMENT	84,969	404	0	0	0	0	0	85,373	95.15
335	DRILLING AND CLEANING EQUIPMENT	49,483	20	0	0	0	0	0	49,503	99.80
337	OTHER EQUIPMENT	11,062	0	0	0	0	0	0	11,062	100.00
TOTAL PRODUCTION PLANT		**1,243,985**	**1,450**	**(23,040)**	**0**	**0**	**0**	**0**	**1,222,395**	**103.32**
STORAGE PLANT										
352.01	WELL CONSTRUCTION	(35,934)	0	0	0	0	0	0	(35,934)	0.00
TOTAL STORAGE PLANT		**(35,934)**	**0**	**0**	**0**	**0**	**0**	**0**	**(35,934)**	**0.00**
TRANSMISSION PLANT										
365.2	RIGHTS-OF-WAY	536,830	11,633	0	0	0	0	0	548,463	63.18
366	STRUCTURES AND IMPROVEMENTS	146,334	1,217	0	0	0	0	0	147,551	90.96
367	MAINS	21,888,205	457,172	332	0	0	0	0	22,345,709	57.19
369	MEASURING AND REGULATING STATION EQUIPMENT	3,965,987	92,285	933	0	0	0	0	4,059,205	65.98
370	COMMUNICATION EQUIPMENT	2,140,531	103,887	0	0	0	0	0	2,244,418	64.38
371	OTHER EQUIPMENT	129,565	1,153	0	0	0	0	0	130,718	92.95
371.1	TESTING EQUIPMENT	152,562	5,061	0	0	0	0	0	157,623	75.05
TOTAL TRANSMISSION PLANT		**28,960,014**	**672,408**	**1,265**	**0**	**0**	**0**	**0**	**29,633,687**	**59.16**
DISTRIBUTION PLANT										
374.2	RIGHTS-OF-WAY	1,380,979	46,079	0	0	0	0	0	1,427,058	40.26
375	STRUCTURES AND IMPROVEMENTS	3,255,821	87,214	(37)	0	0	0	0	3,342,998	60.19
376.1	MAINS - PRIMARILY STEEL	186,259,998	9,833,596	800,099	(214,128)	0	(200,466)	0	196,479,099	30.41
376.2	MAINS - CAST IRON	17,698	351,700	270,813	(364,752)	0	(470,895)	0	(195,436)	-13.40
376.3	MAINS - PLASTIC	290,557,616	26,474,803	531,409	(6,277,530)	0	(1,451,993)	0	309,834,306	17.74
376.5	MAINS - PRIMARILY WROUGHT IRON	243,917	4,628	3,944	(15,273)	0	(19,717)	0	217,498	79.12
376.7	REG AFUDC	398,720	263,757	0	0	0	0	0	662,477	50.11
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	26,618,827	5,102,503	171,751	(2,678,253)	176,836	(531,160)	0	28,860,504	15.24
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	8,409,477	620,950	3,021	0	0	0	0	9,033,448	35.24
380	SERVICES	396,104,279	35,313,974	4,363,954	(7,021,602)	0	(3,623,848)	0	425,136,756	29.27
381	METERS	55,211,410	4,918,081	(3,322)	(1,534,160)	3,702	(1,420)	0	58,594,291	36.39
381.1	METERS - ERTS	19,365,192	605,466	0	0	0	0	0	19,970,658	85.90
382	METER INSTALLATIONS	36,058,830	2,528,852	449,955	(517,857)	0	(267,265)	0	38,252,514	35.26
383	HOUSE REGULATORS	6,698,745	162,090	261,636	(6,349)	0	(3,276)	0	7,112,845	66.32
384	HOUSE REGULATOR INSTALLATIONS	8,896,752	382,468	108,449	(24,046)	0	(12,410)	0	9,351,212	49.34
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	17,515,028	838,713	12,906	0	0	0	0	18,366,647	46.02
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES	(94,200)	9,697	0	0	0	0	0	(84,503)	-122.78
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	663,828	14,775	0	0	0	0	0	678,603	71.19
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,705	0	0	0	0	0	0	24,705	100.00
387	OTHER EQUIPMENT	2,932,388	102,186	0	0	0	0	0	3,034,574	62.30
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,468,898	4,174	0	0	0	0	0	1,473,072	98.82
TOTAL DISTRIBUTION PLANT		**1,061,988,908**	**87,665,703**	**6,974,578**	**(18,653,950)**	**180,538**	**(6,582,451)**	**0**	**1,131,573,326**	**25.48**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2022 PROJECTED TO SEPTEMBER 30, 2023

ACCOUNT (1)	BOOK RESERVE AT BEGINNING OF YEAR (2)	ANNUAL ACCRUAL (3)	AMORTIZATION OF NET SALVAGE (4)	RETIREMENTS (5)	GROSS SALVAGE (6)	COST OF REMOVAL (7)	TRANSFERS AND ADJUSTMENTS (8)	BOOK RESERVE AT END OF YEAR (9)	BOOK RESERVE AS A PERCENT OF ORIGINAL COST (10)
GENERAL PLANT									
390.1 STRUCTURES AND IMPROVEMENTS	42,197,098	3,637,529	32,018	(1,663,190)	0	(166,319)	0	44,037,136	33.37
391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,008,484	300,229	0	(74,005)	0	0	0	1,234,708	24.44
391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	48,200	19,039	0	(1,638)	0	0	0	65,601	34.17
391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	490,975	67,319	0	(575,464)	0	0	0	(17,170)	-19.62
391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	(42,186)	0	0	0	0	0	0	(42,186)	0.00
392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	931,201	562,639	(14,940)	(192,235)	41,215	0	0	1,327,880	29.78
392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	7,238,621	3,499,928	(261,351)	(1,434,641)	307,587	0	0	9,350,145	27.23
392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	998,425	312,430	(19,387)	(140,334)	30,088	0	0	1,181,221	30.13
392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	1,502,377	474,020	(13,752)	(218,793)	46,909	0	0	1,790,761	29.56
392.5 TRANSPORTATION EQUIPMENT - TRAILERS	688,700	185,549	(29,709)	(91,802)	19,682	0	0	772,420	27.91
393 STORES EQUIPMENT	6,326	873	0	0	0	0	0	7,199	40.89
394 TOOLS, SHOP AND GARAGE EQUIPMENT	12,823,468	2,013,158	0	(645,980)	0	0	0	14,190,646	35.30
395 LABORATORY EQUIPMENT	112,149	22,108	0	0	0	0	0	134,257	30.67
396 POWER OPERATED EQUIPMENT	2,417,013	470,882	0	0	0	0	0	2,887,895	43.95
397 COMMUNICATION EQUIPMENT	401,771	108,969	0	(31,838)	0	0	0	478,902	52.80
398 MISCELLANEOUS EQUIPMENT	889,505	215,229	130,569	(48,107)	0	0	0	1,187,196	50.69
TOTAL GENERAL PLANT	**71,712,127**	**11,889,903**	**(176,552)**	**(5,118,027)**	**445,481**	**(166,319)**	**0**	**78,586,613**	**32.84**
TOTAL DEPRECIABLE GAS PLANT	**1,163,869,100**	**100,229,464**	**6,776,251**	**(23,771,977)**	**626,019**	**(6,748,770)**	**0**	**1,240,980,087**	**26.22**
OTHER UTILITY PLANT									
COMMON PLANT									
390.1 STRUCTURES AND IMPROVEMENTS	2,943,559	1,007,592	0	0	0	0	0	3,951,151	11.34
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	0	0	0	0	0	0	0	0	0.00
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	1,014,315	233,034	0	(7,183)	0	0	0	1,240,166	28.44
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	516,102	309,653	0	(88,618)	0	0	0	737,137	54.46
392.1 TRANSPORTATION EQUIPMENT - CARS	71,637	0	0	0	0	0	0	71,637	100.00
398 MISCELLANEOUS EQUIPMENT	3,880	3,211	0	0	0	0	0	7,091	
TOTAL COMMON PLANT	**4,549,493**	**1,553,490**	**0**	**(95,801)**	**0**	**0**	**0**	**6,007,182**	**14.78**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 88.97%	**4,047,684**	**1,382,140**	**0**	**(85,234)**	**0**	**0**	**0**	**5,344,590**	
INFORMATION SERVICES (IS)									
390.1 STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER	0	5200	0	0	0	0	0	5,200	0.13
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	28,532	675	0	(22,684)	0	0	0	6,523	87.45
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	12,323,496	2,767,757	0	(5,584,431)	0	0	0	9,506,822	79.27
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	2,950,328	1,485,656	0	0	0	0	0	4,435,984	32.86
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	10,614,784	5,229,796	0	(381,964)	0	0	0	15,462,616	23.30
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	42,466,804	8,894,759	0	(2,908,998)	0	0	0	48,452,565	36.87
TOTAL INFORMATION SERVICES	**68,383,944**	**18,383,844**	**0**	**(8,898,077)**	**0**	**0**	**0**	**77,869,711**	**34.26**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 91.68%	**62,694,400**	**16,854,308**	**0**	**(8,157,757)**	**0**	**0**	**0**	**71,390,950**	
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS - UNITE ADC	0	1,945,443	0	0	0	0	0	1,945,443	4.72
READING SERVICE CENTER									
390.1 STRUCTURES AND IMPROVEMENTS	1,559,965	0	0	0	0	0	(1,559,965)	0	
LESS READING SERVICE CENTER ALLOCATED TO ELECTRIC DIVISION - 9.31%	**145,233**	**0**	**0**	**0**	**0**	**0**	**(145,233)**	**0**	
EMPIRE YARD BUILDING									
390.1 STRUCTURES AND IMPROVEMENTS	8,165,613	282,869	0	(26,620)	0	0 #	0	8,421,862	58.64
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%	**1,067,246**	**36,971**	**0**	**(3,479)**	**0**	**0**	**0**	**1,100,737**	
TOTAL OTHER UTILITY PLANT ALLOCATED TO ALL GAS DIVISIONS	**65,529,605**	**20,144,920**	**0**	**(8,239,512)**	**0**	**0**	**145,233**	**77,580,246**	
TOTAL DEPRECIABLE PLANT IN SERVICE	**1,229,398,705**	**120,374,384**	**6,776,251**	**(32,011,489)**	**626,019**	**(6,748,770)**	**145,233**	**1,318,560,333**	

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

ACCOUNT (1)		BEGINNING OF YEAR BALANCE (2)	ADDITIONS (3)	RETIREMENTS (4)	TRANSFERS (5)	END OF YEAR BALANCE (6)	ANNUAL ACCRUAL RATE (7)	ANNUAL ACCRUAL AMOUNT* (8)
GAS PLANT								
PRODUCTION PLANT								
305	MANUFACTURED GAS PLANT SITE REMEDIATION	0	0	0	0	0	-	0
325.2	PRODUCING LEASEHOLDS	163,100	0	0	0	163,100	0.02	33
325.4	RIGHTS-OF-WAY	30,277	0	0	0	30,277	0.06	18
328	FIELD MEASURING AND REGULATING STATION STRUCTURES	1,263	0	0	0	1,263	-	0
329	OTHER STRUCTURES	44,785	0	0	0	44,785	-	0
330	PRODUCING GAS WELLS - WELL CONSTRUCTION	18,209	0	0	0	18,209	-	0
331	PRODUCING GAS WELLS - WELL EQUIPMENT	24,441	0	0	0	24,441	-	0
332	FIELD LINES	750,689	0	0	0	750,689	0.13	976
334	FIELD MEASURING AND REGULATING STATION EQUIPMENT	89,725	0	0	0	89,725	0.45	404
335	DRILLING AND CLEANING EQUIPMENT	49,604	0	0	0	49,604	0.04	20
337	OTHER EQUIPMENT	11,062	0	0	0	11,062	-	0
TOTAL PRODUCTION PLANT		**1,183,155**	**0**	**0**	**0**	**1,183,155**		**1,450**
STORAGE PLANT								
352.01	WELL CONSTRUCTION	0	0	0	0	0	-	0
TOTAL STORAGE PLANT		**0**	**0**	**0**	**0**	**0**		**0**
TRANSMISSION PLANT								
365.2	RIGHTS-OF-WAY	868,160	0	0	0	868,160	1.34	11,633
366	STRUCTURES AND IMPROVEMENTS	162,216	0	0	0	162,216	0.75	1,217
367	MAINS	39,074,497	0	0	0	39,074,497	1.17	457,172
369	MEASURING AND REGULATING STATION EQUIPMENT	6,152,338	0	0	0	6,152,338	1.50	92,285
370	COMMUNICATION EQUIPMENT	3,486,136	0	0	0	3,486,136	2.98	103,887
371	OTHER EQUIPMENT	140,637	0	0	0	140,637	0.82	1,153
371.1	TESTING EQUIPMENT	210,011	0	0	0	210,011	2.41	5,061
TOTAL TRANSMISSION PLANT		**50,093,995**	**0**	**0**	**0**	**50,093,995**		**672,408**
DISTRIBUTION PLANT								
374.2	RIGHTS-OF-WAY	3,544,569	0	0	0	3,544,569	1.30	46,079
375	STRUCTURES AND IMPROVEMENTS	5,554,376	0	0	0	5,554,376	1.57	87,214
376.1	MAINS - PRIMARILY STEEL	642,022,976	4,204,699	(214,128)	0	646,013,547	1.53	9,833,596
376.2	MAINS - CAST IRON	1,823,760	0	(364,752)	0	1,459,008	21.43	351,700
376.3	MAINS - PLASTIC	1,502,936,181	249,692,680	(6,277,530)	0	1,746,351,331	1.65	26,474,803
376.5	MAINS - PRIMARILY WROUGHT IRON	290,185	0	(15,273)	0	274,912	1.64	4,628
376.7	REG AFUDC	1,322,088	0	0	0	1,322,088	19.95	263,757
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	157,824,797	34,216,384	(2,678,253)	0	189,362,928	2.99	5,102,503
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	25,635,909	0	0	0	25,635,909	2.42	620,950
380	SERVICES	1,386,388,924	73,000,786	(7,021,602)	0	1,452,368,108	2.50	35,313,974
381	METERS	152,689,621	9,876,477	(1,534,160)	0	161,031,938	3.15	4,918,081
381.1	METERS - ERTS	23,249,326	0	0	0	23,249,326	2.61	605,466
382	METER INSTALLATIONS	103,616,708	5,383,942	(517,857)	0	108,482,793	2.39	2,528,852
383	HOUSE REGULATORS	10,665,811	66,000	(6,349)	0	10,725,462	1.52	162,090
384	HOUSE REGULATOR INSTALLATIONS	18,727,622	250,000	(24,046)	0	18,953,576	2.03	382,468
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	39,907,546	0	0	0	39,907,546	2.10	838,713
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES	68,824	0	0	0	68,824	14.09	9,697
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	953,218	0	0	0	953,218	1.55	14,775
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,705	0	0	0	24,705	-	0
387	OTHER EQUIPMENT	4,871,243	0	0	0	4,871,243	2.10	102,186
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,490,664	0	0	0	1,490,664	0.28	4,174
TOTAL DISTRIBUTION PLANT		**4,083,609,053**	**376,690,968**	**(18,653,950)**	**0**	**4,441,646,071**		**87,665,703**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

ACCOUNT	BEGINNING OF YEAR BALANCE	ADDITIONS	RETIREMENTS	TRANSFERS	END OF YEAR BALANCE	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT*
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
GENERAL PLANT							
390.1 STRUCTURES AND IMPROVEMENTS	112,227,655	21,413,196	(1,663,190)	0	131,977,661	4.17	3,637,529
391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	4,776,937	350,000	(74,005)	0	5,052,932	6.16	300,229
391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	193,634	0	(1,638)	0	191,996	9.88	19,039
391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	662,977	0	(575,464)	0	87,513	18.92	67,319
391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	-	0	0	0	0	-	0
392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	3,614,867	1,036,745	(192,235)	0	4,459,377	14.20	562,639
392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	28,028,978	7,737,196	(1,434,641)	0	34,331,533	11.45	3,499,928
392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	3,304,380	756,839	(140,334)	0	3,920,885	8.77	312,430
392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	5,097,822	1,179,972	(218,793)	0	6,059,001	8.65	474,020
392.5 TRANSPORTATION EQUIPMENT - TRAILERS	2,364,560	495,098	(91,802)	0	2,767,856	7.35	185,549
393 STORES EQUIPMENT	17,606	0	0	0	17,606	4.96	873
394 TOOLS, SHOP AND GARAGE EQUIPMENT	37,478,859	3,366,727	(645,980)	0	40,199,606	5.24	2,013,158
395 LABORATORY EQUIPMENT	437,779	0	0	0	437,779	5.05	22,108
396 POWER OPERATED EQUIPMENT	6,570,611	0	0	0	6,570,611	7.17	470,882
397 COMMUNICATION EQUIPMENT	938,798	0	(31,838)	0	906,960	11.83	108,969
398 MISCELLANEOUS EQUIPMENT	2,390,378	2	(48,107)	0	2,342,273	9.08	215,229
TOTAL GENERAL PLANT	**208,105,841**	**36,335,775**	**(5,118,027)**	**0**	**239,323,589**		**11,889,902**
TOTAL DEPRECIABLE GAS PLANT	**4,342,992,044**	**413,026,743**	**(23,771,977)**	**0**	**4,732,246,810**		**100,229,464**
NONDEPRECIABLE PLANT							
301 ORGANIZATION	166,478	0	0	0	166,478		
302 FRANCHISES AND CONSENTS	193,597	0	0	0	193,597		
303 MISCELLANEOUS INTANGIBLE PLANT	289,868	0	0	0	289,868		
304.1 LAND AND LAND RIGHTS - LAND	375,198	0	0	0	375,198		
304.2 LAND AND LAND RIGHTS - LAND RIGHTS	6,454	0	0	0	6,454		
325.1 PRODUCING LANDS	13,029	0	0	0	13,029		
325.5 OTHER LAND	1,134	0	0	0	1,134		
365.1 LAND	47,323	0	0	0	47,323		
374.1 LAND AND LAND RIGHTS - LAND	849,347	0	0	0	849,347		
374.2 LAND AND LAND RIGHTS - LAND RIGHTS	7,305,824	0	0	0	7,305,824		
389.1 LAND AND LAND RIGHTS - LAND	10,369,472	0	0	0	10,369,472		
389.2 LAND AND LAND RIGHTS - LAND RIGHTS	1,313	0	0	0	1,313		
TOTAL NONDEPRECIABLE PLANT	**19,619,037**	**0**	**0**	**0**	**19,619,037**		
TOTAL GAS PLANT	**4,362,611,081**	**413,026,743**	**(23,771,977)**	**0**	**4,751,865,847**		

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023

ACCOUNT (1)	BEGINNING OF YEAR BALANCE (2)	ADDITIONS (3)	RETIREMENTS (4)	TRANSFERS (5)	END OF YEAR BALANCE (6)	ANNUAL ACCRUAL RATE (7)	ANNUAL ACCRUAL AMOUNT* (8)
OTHER UTILITY PLANT							
COMMON PLANT							
301 ORGANIZATION (NONDEPRECIABLE)	138,964	0	0	0	138,964		
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	6,947,108	0	0	0	6,947,108		
390.1 STRUCTURES AND IMPROVEMENTS	34,740,353	100,454	0	0	34,840,807	2.90	1,007,592
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	0	0	0	0	0	-	0
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	4,367,824	0	(7,183)	0	4,360,642	5.34	233,034
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	1,442,208	0	(88,618)	0	1,353,590	22.21	309,653
392.1 TRANSPORTATION EQUIPMENT - CARS	71,637	0	0	0	71,637	-	0
398 MISCELLANEOUS EQUIPMENT	27,967	0	0	0	27,967	11.48	3,211
TOTAL COMMON PLANT	**47,736,061**	**100,454**	**(95,801)**	**0**	**47,740,715**		**1,553,490**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 88.97%	**42,470,774**	**89,374**	**(85,234)**	**0**	**42,474,914**		**1,382,140**
INFORMATION SERVICES (IS)							
390.1 STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER	0	4,000,001	0	0	4,000,001	**	5,200
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	30,143	0	(22,684)	0	7,459	3.78	675
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	17,576,725	0	(5,584,431)	0	11,992,294	19.02	2,767,757
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	13,499,682	0	0	0	13,499,682	10.24	1,485,656
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	46,573,593	20,180,262	(381,964)	0	66,371,890	10.32	5,229,796
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	134,333,306	0	(2,908,998)	0	131,424,308	6.70	8,894,759
TOTAL INFORMATION SERVICES	**212,013,449**	**24,180,263**	**(8,898,077)**	**0**	**227,295,634**		**18,383,844**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 91.68%	**194,373,930**	**22,168,465**	**(8,157,757)**	**0**	**208,384,637**		**16,854,308**
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS - UNITE ADC	0	41,177,032	0	0	41,177,032	6.67	1,945,443
READING SERVICE CENTER							
390.1 STRUCTURES AND IMPROVEMENTS	2,213,194	0	0	(2,213,194)	0		0
LESS READING SERVICE CENTER ALLOCATED TO ELECTRIC DIVISION - 9.31%	**206,048**	**0**	**0**	**(206,048)**	**0**		**0**
EMPIRE YARD BUILDING							
390.1 STRUCTURES AND IMPROVEMENTS	14,122,387	266,204	(26,620)	0	14,361,971	1.97	282,869
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%	**1,845,796**	**34,793**	**(3,479)**	**0**	**1,877,110**		**36,971**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ALL GAS DIVISIONS	**234,792,860**	**63,400,078**	**(8,239,512)**	**206,048**	**290,159,473**		**20,144,920**
TOTAL PLANT IN SERVICE	**4,597,403,941**	**476,426,821**	**(32,011,489)**	**206,048**	**5,042,025,320**		**120,374,384**

* TOTAL ACCRUALS SHOWN ARE BASED ON AVERAGE MONTHLY BALANCES.
**NEW DATA CENTER TO RECEIVE HALF A MONTH OF ACCRUALS.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

	2019		2020		2021		2022		2023		FIVE YEAR	NET
ACCOUNT	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	NET SALVAGE TOTAL	SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GAS PLANT												
PRODUCTION PLANT												
305	0	0	0	0	(115,195)	0	0	0	0	0	(115,195)	(23,039)
325.2	0	0	0	0	0	0	0	0	0	0	0	0
325.4	0	0	0	0	0	0	0	0	0	0	0	0
328	0	0	0	0	0	0	0	0	0	0	0	0
329	0	0	0	0	0	0	0	0	0	0	0	0
330	0	0	0	0	0	0	0	0	0	0	0	0
331	0	0	0	0	0	0	0	0	0	0	0	0
332	0	0	0	0	0	0	0	0	0	0	0	0
334	0	0	0	0	0	0	0	0	0	0	0	0
335	0	0	0	0	0	0	0	0	0	0	0	0
337	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**(115,195)**	**0**	**0**	**0**	**0**	**0**	**(115,195)**	**(23,039)**
STORAGE PLANT												
352.01	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TRANSMISSION PLANT												
365.2	0	0	0	0	0	0	0	0	0	0	0	0
366	0	0	0	0	0	0	0	0	0	0	0	0
367	0	0	0	0	0	1,660	0	0	0	0	1,660	332
369	0	131	0	0	0	3,386	0	0	0	0	3,517	703
370	0	0	0	0	0	0	0	0	0	0	0	0
371	0	0	0	0	0	0	0	0	0	0	0	0
371.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**131**	**0**	**0**	**0**	**5,046**	**0**	**0**	**0**	**0**	**5,177**	**1,035**
DISTRIBUTION PLANT												
374.2	0	0	0	0	0	0	0	0	0	0	0	0
375	0	0	0	0	0	0	0	0	0	0	0	0
376.1	(23,558)	527,144	0	422,998	0	1,712,927	0	244,266	0	200,466	3,084,243	616,849
376.2	0	(284,507)	0	529,595	0	92,247	0	470,895	0	470,895	1,279,125	255,825
376.3	0	197,897	0	77,475	0	728,986	0	1,287,209	0	1,451,993	3,743,560	748,711
376.5	0	0	0	0	0	0	0	19,717	0	19,717	39,434	7,887
378	(54,593)	154,135	0	29,723	0	168,692	(218,659)	656,781	(176,836)	531,160	1,090,403	218,081
379	0	0	0	0	0	15,105	0	0	0	0	15,105	3,021
380	0	3,425,191	0	4,911,297	0	4,191,361	0	3,574,917	0	3,623,848	19,726,614	3,945,323
381	0	770	0	0	(19,201)	1,237	(4,145)	1,589	(3,702)	1,420	(22,032)	(4,406)
381.1	0	0	0	0	0	0	0	0	0	0	0	0
382	0	262,633	0	1,144,545	0	224,823	0	289,694	0	267,265	2,188,960	437,792
383	0	(54,424)	0	2,130	0	269	0	3,276	0	3,276	(45,473)	(9,095)
384	0	(2)	0	515,427	0	13,720	0	12,410	0	12,410	553,965	110,793
385	0	4,047	0	0	0	35,290	0	0	0	0	39,337	7,867
386.0	0	0	0	0	0	0	0	0	0	0	0	0
386.1	0	0	0	0	0	0	0	0	0	0	0	0
386.2	0	0	0	0	0	0	0	0	0	0	0	0
387	0	0	0	0	0	0	0	0	0	0	0	0
387.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**(78,151)**	**4,232,884**	**0**	**7,633,190**	**(19,201)**	**7,184,657**	**(222,804)**	**6,560,754**	**(180,538)**	**6,582,451**	**31,693,242**	**6,338,648**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

ACCOUNT	2019 GROSS SALVAGE	2019 COST OF REMOVAL	2020 GROSS SALVAGE	2020 COST OF REMOVAL	2021 GROSS SALVAGE	2021 COST OF REMOVAL	2022 GROSS SALVAGE	2022 COST OF REMOVAL	2023 GROSS SALVAGE	2023 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GENERAL PLANT												
390.1	0	76,973	0	17,949	0	135	0	65,735	0	166,319	327,111	65,422
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	(30,492)	0	0	0	(44,216)	0	(41,215)	0	(115,923)	(23,185)
392.2	0	0	(449,978)	0	(526,894)	0	(329,980)	0	(307,587)	0	(1,614,439)	(322,887)
392.3	0	0	(64,698)	0	0	0	(32,278)	0	(30,088)	0	(127,064)	(25,412)
392.4	0	0	(18,471)	0	0	0	(50,324)	0	(46,909)	0	(115,704)	(23,140)
392.5	0	0	(127,432)	0	0	0	(21,116)	0	(19,682)	0	(168,230)	(33,646)
393	0	0	0	0	0	0	0	0	0	0	0	0
394	0	0	0	0	0	0	0	0	0	0	0	0
395	0	0	0	0	0	0	0	0	0	0	0	0
396	0	0	0	0	0	0	0	0	0	0	0	0
397	0	0	0	0	0	0	0	0	0	0	0	0
398	0	652	0	257,300	0	391,820	0	0	0	0	649,772	129,954
TOTAL	**0**	**77,625**	**(691,071)**	**275,249**	**(526,894)**	**391,955**	**(477,914)**	**65,735**	**(445,481)**	**166,319**	**(1,164,477)**	**(232,894)**
TOTAL GAS PLANT	**(78,151)**	**4,310,640**	**(691,071)**	**7,908,439**	**(661,290)**	**7,581,658**	**(700,718)**	**6,626,489**	**(626,019)**	**6,748,770**	**30,418,747**	**6,083,750**
OTHER UTILITY PLANT												
COMMON PLANT												
390.1	0	0	0	0	0	0	0	0	0	0	0	0
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
INFORMATION SERVICES												
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
GRAND TOTAL	**(78,151)**	**4,310,640**	**(691,071)**	**7,908,439**	**(661,290)**	**7,581,658**	**(700,718)**	**6,626,489**	**(626,019)**	**6,748,770**	**30,418,747**	**6,083,750**

* COLUMN (12) EQUALS THE SUMMATION OF COLUMNS (2) THROUGH (11).

PART III. DETAILED DEPRECIATION CALCULATIONS

CUMULATIVE DEPRECIATED ORIGINAL COST

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1849	2,795	2,795			0.0
1862	16	16			0.0
1867	72	72			0.0
1871	2,385	2,385			0.0
1879	351	351			0.0
1880	110	110			0.0
1881	275	275			0.0
1882	48	48			0.0
1883	45	45			0.0
1885	2	2			0.0
1887	40	36	4	4	0.0
1888	4,362	4,344	18	22	0.0
1889	23	20	3	25	0.0
1890	146	129	17	42	0.0
1891	6	6		42	0.0
1892	1,496	1,496		42	0.0
1893	179	157	22	64	0.0
1894	2,652	2,652		64	0.0
1895	69	62	7	71	0.0
1896	164	140	24	95	0.0
1897	3,928	3,919	9	104	0.0
1898	20,735	20,707	28	132	0.0
1899	9,201	9,056	145	277	0.0
1901	79,950	79,419	531	808	0.0
1902	16,826	16,707	119	927	0.0
1903	47,953	47,495	458	1,385	0.0
1904	68,237	66,889	1,348	2,733	0.0
1905	53,303	52,683	620	3,353	0.0
1906	14,532	13,154	1,378	4,731	0.0
1907	27,278	25,387	1,891	6,622	0.0
1908	44,541	40,537	4,004	10,626	0.0
1909	19,377	18,223	1,154	11,780	0.0
1910	19,965	17,216	2,749	14,529	0.0
1911	32,929	29,232	3,697	18,226	0.0
1912	22,544	19,381	3,163	21,389	0.0
1913	62,207	58,287	3,920	25,309	0.0
1914	59,844	50,109	9,735	35,044	0.0
1915	36,263	30,206	6,057	41,101	0.0
1916	28,337	24,542	3,795	44,896	0.0
1917	19,980	19,188	792	45,688	0.0
1918	13,616	12,589	1,027	46,715	0.0
1919	26,144	24,601	1,543	48,258	0.0
1920	39,172	37,351	1,821	50,079	0.0
1921	86,715	77,722	8,993	59,072	0.0
1922	70,483	62,924	7,559	66,631	0.0
1923	91,846	81,423	10,423	77,054	0.0

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST: AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1924	330,310	302,618	27,692	104,746	0.0
1925	134,395	115,046	19,349	124,095	0.0
1926	408,976	353,534	55,442	179,537	0.0
1927	208,698	173,813	34,885	214,422	0.0
1928	294,497	258,373	36,124	250,546	0.0
1929	218,562	161,119	57,443	307,989	0.0
1930	529,123	456,736	72,387	380,376	0.0
1931	463,449	397,275	66,174	446,550	0.0
1932	139,065	129,816	9,249	455,799	0.0
1933	165,318	161,514	3,804	459,603	0.0
1934	44,424	41,281	3,143	462,746	0.0
1935	50,860	44,883	5,977	468,723	0.0
1936	54,114	42,206	11,908	480,631	0.0
1937	56,687	50,868	5,819	486,450	0.0
1938	39,451	34,459	4,992	491,442	0.0
1939	65,615	50,057	15,558	507,000	0.0
1940	90,108	76,744	13,364	520,364	0.0
1941	174,374	149,929	24,445	544,809	0.0
1942	78,918	72,813	6,105	550,914	0.0
1943	30,550	27,794	2,756	553,670	0.0
1944	44,994	39,683	5,311	558,981	0.0
1945	48,950	45,977	2,973	561,954	0.0
1946	523,733	435,764	87,969	649,923	0.0
1947	189,132	153,716	35,416	685,339	0.0
1948	271,096	210,027	61,069	746,408	0.0
1949	653,548	577,913	75,635	822,043	0.0
1950	2,278,609	1,880,224	398,385	1,220,428	0.0
1951	687,230	546,995	140,235	1,360,663	0.0
1952	1,766,349	1,417,896	348,453	1,709,116	0.0
1953	1,536,688	1,133,921	402,767	2,111,883	0.1
1954	2,166,738	1,762,607	404,131	2,516,014	0.1
1955	3,193,008	2,665,612	527,396	3,043,410	0.1
1956	2,961,709	2,223,007	738,702	3,782,112	0.1
1957	5,250,920	4,082,542	1,168,378	4,950,490	0.1
1958	4,034,504	3,077,292	957,212	5,907,702	0.2
1959	3,989,794	2,936,955	1,052,839	6,960,541	0.2
1960	5,160,095	3,966,981	1,193,114	8,153,655	0.2
1961	5,357,502	4,126,047	1,231,455	9,385,110	0.3
1962	4,326,903	3,203,928	1,122,975	10,508,085	0.3
1963	6,000,752	4,354,911	1,645,841	12,153,926	0.3
1964	7,364,141	5,211,440	2,152,701	14,306,627	0.4
1965	8,212,541	5,890,492	2,322,049	16,628,676	0.5
1966	8,913,539	6,456,499	2,457,040	19,085,716	0.5
1967	9,130,425	6,574,754	2,555,671	21,641,387	0.6
1968	10,807,217	7,523,216	3,284,001	24,925,388	0.7
1969	11,334,984	7,833,337	3,501,647	28,427,035	0.8

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1970	10,374,252	7,211,684	3,162,568	31,589,603	0.9
1971	9,699,671	6,666,495	3,033,176	34,622,779	1.0
1972	10,721,054	7,118,975	3,602,079	38,224,858	1.1
1973	9,788,142	6,698,091	3,090,051	41,314,909	1.2
1974	10,325,680	7,240,547	3,085,133	44,400,042	1.3
1975	8,739,717	5,914,207	2,825,510	47,225,552	1.4
1976	8,350,808	5,609,935	2,740,873	49,966,425	1.4
1977	10,592,165	6,933,797	3,658,368	53,624,793	1.5
1978	10,043,791	6,413,127	3,630,664	57,255,457	1.6
1979	15,131,143	9,506,046	5,625,097	62,880,554	1.8
1980	26,984,160	16,993,623	9,990,537	72,871,091	2.1
1981	26,620,008	16,379,826	10,240,182	83,111,273	2.4
1982	26,427,104	17,343,012	9,084,092	92,195,365	2.6
1983	13,947,244	9,399,568	4,547,676	96,743,041	2.8
1984	18,320,469	12,025,478	6,294,991	103,038,032	3.0
1985	22,340,125	14,637,610	7,702,515	110,740,547	3.2
1986	26,921,148	17,149,757	9,771,391	120,511,938	3.5
1987	30,691,573	19,411,756	11,279,817	131,791,755	3.8
1988	41,148,580	24,957,347	16,191,233	147,982,988	4.2
1989	46,046,238	27,838,935	18,207,303	166,190,291	4.8
1990	48,798,365	29,060,160	19,738,205	185,928,496	5.3
1991	37,946,412	22,430,550	15,515,862	201,444,358	5.8
1992	43,928,060	26,079,714	17,848,346	219,292,704	6.3
1993	32,628,969	18,951,701	13,677,268	232,969,972	6.7
1994	49,844,340	28,691,374	21,152,966	254,122,938	7.3
1995	58,830,863	31,049,701	27,781,162	281,904,100	8.1
1996	61,839,855	31,186,710	30,653,145	312,557,245	9.0
1997	73,506,719	36,458,692	37,048,027	349,605,272	10.0
1998	59,726,221	29,323,014	30,403,207	380,008,479	10.9
1999	47,203,751	22,984,485	24,219,266	404,227,745	11.6
2000	60,626,618	27,575,649	33,050,969	437,278,714	12.5
2001	60,927,778	27,852,414	33,075,364	470,354,078	13.5
2002	57,240,535	25,977,340	31,263,195	501,617,273	14.4
2003	57,143,799	24,038,226	33,105,573	534,722,846	15.3
2004	76,399,707	33,395,642	43,004,065	577,726,911	16.5
2005	67,946,792	27,287,830	40,658,962	618,385,873	17.7
2006	65,015,019	27,475,728	37,539,291	655,925,164	18.8
2007	64,852,520	24,581,120	40,271,400	696,196,564	19.9
2008	68,523,293	24,212,297	44,310,996	740,507,560	21.2
2009	65,532,120	21,283,691	44,248,429	784,755,989	22.5
2010	60,616,312	19,012,992	41,603,320	826,359,309	23.7
2011	86,187,348	24,737,670	61,449,678	887,808,987	25.4
2012	104,208,957	27,327,687	76,881,270	964,690,257	27.6
2013	123,764,511	29,504,672	94,259,839	1,058,950,096	30.3
2014	156,890,463	33,503,604	123,386,859	1,182,336,955	33.9
2015	182,587,478	35,087,940	147,499,538	1,329,836,493	38.1

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2016	203,524,067	34,629,176	168,894,891	1,498,731,384	42.9
2017	204,267,172	30,234,494	174,032,678	1,672,764,062	47.9
2018	295,921,218	37,351,461	258,569,757	1,931,333,819	55.3
2019	273,425,701	31,485,348	241,940,353	2,173,274,172	62.2
2020	278,915,325	28,654,697	250,260,628	2,423,534,800	69.4
2021	314,218,122	21,191,303	293,026,819	2,716,561,619	77.8
2022	382,296,954	15,187,257	367,109,697	3,083,671,316	88.3
2023	412,934,634	5,370,020	407,564,614	3,491,235,930	100.0
TOTAL	4,732,246,807	1,241,010,877	3,491,235,930		

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

				DEPRECIATED ORIGINAL COST	
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2004	38,772	37,470	1,302	1,302	0.0
2005	39,966	33,765	6,201	7,503	0.0
2006	2,469	1,973	496	7,999	0.0
2007	878	661	217	8,216	0.0
2008	23,109	22,942	167	8,383	0.0
2009	4,753	3,147	1,606	9,989	0.0
2010	747,319	460,740	286,579	296,568	0.9
2014	22,225	22,225		296,568	0.9
2019	33,840,603	4,570,730	29,269,873	29,566,441	85.3
2020	1,962,770	197,765	1,765,005	31,331,446	90.4
2021	1,747,559	553,123	1,194,436	32,525,882	93.9
2022	2,123,767	100,795	2,022,972	34,548,854	99.7
2023	100,454	1,845	98,609	34,647,463	100.0
TOTAL	40,654,644	6,007,181	34,647,463		

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2004	5,699	5,171	528	528	0.0
2007	1,760	1,352	408	936	0.0
2011	425,873	348,918	76,955	77,891	0.0
2012	401,290	302,477	98,813	176,704	0.1
2013	142,365	97,977	44,388	221,092	0.1
2014	1,484,161	1,183,379	300,782	521,874	0.3
2015	732,103	579,641	152,462	674,336	0.4
2016	2,349,695	1,347,686	1,002,009	1,676,345	0.9
2017	77,621,819	33,311,799	44,310,020	45,986,365	24.4
2018	1,556,496	771,307	785,189	46,771,554	24.8
2019	74,206,213	28,448,722	45,757,491	92,529,045	49.0
2020	15,090,976	5,567,083	9,523,893	102,052,938	54.1
2021	14,002,023	2,927,915	11,074,108	113,127,046	60.0
2022	15,094,900	2,031,218	13,063,682	126,190,728	66.9
2023	65,357,295	2,890,508	62,466,787	188,657,515	100.0
TOTAL	268,472,668	79,815,153	188,657,515		

UTILITY PLANT IN SERVICE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.2 PRODUCING LEASEHOLDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 55-S0.5						
NET SALVAGE PERCENT.. 0						
1892	1,496.50	1,496	1,497			
1894	2,650.57	2,651	2,651			
1897	3,621.53	3,622	3,622			
1898	13,387.22	13,387	13,387			
1899	1,044.85	1,045	1,045			
1901	748.25	748	748			
1902	4,491.26	4,491	4,491			
1904	8,221.11	8,221	8,221			
1905	43,088.40	43,088	43,088			
1906	1,680.87	1,681	1,681			
1907	471.47	471	471			
1908	75.00	75	75			
1909	1,941.30	1,941	1,941			
1911	526.00	526	526			
1912	2,693.57	2,694	2,694			
1913	31,916.65	31,917	31,917			
1914	1,141.85	1,137	1,142			
1917	1,200.00	1,173	1,200			
1918	701.79	681	702			
1919	1,973.32	1,903	1,973			
1921	2,993.63	2,850	2,994			
1923	1.00	1	1			
1926	4,047.55	3,729	4,048			
1928	1,435.71	1,305	1,436			
1929	962.33	869	962			
1935	951.47	824	951			
1937	52.56	45	53			
1939	15.58	13	16			
1940	13.75	11	14			
1941	15,225.35	12,629	15,225			
1944	2,221.48	1,801	2,221			
1945	161.26	130	161			
1946	629.70	502	630			
1948	1.00	1	1			
1950	181.23	140	181			
1954	35.07	26	35			
1956	7.72	6	8			
1959	142.79	101	143			
1960	131.99	93	132			
1962	47.49	33	47			
1963	10.00	7	10			
1972	6,120.00	3,753	6,120			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.2 PRODUCING LEASEHOLDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 55-S0.5						
NET SALVAGE PERCENT.. 0						
1973	7.08	4	7			
1990	260.71	149	255	5	24.98	
1998	3,274.34	1,561	2,676	599	27.98	21
2004	1,098.03	430	737	361	30.25	12
	163,100.33	153,961	162,135	965		33

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.2 0.02

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.4 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. 0						
1898	11.00	11	11			
1899	76.80	77	77			
1903	286.00	286	286			
1905	534.24	528	534			
1906	439.95	432	440			
1907	1,303.60	1,274	1,304			
1908	371.67	361	372			
1909	542.65	524	543			
1910	24.50	24	25			
1912	1.00	1	1			
1913	308.44	291	308			
1914	406.05	381	406			
1915	104.20	97	104			
1916	83.46	78	83			
1917	271.07	250	271			
1918	13.60	12	14			
1919	364.18	333	364			
1920	372.95	339	373			
1921	422.37	382	422			
1922	3.00	3	3			
1923	214.30	192	214			
1924	233.93	208	234			
1925	186.30	165	186			
1926	648.74	570	649			
1927	81.77	71	82			
1928	1,265.69	1,098	1,266			
1929	342.53	295	343			
1930	105.29	90	105			
1931	153.25	131	153			
1932	259.70	220	260			
1933	11.55	10	12			
1934	99.17	83	99			
1935	711.79	590	712			
1936	219.39	181	219			
1937	178.48	146	178			
1938	16.54	13	17			
1939	97.49	78	97			
1940	1,167.50	933	1,168			
1941	4,651.28	3,688	4,651			
1942	570.16	449	570			
1943	210.83	165	211			
1944	372.59	288	373			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.4 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. 0						
1945	869.26	667	869			
1946	288.26	219	288			
1947	1,980.20	1,494	1,980			
1948	494.28	369	494			
1949	1,215.91	901	1,216			
1950	409.99	301	410			
1951	8.42	6	8			
1952	174.36	126	174			
1953	33.53	24	34			
1954	319.31	225	319			
1955	18.46	13	18			
1956	100.07	69	100			
1957	5.20	4	5			
1958	125.16	85	125			
1959	78.61	53	79			
1960	140.63	93	141			
1961	48.55	32	49			
1962	238.74	154	239			
1963	73.00	46	73			
1964	30.64	19	30			
1965	327.04	203	325	2	22.77	
1966	1,949.99	1,194	1,913	37	23.27	2
1967	210.02	127	203	7	23.77	
1968	601.24	358	574	28	24.28	1
1969	260.06	153	245	15	24.79	1
1970	30.26	17	27	3	25.32	
1971	494.97	282	452	43	25.84	2
1972	59.23	33	53	6	26.37	
1973	350.14	193	309	41	26.91	2
1974	44.07	24	38	6	27.46	
1975	183.82	98	157	27	28.01	1
1976	51.01	27	43	8	28.56	
1977	10.01	5	8	2	29.12	
1983	289.96	173	277	13	27.52	
1992	292.64	147	236	57	31.40	2
1999	643.99	268	429	215	34.32	6
2011	87.04	22	35	52	37.50	1
	30,277.07	23,572	29,717	560		18

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.1 0.06

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 328 FIELD MEASURING AND REGULATING STATION STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1932	154.10	154	154			
1946	22.99	23	23			
1954	330.80	331	331			
1962	466.92	467	467			
1963	288.39	288	288			
	1,263.20	1,263	1,263			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 329 OTHER STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1926	189.95	190	190			
1928	18,125.42	18,125	18,125			
1931	33.50	34	34			
1933	286.63	287	287			
1949	75.00	75	75			
1954	1,624.46	1,624	1,624			
1956	1,968.24	1,968	1,968			
1957	165.09	165	165			
1958	4,854.42	4,854	4,854			
1959	592.97	593	593			
1960	6,765.22	6,765	6,765			
1961	3,361.70	3,362	3,362			
1962	1,509.75	1,510	1,510			
1965	132.84	133	133			
1968	78.04	78	78			
1980	5,021.43	5,021	5,020	2		
	44,784.66	44,784	44,783	2		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 330 PRODUCING GAS WELLS - WELL CONSTRUCTION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1924	704.67	705	705			
1927	1,923.69	1,924	1,924			
1931	1,001.26	1,001	1,001			
1934	627.61	628	628			
1936	108.46	108	108			
1940	17.42	17	17			
1942	3,414.11	3,414	3,414			
1943	779.98	780	780			
1945	470.98	471	471			
1946	6,271.05	6,271	6,271			
1947	904.72	905	905			
1948	274.43	274	274			
1955	331.39	331	331			
1972	894.00	894	894			
2004	484.83	485	485			
	18,208.60	18,208	18,209			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 331 PRODUCING GAS WELLS - WELL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1901	115.50	116	116			
1902	202.95	203	203			
1905	127.93	128	128			
1906	12.45	12	12			
1907	1,080.85	1,081	1,081			
1908	1,477.83	1,478	1,478			
1909	298.52	299	299			
1910	158.72	159	159			
1911	277.88	278	278			
1912	291.82	292	292			
1913	214.87	215	215			
1915	441.31	441	441			
1916	189.45	189	189			
1920	640.55	641	641			
1924	501.79	502	502			
1927	432.64	433	433			
1928	569.18	569	569			
1931	299.31	299	299			
1939	388.95	389	389			
1940	380.36	380	380			
1942	672.69	673	673			
1943	957.14	957	957			
1944	255.87	256	256			
1946	812.99	813	813			
1947	296.62	297	297			
1951	235.61	236	236			
1955	200.97	201	201			
1962	296.02	296	296			
1964	413.45	413	413			
1965	1,320.34	1,320	1,320			
1972	10,716.00	10,716	10,716			
1981	66.91	67	67			
1987	93.25	93	94			
	24,440.72	24,442	24,441			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 47-L0						
NET SALVAGE PERCENT.. 0						
1895	16.96	13	17			
1898	6,981.14	5,439	6,981			
1899	7,115.14	5,519	7,115			
1901	2,982.56	2,294	2,983			
1902	9,652.93	7,394	9,653			
1903	13,659.72	10,416	13,660			
1904	14,815.75	11,247	14,816			
1905	1,275.77	964	1,276			
1906	513.25	386	513			
1907	6,359.95	4,763	6,360			
1908	3,151.76	2,349	3,152			
1909	2,862.37	2,124	2,862			
1910	307.46	227	307			
1911	2,431.84	1,787	2,432			
1912	2,319.31	1,696	2,319			
1913	5,593.31	4,070	5,593			
1914	6,309.19	4,567	6,309			
1915	4,636.59	3,339	4,637			
1916	6,215.03	4,454	6,215			
1917	4,867.38	3,470	4,867			
1918	88.42	63	88			
1919	3,165.58	2,233	3,166			
1920	11,810.32	8,287	11,810			
1921	1,551.67	1,083	1,552			
1922	4,953.14	3,437	4,953			
1923	1,197.31	826	1,197			
1924	26,520.98	18,198	26,521			
1925	3,581.94	2,443	3,582			
1926	846.23	574	846			
1927	8,969.93	6,048	8,970			
1928	500.19	335	500			
1929	1,246.96	831	1,247			
1930	822.22	544	822			
1931	5,959.34	3,920	5,959			
1932	284.85	186	285			
1933	295.44	192	295			
1934	1,434.24	926	1,434			
1935	734.99	471	735			
1936	655.62	418	656			
1937	590.14	373	590			
1938	1,716.44	1,078	1,716			
1939	6,274.96	3,913	6,275			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 47-L0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1940	20,933.33	12,961	20,933			
1941	54,988.08	33,800	54,988			
1942	8,386.40	5,117	8,386			
1943	3,472.45	2,103	3,472			
1944	5,918.84	3,558	5,919			
1945	5,041.98	3,007	5,042			
1946	8,811.89	5,214	8,812			
1947	10,683.12	6,269	10,683			
1948	2,599.34	1,513	2,599			
1949	50,912.72	29,388	50,913			
1950	7,587.88	4,344	7,588			
1951	1,414.44	803	1,414			
1952	2,347.14	1,320	2,347			
1953	485.25	271	485			
1954	7,899.95	4,365	7,900			
1955	7,421.47	4,063	7,421			
1956	7,758.34	4,208	7,758			
1957	11,247.12	6,042	11,247			
1958	19,011.79	10,113	19,012			
1959	5,911.91	3,114	5,912			
1960	9,496.60	4,952	9,475	21	22.49	1
1961	6,128.13	3,162	6,050	78	22.75	3
1962	12,642.83	6,456	12,353	290	23.00	13
1963	10,595.86	5,352	10,240	355	23.26	15
1964	15,728.29	7,857	15,034	695	23.52	30
1965	23,533.62	11,627	22,247	1,287	23.78	54
1966	12,682.25	6,193	11,850	833	24.05	35
1967	21,327.23	10,296	19,700	1,627	24.31	67
1968	24,415.86	11,642	22,276	2,140	24.59	87
1969	23,449.66	11,046	21,135	2,314	24.86	93
1970	9,454.39	4,399	8,417	1,037	25.13	41
1971	20,918.97	9,609	18,386	2,533	25.41	100
1972	26,190.05	11,875	22,722	3,469	25.69	135
1973	25,358.45	11,341	21,700	3,659	25.98	141
1974	4,139.67	1,827	3,496	644	26.26	25
1975	7,177.74	3,123	5,976	1,202	26.55	45
1976	1,091.28	468	895	196	26.85	7
1977	6,710.04	2,835	5,424	1,286	27.14	47
1980	250.51	101	193	57	28.05	2
1982	1,631.45	1,049	1,631			
1983	2,373.67	1,519	2,374			
1985	1,137.79	710	1,138			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 47-L0						
NET SALVAGE PERCENT.. 0						
1987	1,947.22	1,187	1,947			
1988	7.07	4	7			
1993	1,441.13	800	1,441			
1995	797.78	427	798			
1997	1,112.78	575	1,113			
1998	50,846.74	25,673	50,673	174	25.01	7
	750,688.82	430,575	726,792	23,897		948

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.2 0.13

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 24-O3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1931	204.20	204	204			
1936	120.07	107	120			
1941	517.12	408	517			
1942	63.36	49	63			
1943	66.33	50	66			
1945	162.93	115	163			
1946	149.20	103	149			
1947	66.33	44	66			
1948	377.00	245	377			
1949	71.07	45	71			
1950	309.80	189	310			
1952	5,204.61	2,971	5,080	125	10.30	12
1953	1,807.46	997	1,705	103	10.76	10
1957	286.49	137	234	52	12.56	4
1962	1,101.38	426	728	373	14.72	25
1963	4,056.52	1,499	2,563	1,494	15.13	99
1964	170.93	60	103	68	15.54	4
1965	299.84	101	173	127	15.94	8
1966	50.59	16	27	23	16.34	1
1967	1,350.83	409	699	652	16.73	39
1969	2,210.03	599	1,024	1,186	17.49	68
1970	303.35	78	133	170	17.86	10
1972	595.45	134	229	366	18.58	20
1973	346.72	73	125	222	18.92	12
1975	403.54	74	127	277	19.59	14
1976	97.38	17	29	68	19.91	3
1978	28.40	4	7	22	20.51	1
1979	1,083.00	144	246	837	20.80	40
1980	339.25	41	70	269	21.07	13
1983	53.86	37	54			
1984	379.02	261	379			
1986	2,651.47	1,790	2,651			
1987	6,747.73	4,507	6,748			
1988	1,817.19	1,200	1,817			
1989	141.62	93	142			
1990	1,111.30	722	1,111			
1992	5,631.37	3,583	5,631			
1993	4,412.23	2,786	4,412			
1994	19,381.40	12,121	19,381			
1995	442.09	273	442			
1996	495.45	304	495			
1997	2,814.04	1,708	2,814			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 24-O3						
NET SALVAGE PERCENT.. 0						
2005	37.73	21	38			
2006	8,910.59	4,787	8,911			
2007	11,670.35	6,162	11,670			
2011	1,184.07	567	3,267	2,083-		
	89,724.69	50,261	85,373	4,352		383

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.4   0.43

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 335 DRILLING AND CLEANING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-S0.5						
NET SALVAGE PERCENT.. 0						
1956	11,947.50	11,948	11,948			
1967	4,088.00	3,919	4,088			
1968	19,012.74	18,011	19,013			
1972	5,152.00	4,651	5,152			
1981	3,694.10	2,956	3,619	75	5.99	13
1988	4,516.83	3,704	4,517			
1991	1,192.55	938	1,167	26	8.82	3
	49,603.72	46,127	49,503	101		16

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.3 0.03

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 337 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1928	67.99	68	68			
1940	980.88	981	981			
1941	1,425.13	1,425	1,425			
1950	572.00	572	572			
1952	46.00	46	46			
1954	47.17	47	47			
1956	112.81	113	113			
1959	477.96	478	478			
1961	614.73	615	615			
1963	1,381.00	1,381	1,381			
1966	4,766.93	4,767	4,767			
1967	157.76	158	158			
1968	150.15	150	150			
1969	23.17	23	23			
1970	238.47	238	238			
	11,062.15	11,062	11,062			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 70-R4
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1883	45.00	45	45			
1897	69.45	69	69			
1903	3,610.27	3,610	3,610			
1904	4,110.54	4,111	4,111			
1909	44.05	44	44			
1911	85.13	85	85			
1913	835.22	835	835			
1914	222.36	222	222			
1915	14.50	14	15			
1916	224.10	224	224			
1917	117.50	117	118			
1918	64.30	64	64			
1927	6,471.58	6,270	6,439	32	2.18	15
1930	1,806.23	1,732	1,779	28	2.88	10
1931	2,041.31	1,950	2,003	39	3.13	12
1932	27,123.22	25,813	26,509	614	3.38	182
1933	2,640.53	2,503	2,571	70	3.64	19
1934	538.99	509	523	16	3.90	4
1935	812.94	765	786	27	4.16	6
1936	12.64	12	12			
1938	203.24	189	194	9	4.96	2
1939	375.47	347	356	19	5.23	4
1940	962.92	887	911	52	5.51	9
1941	6,450.60	5,917	6,077	374	5.79	65
1942	592.71	541	556	37	6.07	6
1943	337.44	307	315	22	6.37	3
1944	60.01	54	55	5	6.67	1
1945	422.25	380	390	32	6.99	5
1946	631.09	565	580	51	7.31	7
1947	3,351.10	2,985	3,066	286	7.65	37
1948	2,508.33	2,222	2,282	226	8.00	28
1949	4,635.54	4,082	4,192	443	8.36	53
1950	1,157.34	1,013	1,040	117	8.75	13
1951	190.65	166	170	20	9.15	2
1952	4,042.41	3,490	3,584	458	9.57	48
1953	198.20	170	175	24	10.02	2
1954	5,400.53	4,592	4,716	685	10.48	65
1955	14,353.89	12,104	12,431	1,923	10.97	175
1956	8,390.67	7,015	7,204	1,186	11.48	103
1957	78,471.52	65,008	66,762	11,710	12.01	975
1958	2,231.51	1,831	1,880	351	12.57	28
1959	3,854.85	3,131	3,215	639	13.15	49

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1960	3,405.26	2,736	2,810	595	13.76	43
1961	11,197.19	8,897	9,137	2,060	14.38	143
1962	2,660.99	2,090	2,146	515	15.02	34
1963	3,222.41	2,501	2,568	654	15.67	42
1964	3,157.03	2,421	2,486	671	16.33	41
1965	5,365.41	4,062	4,172	1,194	17.01	70
1966	6,572.95	4,911	5,043	1,529	17.70	86
1967	36,334.10	26,789	27,512	8,822	18.39	480
1968	22,318.73	16,229	16,667	5,652	19.10	296
1969	3,796.90	2,722	2,795	1,001	19.81	51
1970	12,470.57	8,811	9,049	3,422	20.54	167
1971	18,015.96	12,539	12,877	5,139	21.28	241
1972	1,199.64	822	844	355	22.03	16
1973	11,935.28	8,051	8,268	3,667	22.78	161
1974	5,080.37	3,371	3,462	1,618	23.55	69
1975	8,346.12	5,445	5,592	2,754	24.33	113
1976	11,480.98	7,361	7,560	3,921	25.12	156
1977	7,995.15	5,034	5,170	2,825	25.93	109
1978	11,905.30	7,357	7,555	4,350	26.74	163
1979	12,918.41	7,832	8,043	4,875	27.56	177
1980	7,570.24	4,500	4,621	2,949	28.39	104
1981	4,856.13	2,828	2,904	1,952	29.23	67
1982	73,749.17	44,073	45,262	28,487	27.94	1,020
1983	10,050.64	5,902	6,061	3,989	28.47	140
1984	9,041.47	5,179	5,319	3,723	29.46	126
1985	15,250.78	8,572	8,803	6,448	29.99	215
1986	26,754.50	14,648	15,043	11,711	30.99	378
1987	14,112.19	7,573	7,777	6,335	31.52	201
1988	3,342.10	1,744	1,791	1,551	32.53	48
1989	11,301.63	5,732	5,887	5,415	33.52	162
1990	1,090.00	540	555	535	34.07	16
1991	8,000.14	3,848	3,952	4,048	35.07	115
1992	117,309.04	54,689	56,164	61,145	36.07	1,695
1993	25,030.74	11,299	11,604	13,427	37.07	362
1994	12,460.42	5,478	5,626	6,835	37.61	182
1995	6,889.97	2,925	3,004	3,886	38.62	101
1996	12,673.77	5,194	5,334	7,340	39.61	185
1997	12,902.15	5,094	5,231	7,671	40.62	189
1998	66,382.78	25,391	26,076	40,307	41.17	979
1999	16,831.93	6,186	6,353	10,479	42.17	248
2000	2,877.07	1,014	1,041	1,836	43.17	43
2001	5,944.43	2,006	2,060	3,884	44.17	88

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
2002	2,355.47	760	781	1,575	45.17	35
2003	1,306.89	402	413	894	46.17	19
2004	373.65	110	113	261	46.73	6
2007	10,611.38	2,644	2,715	7,896	49.72	159
	868,159.56	534,302	548,463	319,697		11,469

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.9 1.32

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 30-R1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1916	44.03	44	44			
1932	22.41	22	22			
1937	428.90	429	429			
1940	2,662.19	2,662	2,662			
1941	342.66	343	343			
1947	195.14	195	195			
1954	97.16	97	97			
1955	398.72	399	399			
1956	1,082.26	1,082	1,082			
1957	2,295.78	2,296	2,296			
1958	310.18	310	310			
1959	2,058.46	2,058	2,058			
1960	300.33	300	300			
1961	6,541.37	6,541	6,541			
1962	4,353.35	4,353	4,353			
1963	2,282.71	2,283	2,283			
1964	736.08	729	736			
1965	190.55	187	191			
1966	2,343.06	2,270	2,343			
1967	2,250.24	2,156	2,250			
1968	9,977.71	9,446	9,978			
1969	2,151.32	2,014	2,151			
1970	544.69	505	545			
1971	40.03	37	40			
1972	1,214.19	1,100	1,214			
1974	700.59	621	701			
1975	4,750.87	4,162	4,751			
1978	193.66	163	192	2	4.70	
1979	2,207.46	1,837	2,161	46	5.04	9
1980	2,203.60	1,808	2,127	76	5.39	14
1984	5,281.99	4,548	5,282			
1985	369.17	314	369			
1986	9,821.44	8,250	9,714	107	7.14	15
1987	241.46	201	237	5	7.36	1
1988	1,014.54	832	980	35	7.79	4
1989	31,015.80	25,039	29,482	1,534	8.24	186
1990	44,844.88	35,755	42,100	2,745	8.52	322
1995	601.90	441	519	83	10.41	8
1997	1,215.58	854	1,006	210	11.24	19
1999	1,575.63	1,054	1,241	335	12.13	28

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
2004	1,760.08	1,019	1,200	560	14.17	40
2019	11,416.29	2,209	2,601	8,815	18.76	470
2020	138.01	22	26	112	18.62	6
	162,216.47	130,987	147,551	14,665		1,122

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.1 0.69

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

CPG
SURVIVOR CURVE.. IOWA 70-R3
NET SALVAGE PERCENT.. 0

1901	71,233.81	71,234	71,234			
1903	24,056.23	24,056	24,056			
1904	33,197.34	33,197	33,197			
1905	1,964.62	1,965	1,965			
1907	2,420.69	2,404	2,421			
1908	8,730.25	8,639	8,730			
1911	749.15	734	749			
1914	1,738.46	1,687	1,738			
1916	77.22	74	77			
1923	35.55	33	36			
1926	1,356.81	1,257	1,357			
1927	46,464.38	42,887	46,464			
1928	2,171.63	1,996	2,172			
1929	180.25	165	180			
1930	27,529.19	25,107	27,529			
1931	2,522.76	2,291	2,523			
1932	296.56	268	297			
1933	122,819.26	110,625	122,819			
1934	4,897.35	4,392	4,897			
1935	10,855.44	9,694	10,855			
1936	1,410.95	1,254	1,411			
1937	16,622.35	14,711	16,622			
1938	2,388.88	2,104	2,389			
1939	2,797.65	2,452	2,798			
1940	797.65	696	798			
1941	11,364.66	9,861	11,365			
1942	11,633.51	10,041	11,634			
1943	1,215.69	1,044	1,216			
1944	5,838.88	4,984	5,839			
1945	48.34	41	48			
1946	1,498.10	1,263	1,483	15	10.97	1
1947	4,905.03	4,110	4,825	80	11.35	7
1948	24,941.60	20,759	24,372	570	11.74	49
1949	98,837.20	81,682	95,898	2,939	12.15	242
1950	28,199.11	23,139	27,166	1,033	12.56	82
1951	2,735.68	2,228	2,616	120	12.99	9
1952	202,177.37	163,388	191,824	10,353	13.43	771
1953	22,207.66	17,801	20,899	1,309	13.89	94
1954	200,020.82	158,989	186,660	13,361	14.36	930
1955	798,248.09	629,019	738,495	59,753	14.84	4,026
1956	81,749.31	63,835	74,945	6,804	15.34	444
1957	1,473,781.22	1,140,073	1,338,494	135,287	15.85	8,535

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
1958	311,182.44	238,409	279,902	31,280	16.37	1,911
1959	299,804.72	227,381	266,955	32,850	16.91	1,943
1960	613,382.05	460,386	540,513	72,869	17.46	4,173
1961	674,919.59	501,081	588,290	86,629	18.03	4,805
1962	47,891.52	35,166	41,286	6,605	18.60	355
1963	190,718.09	138,435	162,529	28,189	19.19	1,469
1964	122,060.87	87,553	102,791	19,270	19.79	974
1965	290,969.66	206,132	242,008	48,962	20.41	2,399
1966	701,420.51	490,693	576,095	125,326	21.03	5,959
1967	720,897.81	497,729	584,355	136,543	21.67	6,301
1968	215,827.53	147,009	172,595	43,233	22.32	1,937
1969	370,389.64	248,794	292,095	78,295	22.98	3,407
1970	640,788.57	424,292	498,137	142,652	23.65	6,032
1971	875,035.93	570,900	670,261	204,775	24.33	8,417
1972	453,960.20	291,701	342,469	111,491	25.02	4,456
1973	966,619.22	611,454	717,873	248,746	25.72	9,671
1974	373,697.43	232,600	273,082	100,615	26.43	3,807
1975	486,480.16	297,867	349,709	136,772	27.14	5,039
1976	297,117.41	178,823	209,946	87,172	27.87	3,128
1977	137,471.87	81,286	95,433	42,039	28.61	1,469
1978	136,380.55	79,198	92,982	43,399	29.35	1,479
1979	287,058.05	163,583	192,053	95,005	30.11	3,155
1980	501,981.46	280,608	329,446	172,536	30.87	5,589
1981	243,613.68	133,500	156,735	86,879	31.64	2,746
1982	283,711.51	167,191	196,289	87,422	28.92	3,023
1983	319,398.12	183,686	215,655	103,743	29.92	3,467
1984	524,887.81	296,457	348,053	176,835	30.43	5,811
1985	749,802.45	415,690	488,038	261,765	30.94	8,460
1986	455,843.70	246,156	288,998	166,846	31.94	5,224
1987	565,064.08	299,032	351,076	213,988	32.47	6,590
1988	414,536.27	214,854	252,248	162,289	32.99	4,919
1989	491,903.15	247,772	290,895	201,008	33.99	5,914
1990	207,476.32	102,161	119,941	87,535	34.53	2,535
1991	360,151.18	173,233	203,383	156,768	35.07	4,470
1992	2,298,208.76	1,071,425	1,257,899	1,040,310	36.07	28,841
1993	1,177,930.89	535,252	628,409	549,522	36.62	15,006
1994	1,136,543.85	499,625	586,581	549,963	37.61	14,623
1995	971,986.45	415,524	487,843	484,144	38.17	12,684
1996	571,723.50	237,380	278,694	293,029	38.73	7,566
1997	818,847.73	327,703	384,737	434,110	39.72	10,929
1998	2,005,922.41	777,496	912,813	1,093,109	40.29	27,131
1999	1,775,496.88	661,195	776,271	999,226	41.29	24,200

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
2000	1,018,766.50	366,348	430,108	588,658	41.86	14,063
2001	2,255,155.44	776,225	911,321	1,343,834	42.86	31,354
2002	827,071.64	273,843	321,503	505,568	43.44	11,638
2003	1,841,712.23	585,296	687,162	1,154,550	44.01	26,234
2004	339,445.60	102,580	120,433	219,012	45.02	4,865
2005	46,687.55	13,474	15,819	30,868	45.60	677
2006	317,437.09	86,660	101,743	215,695	46.60	4,629
2007	479,147.65	124,099	145,698	333,450	47.20	7,065
2008	171,988.56	41,862	49,148	122,841	48.19	2,549
2009	12,014.64	2,753	3,232	8,783	48.79	180
2010	222,615.19	47,484	55,748	166,867	49.79	3,351
2011	140,623.77	27,956	32,822	107,802	50.39	2,139
2012	28,451.16	5,201	6,106	22,345	51.40	435
2013	2,361,672.12	396,761	465,814	1,895,858	52.00	36,459
2014	9,397.12	1,428	1,677	7,721	53.00	146
2021	556,489.83	22,927	26,917	529,573	58.11	9,113
	39,074,496.81	19,067,488	22,345,709	16,728,788		452,101

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.0 1.16

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2						
NET SALVAGE PERCENT.. 0						
1928	43.41	43	43			
1936	1.00	1	1			
1938	63.36	62	63			
1939	130.20	126	130			
1940	199.99	192	200			
1941	188.95	180	189			
1943	115.52	109	116			
1944	207.70	195	208			
1945	83.77	78	84			
1946	174.42	161	174			
1947	163.63	150	164			
1948	277.29	253	277			
1949	89.09	81	89			
1951	7.97	7	8			
1953	18.79	17	19			
1954	5,944.35	5,218	5,944			
1955	8,508.82	7,417	8,509			
1956	7,542.08	6,528	7,542			
1957	39,702.37	34,111	39,702			
1958	13,574.54	11,577	13,575			
1959	6,469.06	5,476	6,469			
1960	9,801.88	8,234	9,798	3	7.84	
1961	24,067.26	20,055	23,866	202	8.17	25
1962	5,498.45	4,544	5,407	91	8.51	11
1963	12,455.03	10,206	12,145	310	8.85	35
1964	5,203.12	4,226	5,029	174	9.20	19
1965	19,172.75	15,428	18,359	813	9.57	85
1966	16,408.17	13,080	15,565	843	9.94	85
1967	43,116.46	34,036	40,503	2,614	10.32	253
1968	18,626.28	14,551	17,316	1,311	10.72	122
1969	18,055.59	13,958	16,610	1,446	11.12	130
1970	32,278.33	24,676	29,365	2,914	11.54	253
1971	15,250.12	11,528	13,718	1,532	11.96	128
1972	26,308.31	19,651	23,385	2,924	12.40	236
1973	26,694.33	19,688	23,429	3,266	12.86	254
1974	12,036.90	8,765	10,430	1,607	13.32	121
1975	18,632.52	13,389	15,933	2,700	13.79	196
1976	30,467.80	21,589	25,691	4,777	14.28	335
1977	138,678.97	96,849	115,251	23,428	14.78	1,585
1978	14,832.80	10,204	12,143	2,690	15.29	176
1979	22,161.07	15,006	17,857	4,304	15.82	272
1980	41,008.38	27,317	32,507	8,501	16.36	520

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2						
NET SALVAGE PERCENT.. 0						
1981	13,577.55	8,895	10,585	2,992	16.90	177
1982	82,437.31	59,866	71,241	11,197	15.65	715
1983	156,845.27	112,427	133,788	23,057	16.00	1,441
1984	24,048.18	16,908	20,121	3,928	16.68	235
1985	50,677.87	35,120	41,793	8,885	17.06	521
1986	86,879.75	59,295	70,561	16,319	17.45	935
1987	86,985.91	58,107	69,148	17,838	18.14	983
1988	52,185.49	34,275	40,787	11,398	18.55	614
1989	411,643.09	265,592	316,055	95,588	18.97	5,039
1990	41,658.60	26,237	31,222	10,436	19.69	530
1991	297,917.74	183,964	218,918	79,000	20.13	3,924
1992	147,610.27	89,275	106,238	41,373	20.58	2,010
1993	264,883.76	156,732	186,512	78,372	21.05	3,723
1994	163,266.69	93,911	111,754	51,512	21.78	2,365
1995	349,935.44	196,454	233,781	116,155	22.26	5,218
1996	117,235.62	64,151	76,340	40,896	22.75	1,798
1997	215,121.50	114,574	136,343	78,778	23.25	3,388
1998	739,635.18	380,986	453,374	286,261	24.00	11,928
1999	555,284.44	277,531	330,263	225,022	24.52	9,177
2000	30,572.58	14,800	17,612	12,961	25.04	518
2001	311,654.86	145,854	173,567	138,088	25.58	5,398
2002	420,021.01	189,639	225,671	194,350	26.12	7,441
2003	302,736.01	131,569	156,567	146,169	26.67	5,481
2004	113,854.85	47,512	56,539	57,315	27.23	2,105
2005	92,462.88	36,948	43,968	48,495	27.80	1,744
2006	61,754.44	23,559	28,035	33,719	28.37	1,189
2007	43,243.40	15,697	18,679	24,564	28.95	848
2008	249,781.89	85,950	102,281	147,501	29.55	4,992
2012	19,034.42	5,078	6,043	12,992	31.60	411
2013	11,199.27	2,764	3,289	7,910	32.05	247
2021	3,931.62	265	315	3,616	34.54	105
	6,152,337.72	3,412,897	4,059,205	2,093,133		90,041

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.2 1.46

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 370 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 23-R0.5						
NET SALVAGE PERCENT.. 0						
1956	5,466.25	5,466	5,466			
1966	7,727.57	7,728	7,728			
1967	1,743.15	1,743	1,743			
1968	249.76	250	250			
1969	2,500.34	2,500	2,500			
1973	1,946.45	1,946	1,946			
1980	706.12	669	706			
1983	5,572.11	5,258	5,572			
1984	1,354.71	1,263	1,355			
1985	2,338.50	2,161	2,339			
1986	8,363.40	7,621	8,363			
1987	1,865.01	1,681	1,865			
1988	8,236.27	7,339	8,236			
1989	56,812.32	49,983	56,812			
1990	6,202.17	5,381	6,202			
1991	81,477.96	69,908	81,478			
1992	19,398.63	16,376	19,399			
1993	11,826.34	9,847	11,826			
1994	4,988.84	4,091	4,989			
1995	24,237.82	19,550	24,238			
1996	53,971.10	42,896	53,659	313	7.10	44
1997	2,814.71	2,193	2,743	71	7.51	9
1998	270.53	207	259	12	7.83	2
2000	83,012.05	60,864	76,135	6,877	8.55	804
2001	21,876.59	15,653	19,580	2,296	8.95	257
2004	19,336.59	12,745	15,943	3,394	10.09	336
2009	239,511.48	131,971	165,082	74,429	11.82	6,297
2010	493,162.42	259,009	323,994	169,168	12.21	13,855
2011	679,759.29	339,880	425,155	254,604	12.50	20,368
2012	572,350.00	271,179	339,217	233,133	12.77	18,256
2013	629,591.21	280,294	350,619	278,972	13.08	21,328
2014	214,236.53	89,144	111,510	102,726	13.33	7,706
2015	223,230.20	85,944	107,507	115,723	13.58	8,522
	3,486,136.42	1,812,740	2,244,418	1,241,718		97,784

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.7   2.80

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 35-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1932	73.41	73	73			
1933	22.79	23	23			
1935	159.65	160	160			
1936	148.67	149	149			
1938	75.60	76	76			
1939	348.00	348	348			
1953	193.45	193	193			
1957	802.14	802	802			
1959	54.05	54	54			
1960	1,630.62	1,613	1,631			
1963	268.78	260	269			
1965	542.39	516	542			
1966	237.71	224	238			
1967	1,610.42	1,507	1,610			
1968	1,046.31	972	1,046			
1969	8,185.23	7,554	8,185			
1970	1,294.81	1,187	1,295			
1971	2,302.48	2,096	2,302			
1972	4,402.26	3,980	4,402			
1973	6,378.34	5,726	6,378			
1974	2,116.13	1,886	2,116			
1975	772.96	684	773			
1976	728.51	640	729			
1977	666.84	581	665	2	4.52	
1978	2,372.22	2,049	2,346	26	4.77	5
1979	395.78	339	388	8	5.03	2
1980	1,489.70	1,264	1,447	42	5.30	8
1981	1,156.83	972	1,113	44	5.58	8
1982	1,410.00	1,246	1,410			
1983	4,310.08	3,770	4,310			
1984	3,348.16	2,896	3,317	31	6.16	5
1985	3,634.15	3,120	3,574	61	6.34	10
1986	5,292.73	4,486	5,138	155	6.75	23
1987	1,466.52	1,231	1,410	57	6.98	8
1988	1,617.48	1,338	1,533	85	7.42	11
1989	7,215.84	5,875	6,729	487	7.87	62
1990	11,462.74	9,177	10,511	952	8.34	114
1991	14,888.28	11,759	13,468	1,420	8.65	164
1992	14,350.24	11,120	12,737	1,614	9.15	176
1993	10,561.54	8,020	9,186	1,376	9.66	142

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1994	9,905.10	7,363	8,433	1,472	10.18	145
1995	3,879.74	2,820	3,230	650	10.71	61
1996	7,818.56	5,568	6,377	1,441	11.11	130
	140,637.24	115,717	130,718	9,919		1,074

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.2 0.76

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371.1 TESTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 20-R3						
NET SALVAGE PERCENT.. 0						
1983	15,664.23	15,664	15,664			
1984	11,125.29	11,125	11,125			
1986	4,384.63	4,385	4,385			
1987	38,021.86	38,022	38,022			
1991	11,962.90	11,937	11,963			
1992	2,199.99	2,169	2,200			
1993	1,383.30	1,354	1,383			
1996	24,385.78	23,137	24,386			
1997	494.25	465	494			
2015	100,388.74	44,542	48,001	52,388	10.66	4,914
	210,010.97	152,800	157,623	52,388		4,914

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.7 2.34

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1904	298.00	291	298			
1905	222.17	216	222			
1930	410.41	364	410			
1931	548.08	485	548			
1932	10,677.87	9,401	10,678			
1933	38.71	34	39			
1934	55.00	48	55			
1935	123.52	107	123	1	9.88	
1936	533.10	461	530	4	10.20	
1937	100.54	86	99	2	10.53	
1938	223.29	191	219	4	10.87	
1939	178.56	152	175	4	11.22	
1940	285.78	242	278	8	11.59	1
1941	249.96	210	241	9	11.96	1
1942	57.82	48	55	3	12.34	
1943	19.44	16	18	1	12.74	
1945	36.92	30	34	2	13.56	
1946	59.80	49	56	4	14.00	
1947	160.11	129	148	12	14.44	1
1948	235.63	189	217	19	14.90	1
1949	51.03	41	47	4	15.37	
1950	2,077.70	1,639	1,883	195	15.85	12
1951	1,726.56	1,350	1,551	176	16.35	11
1952	360.18	279	321	40	16.85	2
1953	287.05	221	254	33	17.37	2
1954	1,145.40	872	1,002	144	17.91	8
1955	877.98	662	761	117	18.45	6
1956	3,133.21	2,339	2,687	446	19.01	23
1957	1,794.30	1,326	1,523	271	19.58	14
1958	5,277.55	3,859	4,433	844	20.16	42
1959	1,136.57	822	944	192	20.75	9
1960	1,431.64	1,024	1,176	255	21.36	12
1961	1,139.60	806	926	214	21.98	10
1962	1,739.80	1,216	1,397	343	22.60	15
1963	534.64	369	424	111	23.24	5
1964	1,024.78	698	802	223	23.89	9
1965	2,424.42	1,631	1,874	551	24.55	22
1966	1,904.74	1,264	1,452	453	25.22	18
1967	14,200.26	9,298	10,682	3,519	25.89	136
1968	36,083.66	23,296	26,762	9,321	26.58	351
1969	18,362.30	11,683	13,421	4,941	27.28	181
1970	11,282.03	7,073	8,125	3,157	27.98	113

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1971	6,080.40	3,754	4,313	1,768	28.70	62
1972	15,534.05	9,441	10,846	4,688	29.42	159
1973	18,498.57	11,062	12,708	5,791	30.15	192
1974	38,364.70	22,563	25,920	12,444	30.89	403
1975	49,272.90	28,486	32,725	16,548	31.64	523
1976	37,863.68	21,511	24,712	13,152	32.39	406
1977	13,898.67	7,755	8,909	4,990	33.15	151
1978	19,181.60	10,506	12,069	7,112	33.92	210
1979	24,833.70	13,344	15,330	9,504	34.70	274
1980	27,735.34	14,611	16,785	10,950	35.49	309
1981	38,526.40	19,890	22,850	15,677	36.28	432
1982	41,644.61	23,159	26,605	15,040	33.13	454
1983	29,660.39	16,218	18,631	11,029	33.57	329
1984	47,020.30	25,071	28,802	18,219	34.58	527
1985	51,245.11	26,832	30,825	20,420	35.03	583
1986	70,214.20	35,809	41,137	29,077	36.03	807
1987	74,675.20	37,338	42,894	31,781	36.50	871
1988	61,590.79	29,958	34,416	27,175	37.49	725
1989	64,488.00	30,703	35,272	29,216	37.96	770
1990	63,293.80	29,261	33,615	29,679	38.96	762
1991	76,971.45	34,776	39,951	37,021	39.44	939
1992	69,790.71	30,778	35,358	34,433	39.93	862
1993	74,877.76	31,973	36,731	38,147	40.93	932
1994	94,389.03	39,266	45,109	49,280	41.42	1,190
1995	63,758.76	25,618	29,430	34,329	42.43	809
1996	64,141.55	25,047	28,774	35,368	42.92	824
1997	72,745.02	27,374	31,447	41,298	43.92	940
1998	147,067.21	53,621	61,600	85,467	44.43	1,924
1999	227,532.44	79,727	91,591	135,942	45.43	2,992
2000	113,292.57	38,338	44,043	69,250	45.94	1,507
2001	143,018.46	46,338	53,233	89,785	46.94	1,913
2002	79,103.65	24,490	28,134	50,969	47.94	1,063
2003	48,457.78	14,402	16,545	31,913	48.47	658
2004	457,077.76	129,262	148,496	308,581	49.46	6,239
2005	156,879.83	42,373	48,678	108,202	49.99	2,164
2006	18,899.98	4,829	5,548	13,352	50.99	262
2007	23,188.64	5,626	6,463	16,725	51.52	325
2008	111,323.88	25,360	29,134	82,190	52.53	1,565
2009	31,652.25	6,793	7,804	23,848	53.07	449
2010	18,984.06	3,793	4,357	14,627	54.07	271
2011	16,496.41	3,072	3,529	12,967	54.62	237
2012	11,716.78	2,008	2,307	9,410	55.61	169

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
2013	7,230.17	1,131	1,299	5,931	56.62	105
2014	96,772.18	13,790	15,842	80,930	57.17	1,416
2015	3,854.69	491	564	3,291	58.17	57
2016	108,433.77	12,275	14,102	94,332	58.73	1,606
2017	1,733.31	170	195	1,538	59.72	26
2018	88,813.28	7,425	8,530	80,283	60.29	1,332
2019	734.26	51	59	676	60.86	11
2020	180,290.57	9,664	11,102	169,189	61.86	2,735
2021	19,208.11	740	850	18,358	62.44	294
	3,544,568.84	1,242,390	1,427,058	2,117,511		45,770

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.3 1.29

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1849	2,794.87	2,795	2,795			
1867	72.39	72	72			
1888	4,192.87	4,193	4,193			
1897	178.89	179	179			
1898	159.45	159	159			
1902	1,745.39	1,745	1,745			
1905	1,321.50	1,322	1,322			
1906	2,135.22	2,135	2,135			
1908	880.43	880	880			
1909	1,063.58	1,064	1,064			
1910	681.05	681	681			
1912	356.78	357	357			
1916	122.09	122	122			
1917	5,254.50	5,254	5,255			
1918	4,743.98	4,744	4,744			
1919	2,219.29	2,219	2,219			
1920	2,532.43	2,532	2,532			
1921	17,407.66	17,408	17,408			
1922	1,544.59	1,545	1,545			
1923	444.90	445	445			
1924	49,481.98	49,235	49,482			
1925	9,550.78	9,444	9,551			
1926	1,437.54	1,411	1,438			
1927	12,634.65	12,316	12,635			
1928	169.18	164	169			
1929	1,786.94	1,717	1,787			
1930	6,130.68	5,850	6,131			
1931	886.67	840	887			
1932	690.68	650	691			
1933	4,845.58	4,525	4,846			
1934	599.15	556	599			
1937	206.12	187	206			
1939	941.28	841	941			
1941	1,497.83	1,318	1,498			
1942	1,321.59	1,155	1,319	3	6.32	
1943	3,799.03	3,293	3,760	39	6.66	6
1944	480.46	413	472	9	7.00	1
1945	7,388.06	6,303	7,196	192	7.34	26
1946	24,241.93	20,518	23,427	815	7.68	106
1947	1,212.46	1,018	1,162	50	8.02	6
1948	11,813.70	9,838	11,233	581	8.36	69
1949	155,416.10	128,374	146,572	8,844	8.70	1,017

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

UGI-GAS
SURVIVOR CURVE.. IOWA 50-S0.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1950	314,773.72	257,800	294,345	20,429	9.05	2,257
1951	117,565.93	95,464	108,997	8,569	9.40	912
1952	14,011.46	11,279	12,878	1,134	9.75	116
1953	64,035.02	51,100	58,344	5,691	10.10	563
1954	82,747.60	65,453	74,731	8,016	10.45	767
1955	21,708.32	17,015	19,427	2,281	10.81	211
1956	33,265.27	25,834	29,496	3,769	11.17	337
1957	17,019.75	13,095	14,951	2,068	11.53	179
1958	16,398.95	12,499	14,271	2,128	11.89	179
1959	36,119.98	27,263	31,128	4,992	12.26	407
1960	28,812.28	21,534	24,587	4,226	12.63	335
1961	30,404.90	22,500	25,689	4,715	13.00	363
1962	27,753.65	20,327	23,208	4,545	13.38	340
1963	14,913.85	10,810	12,342	2,571	13.76	187
1964	4,880.13	3,500	3,996	884	14.14	63
1965	18,536.25	13,153	15,018	3,519	14.52	242
1966	5,038.93	3,536	4,037	1,002	14.91	67
1967	4,718.58	3,274	3,738	980	15.31	64
1968	4,278.86	2,935	3,351	928	15.70	59
1969	8,771.59	5,945	6,788	1,984	16.11	123
1970	5,741.53	3,846	4,391	1,350	16.51	82
1971	36,049.81	23,851	27,232	8,818	16.92	521
1973	11,871.49	7,657	8,742	3,129	17.75	176
1974	25,525.37	16,244	18,547	6,979	18.18	384
1975	87,663.74	55,035	62,837	24,827	18.61	1,334
1976	4,598.73	2,848	3,252	1,347	19.04	71
1977	8,040.17	4,908	5,604	2,436	19.48	125
1978	13,389.00	8,052	9,193	4,196	19.93	211
1979	6,024.51	3,569	4,075	1,950	20.38	96
1980	2,625.97	1,532	1,749	877	20.83	42
1981	3,896.41	2,237	2,554	1,342	21.29	63
1982	4,195.18	2,890	3,300	896	18.74	48
1984	107,312.77	72,061	82,276	25,037	19.32	1,296
1985	3,250.91	2,153	2,458	793	19.64	40
1987	11,800.00	7,538	8,607	3,193	20.64	155
1989	18,115.32	11,250	12,845	5,271	21.06	250
1990	3,722.71	2,270	2,592	1,131	21.45	53
1993	4,421.64	2,535	2,894	1,527	22.69	67
1995	3,605.96	1,983	2,264	1,342	23.32	58
1996	28,053.64	15,042	17,174	10,879	23.78	457
1998	37,254.30	19,000	21,693	15,561	24.50	635
1999	24,770.91	12,321	14,068	10,703	24.76	432

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2000	23,959.75	11,544	13,180	10,779	25.28	426
2001	34,304.98	16,055	18,331	15,974	25.58	624
2002	6,262.15	2,841	3,244	3,018	25.90	117
2003	8,507.00	3,714	4,240	4,267	26.45	161
2004	14,150.50	5,960	6,805	7,346	26.80	274
2005	14,063.28	5,698	6,506	7,558	27.16	278
2006	17,523.06	6,808	7,773	9,750	27.55	354
2007	55,195.64	20,489	23,393	31,802	27.95	1,138
2008	20,558.92	7,266	8,296	12,263	28.36	432
2011	27,987.49	8,326	9,506	18,481	29.52	626
2013	103,921.61	26,729	30,518	73,404	30.32	2,421
2014	188,343.09	44,374	50,664	137,679	30.82	4,467
2019	56,478.77	6,811	7,776	48,702	32.81	1,484
2020	20,252.13	1,936	2,210	18,042	33.13	545
2021	8,253.67	574	655	7,598	33.47	227
	2,263,831.38	1,442,080	1,628,618	635,213		29,172
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1901	435.33	435	435			
1914	47.48	47	47			
1922	4,142.29	4,142	4,142			
1927	2,693.18	2,625	2,693			
1930	189.29	181	189			
1933	847.72	792	848			
1936	544.45	497	544			
1938	32.84	30	33			
1952	9,309.40	7,494	9,309			
1956	5,775.22	4,485	5,622	153	11.17	14
1957	65,555.21	50,438	63,230	2,325	11.53	202
1958	3,928.05	2,994	3,753	175	11.89	15
1959	1,740.26	1,314	1,647	93	12.26	8
1960	10,837.04	8,100	10,154	683	12.63	54
1961	15,330.33	11,344	14,221	1,109	13.00	85
1962	44,412.35	32,528	40,778	3,635	13.38	272
1963	61,579.91	44,633	55,953	5,627	13.76	409
1964	33,613.04	24,107	30,221	3,392	14.14	240
1965	24,530.54	17,407	21,822	2,709	14.52	187

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

PNG
SURVIVOR CURVE.. IOWA 50-S0.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1966	16,505.84	11,584	14,522	1,984	14.91	133
1967	43,814.66	30,399	38,109	5,706	15.31	373
1968	27,948.53	19,173	24,036	3,913	15.70	249
1969	34,014.41	23,055	28,902	5,112	16.11	317
1970	109,477.63	73,328	91,926	17,552	16.51	1,063
1971	28,682.10	18,976	23,789	4,893	16.92	289
1972	14,929.02	9,752	12,225	2,704	17.34	156
1973	43,388.65	27,986	35,084	8,305	17.75	468
1974	6,679.10	4,251	5,329	1,350	18.18	74
1975	2,388.78	1,500	1,880	508	18.61	27
1976	325.75	202	253	73	19.04	4
1977	310.42	189	237	73	19.48	4
1978	5,350.19	3,218	4,034	1,316	19.93	66
1979	1,782.45	1,056	1,324	459	20.38	23
1980	6,278.95	3,663	4,592	1,687	20.83	81
1981	51,214.65	29,407	36,865	14,349	21.29	674
1982	55,560.11	38,275	47,982	7,578	18.74	404
1983	28,861.79	19,638	24,619	4,243	19.02	223
1984	5,806.34	3,899	4,888	918	19.32	48
1985	10,388.00	6,879	8,624	1,764	19.64	90
1986	10,162.46	6,593	8,265	1,897	20.30	93
1987	22,171.50	14,163	17,755	4,416	20.64	214
1988	9,500.30	6,003	7,525	1,975	20.68	96
1989	21,764.75	13,516	16,944	4,821	21.06	229
1990	17,697.49	10,790	13,527	4,171	21.45	194
1991	2,527.62	1,512	1,895	632	21.85	29
1992	778.74	456	572	207	22.26	9
1993	14,187.04	8,135	10,198	3,989	22.69	176
1994	30,706.90	17,300	21,688	9,019	22.86	395
1995	14,521.42	7,987	10,013	4,509	23.32	193
1996	64,620.77	34,650	43,438	21,183	23.78	891
1997	90,222.73	47,340	59,346	30,876	24.01	1,286
1998	90,466.61	46,138	57,840	32,627	24.50	1,332
1999	26,987.42	13,424	16,829	10,159	24.76	410
2000	22,242.63	10,716	13,434	8,809	25.28	348
2001	27,792.71	13,007	16,306	11,487	25.58	449
2002	74,704.50	33,886	42,480	32,224	25.90	1,244
2003	35,723.93	15,597	19,553	16,171	26.45	611
2004	12,600.58	5,307	6,653	5,948	26.80	222
2005	1,094.30	443	555	539	27.16	20
2006	2,275.29	884	1,108	1,167	27.55	42
2007	50,329.62	18,682	23,420	26,909	27.95	963

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2008	4,380.00	1,548	1,941	2,439	28.36	86
2009	6,511.91	2,181	2,734	3,778	28.79	131
2010	2,023.74	642	805	1,219	29.06	42
2014	1,151,949.73	271,399	340,232	811,718	30.82	26,337
2017	18,705.63	3,161	3,963	14,743	31.96	461
2019	87,261.18	10,524	13,193	74,068	32.81	2,257
2020	35,549.59	3,399	4,261	31,289	33.13	944
	2,728,712.39	1,159,406	1,451,336	1,277,376		45,956
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1862	16.00	16	16			
1901	123.38	123	123			
1903	2,860.00	2,860	2,860			
1909	2,901.80	2,902	2,902			
1911	7,556.70	7,557	7,557			
1916	161.12	161	161			
1924	266.11	265	266			
1926	212.80	209	213			
1928	13,724.13	13,282	13,724			
1929	894.16	859	894			
1931	38.28	36	38			
1937	572.62	519	573			
1938	4,600.60	4,142	4,601			
1946	12.36	10	12			
1948	432.79	360	433			
1949	6,857.71	5,664	6,858			
1950	1,464.38	1,199	1,464			
1951	23,781.96	19,311	23,782			
1953	8.07	6	8			
1954	1,809.10	1,431	1,809			
1955	0.60			1	10.81	
1956	768.66	597	769			
1957	123.78	95	123	1	11.53	
1958	1,865.14	1,422	1,843	22	11.89	2
1960	2,255.90	1,686	2,185	71	12.63	6
1961	2,692.32	1,992	2,581	111	13.00	9
1962	2,889.36	2,116	2,742	147	13.38	11

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 50-S0.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1963	2,147.00	1,556	2,016	131	13.76	10
1964	1,552.28	1,113	1,442	110	14.14	8
1965	251.74	179	232	20	14.52	1
1966	898.68	631	818	81	14.91	5
1967	2,957.44	2,052	2,659	298	15.31	19
1968	6,310.72	4,329	5,610	701	15.70	45
1969	8,455.01	5,731	7,427	1,028	16.11	64
1970	1,245.94	835	1,082	164	16.51	10
1971	15,473.04	10,237	13,266	2,207	16.92	130
1972	1,369.67	895	1,160	210	17.34	12
1973	1,726.18	1,113	1,442	284	17.75	16
1974	486.52	310	402	85	18.18	5
1975	909.12	571	740	169	18.61	9
1976	1,641.93	1,017	1,318	324	19.04	17
1978	1,522.09	915	1,186	336	19.93	17
1981	1,579.82	907	1,175	404	21.29	19
1985	1,166.22	772	1,000	166	19.64	8
1986	57,181.74	37,100	48,077	9,105	20.30	449
1987	5,760.94	3,680	4,769	992	20.64	48
1989	3,798.31	2,359	3,057	741	21.06	35
1990	1,768.35	1,078	1,397	371	21.45	17
1991	2,041.00	1,221	1,582	459	21.85	21
1992	2,626.45	1,539	1,994	632	22.26	28
1995	422.40	232	301	122	23.32	5
1996	825.00	442	573	252	23.78	11
1997	2,848.85	1,495	1,937	912	24.01	38
1998	2,075.00	1,058	1,371	704	24.50	29
2003	2,542.54	1,110	1,438	1,104	26.45	42
2005	5,268.60	2,135	2,767	2,502	27.16	92
2006	3,944.55	1,532	1,985	1,959	27.55	71
2007	1,852.48	688	892	961	27.95	34
2011	2,856.60	850	1,101	1,755	29.52	59
2012	17,301.02	4,796	6,215	11,086	29.99	370
2016	21,621.02	4,151	5,379	16,242	31.56	515
2017	68,032.91	11,498	14,900	53,133	31.96	1,662

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2018	210,544.81	30,571	39,616	170,929	32.38	5,279
2020	11,411.86	1,091	1,414	9,998	33.13	302
2021	8,525.00	592	767	7,758	33.47	232
	561,832.66	211,201	263,043	298,790		9,762
	5,554,376.43	2,812,687	3,342,997	2,211,379		84,890

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.0 1.53

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1924	117,524.05	103,341	110,428	7,096	8.81	805
1925	19,792.99	17,339	18,528	1,265	9.05	140
1926	327,075.13	285,406	304,979	22,096	9.30	2,376
1927	31,347.32	27,251	29,120	2,227	9.54	233
1928	128,009.90	110,842	118,444	9,566	9.79	977
1929	141,316.00	121,861	130,218	11,098	10.05	1,104
1930	317,128.65	272,341	291,018	26,111	10.31	2,533
1931	181,855.81	155,525	166,191	15,665	10.57	1,482
1932	18,283.96	15,569	16,637	1,647	10.84	152
1933	10,350.64	8,774	9,376	975	11.12	88
1934	20,611.60	17,393	18,586	2,026	11.40	178
1935	14,656.50	12,309	13,153	1,503	11.69	129
1936	7,201.97	6,019	6,432	770	11.99	64
1937	10,419.33	8,664	9,258	1,161	12.30	94
1938	7,837.49	6,484	6,929	909	12.61	72
1939	20,680.02	17,014	18,181	2,499	12.94	193
1940	20,294.92	16,606	17,745	2,550	13.27	192
1941	30,977.52	25,202	26,930	4,047	13.61	297
1942	29,010.17	23,458	25,067	3,943	13.97	282
1943	4,261.20	3,425	3,660	601	14.33	42
1944	5,523.84	4,411	4,714	810	14.71	55
1945	9,688.53	7,684	8,211	1,478	15.10	98
1946	356,888.25	281,110	300,388	56,500	15.50	3,645
1947	60,224.69	47,099	50,329	9,896	15.91	622
1948	122,690.61	95,245	101,777	20,914	16.33	1,281
1949	137,193.14	105,676	112,923	24,270	16.77	1,447
1950	1,729,827.72	1,321,779	1,412,426	317,402	17.22	18,432
1951	359,883.56	272,774	291,481	68,403	17.67	3,871
1952	667,403.55	501,560	535,957	131,447	18.14	7,246
1953	741,311.69	552,122	589,986	151,325	18.63	8,123
1954	1,389,325.39	1,025,433	1,095,757	293,569	19.12	15,354
1955	1,191,862.60	871,371	931,129	260,733	19.63	13,282
1956	1,778,080.19	1,287,277	1,375,558	402,522	20.15	19,976
1957	1,512,044.11	1,083,697	1,158,017	354,028	20.68	17,119
1958	3,013,386.24	2,137,455	2,284,041	729,345	21.22	34,371
1959	1,809,517.12	1,269,883	1,356,971	452,546	21.77	20,788
1960	2,918,636.78	2,025,855	2,164,788	753,849	22.33	33,759
1961	1,730,544.35	1,187,430	1,268,864	461,681	22.91	20,152
1962	1,885,496.27	1,278,781	1,366,479	519,017	23.49	22,095
1963	2,308,673.44	1,546,811	1,652,891	655,783	24.09	27,222
1964	2,273,743.96	1,504,718	1,607,911	665,833	24.69	26,968
1965	2,876,914.86	1,879,460	2,008,353	868,562	25.31	34,317

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1966	3,009,864.43	1,940,730	2,073,825	936,040	25.93	36,099
1967	3,182,724.51	2,024,722	2,163,577	1,019,148	26.56	38,372
1968	3,574,135.95	2,241,913	2,395,663	1,178,473	27.21	43,310
1969	3,949,882.55	2,442,449	2,609,951	1,339,931	27.86	48,095
1970	3,334,632.39	2,031,858	2,171,202	1,163,430	28.52	40,793
1971	3,164,658.83	1,899,238	2,029,487	1,135,172	29.19	38,889
1972	3,069,126.45	1,813,301	1,937,657	1,131,470	29.87	37,880
1973	2,865,197.80	1,666,141	1,780,404	1,084,793	30.55	35,509
1974	3,100,086.58	1,773,405	1,895,025	1,205,062	31.24	38,574
1975	2,234,043.95	1,256,270	1,342,425	891,619	31.95	27,907
1976	1,976,731.58	1,092,619	1,167,550	809,181	32.65	24,783
1977	2,479,519.10	1,346,081	1,438,395	1,041,124	33.37	31,199
1978	2,362,182.75	1,258,760	1,345,085	1,017,097	34.10	29,827
1979	4,438,610.14	2,320,860	2,480,024	1,958,586	34.83	56,233
1980	9,367,708.68	4,804,510	5,134,002	4,233,707	35.56	119,058
1981	6,463,576.46	3,248,594	3,471,382	2,992,195	36.31	82,407
1982	6,934,784.63	3,884,866	4,151,289	2,783,496	32.58	85,436
1983	1,658,447.61	913,473	976,119	682,329	33.03	20,658
1984	2,317,946.18	1,254,472	1,340,503	977,443	33.49	29,186
1985	3,038,554.91	1,602,534	1,712,435	1,326,120	34.50	38,438
1986	4,862,918.13	2,516,560	2,689,145	2,173,773	34.96	62,179
1987	2,063,634.49	1,047,088	1,118,897	944,738	35.44	26,657
1988	4,170,864.53	2,057,905	2,199,035	1,971,829	36.45	54,097
1989	3,555,060.99	1,717,094	1,834,852	1,720,209	36.93	46,580
1990	3,310,454.89	1,563,859	1,671,108	1,639,347	37.42	43,809
1991	3,115,342.50	1,427,450	1,525,344	1,589,998	38.43	41,374
1992	2,423,437.12	1,084,003	1,158,344	1,265,094	38.92	32,505
1993	1,063,382.75	463,848	495,659	567,724	39.43	14,398
1994	867,663.26	368,583	393,860	473,803	39.94	11,863
1995	5,073,786.26	2,082,282	2,225,084	2,848,702	40.94	69,582
1996	4,983,926.96	1,987,590	2,123,898	2,860,029	41.46	68,983
1997	1,932,953.67	747,860	799,148	1,133,806	41.99	27,002
1998	2,318,945.30	863,343	922,551	1,396,395	42.99	32,482
1999	1,115,874.73	401,938	429,503	686,372	43.52	15,771
2000	2,568,690.55	893,391	954,659	1,614,031	44.07	36,624
2001	5,868,334.55	1,967,066	2,101,967	3,766,368	44.62	84,410
2002	1,049,473.46	336,251	359,311	690,162	45.61	15,132
2003	3,324,034.72	1,022,141	1,092,239	2,231,796	46.17	48,339
2004	1,756,088.91	516,993	552,448	1,203,641	46.73	25,757
2005	1,026,103.09	288,540	308,328	717,775	47.29	15,178
2006	2,688,938.54	720,098	769,482	1,919,456	47.86	40,106
2007	918,820.92	231,910	247,814	671,007	48.86	13,733

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
2008	2,252,682.75	537,715	574,591	1,678,091	49.44	33,942
2009	2,518,210.60	566,094	604,917	1,913,294	50.01	38,258
2010	2,200,218.86	463,366	495,143	1,705,075	50.60	33,697
2011	1,838,236.19	360,662	385,396	1,452,840	51.20	28,376
2012	2,620,954.19	476,227	508,887	2,112,068	51.79	40,781
2013	3,402,845.86	568,275	607,247	2,795,599	52.39	53,361
2014	4,917,845.88	747,513	798,777	4,119,069	53.00	77,718
2015	9,553,655.71	1,306,940	1,396,570	8,157,086	53.61	152,156
2016	12,494,665.19	1,526,848	1,631,559	10,863,106	53.85	201,729
2017	23,573,116.91	2,512,894	2,685,228	20,887,889	54.48	383,405
2018	19,145,104.15	1,747,948	1,867,822	17,277,282	54.74	315,624
2019	10,717,469.45	805,954	861,226	9,856,243	55.38	177,975
2020	11,037,270.04	656,718	701,756	10,335,515	55.32	186,831
2021	24,798,333.02	1,066,328	1,139,456	23,658,877	55.64	425,213
2022	2,154,001.89	57,296	61,225	2,092,777	54.99	38,057
2023	1,095,983.78	10,302	11,009	1,084,975	52.97	20,483
	297,239,236.33	100,076,123	106,939,313	190,299,923		4,278,476
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1901	2,762.63	2,632	2,477	286	3.45	83
1903	549.49	519	488	61	4.00	15
1904	356.46	336	316	40	4.26	9
1905	1,648.72	1,547	1,456	193	4.51	43
1906	4,388.63	4,102	3,860	528	4.76	111
1907	11,462.91	10,679	10,049	1,414	4.99	283
1908	23,385.73	21,713	20,433	2,953	5.22	566
1909	464.93	430	405	60	5.45	11
1910	9,184.27	8,471	7,972	1,213	5.67	214
1911	1,080.24	993	934	146	5.89	25
1912	1,087.59	997	938	149	6.11	24
1913	2,406.02	2,198	2,068	338	6.32	53
1914	449.97	410	386	64	6.54	10
1915	191.50	174	164	28	6.76	4
1916	301.24	272	256	45	6.98	6
1917	305.25	275	259	46	7.20	6
1918	1,466.39	1,317	1,239	227	7.42	31
1919	3,165.70	2,834	2,667	499	7.65	65

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

PNG
SURVIVOR CURVE.. IOWA 73-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1920	8,438.69	7,528	7,084	1,355	7.88	172
1921	43,335.10	38,521	36,250	7,085	8.11	874
1922	27,733.36	24,565	23,117	4,617	8.34	554
1923	42,376.58	37,396	35,191	7,185	8.58	837
1924	49,538.88	43,561	40,993	8,546	8.81	970
1925	49,118.10	43,029	40,492	8,626	9.05	953
1926	13,939.44	12,164	11,447	2,493	9.30	268
1927	37,623.61	32,707	30,779	6,845	9.54	718
1928	10,565.60	9,149	8,610	1,956	9.79	200
1929	2,652.27	2,287	2,152	500	10.05	50
1930	107,014.53	91,901	86,482	20,532	10.31	1,991
1931	236,981.30	202,669	190,719	46,262	10.57	4,377
1932	7,093.52	6,040	5,684	1,410	10.84	130
1933	12,521.67	10,614	9,988	2,533	11.12	228
1934	2,759.77	2,329	2,192	568	11.40	50
1935	3,014.40	2,532	2,383	632	11.69	54
1936	21,749.83	18,177	17,105	4,645	11.99	387
1937	4,376.03	3,639	3,424	952	12.30	77
1938	3,631.81	3,004	2,827	805	12.61	64
1939	2,650.80	2,181	2,052	598	12.94	46
1940	12,640.01	10,342	9,732	2,908	13.27	219
1941	6,154.05	5,007	4,712	1,442	13.61	106
1942	5,168.27	4,179	3,933	1,236	13.97	88
1943	1,868.79	1,502	1,413	455	14.33	32
1944	2,359.58	1,884	1,773	587	14.71	40
1945	1,897.76	1,505	1,416	481	15.10	32
1946	74,361.53	58,572	55,119	19,243	15.50	1,241
1947	15,086.11	11,798	11,102	3,984	15.91	250
1948	8,562.61	6,647	6,255	2,308	16.33	141
1949	15,102.99	11,633	10,947	4,156	16.77	248
1950	9,174.75	7,011	6,598	2,577	17.22	150
1951	14,574.62	11,047	10,396	4,179	17.67	237
1952	177,511.26	133,401	125,536	51,976	18.14	2,865
1953	422,609.78	314,756	296,198	126,412	18.63	6,785
1954	7,582.16	5,596	5,266	2,316	19.12	121
1955	105,014.65	76,776	72,249	32,765	19.63	1,669
1956	634,163.34	459,115	432,045	202,118	20.15	10,031
1957	1,596,094.47	1,143,937	1,076,490	519,605	20.68	25,126
1958	177,831.06	126,139	118,702	59,129	21.22	2,786
1959	1,138,564.98	799,022	751,911	386,654	21.77	17,761
1960	635,821.35	441,330	415,309	220,513	22.33	9,875
1961	1,291,115.90	885,912	833,678	457,438	22.91	19,967

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1962	1,014,827.39	688,276	647,695	367,133	23.49	15,629
1963	1,793,941.74	1,201,941	1,131,074	662,868	24.09	27,516
1964	2,986,253.35	1,976,243	1,859,722	1,126,531	24.69	45,627
1965	2,315,360.94	1,512,602	1,423,418	891,943	25.31	35,241
1966	2,078,912.59	1,340,462	1,261,427	817,485	25.93	31,527
1967	2,237,289.89	1,423,274	1,339,357	897,933	26.56	33,808
1968	3,354,780.99	2,104,320	1,980,248	1,374,533	27.21	50,516
1969	3,063,995.02	1,894,652	1,782,942	1,281,053	27.86	45,982
1970	2,480,602.68	1,511,481	1,422,363	1,058,240	28.52	37,105
1971	2,266,592.00	1,360,273	1,280,070	986,522	29.19	33,797
1972	3,294,640.16	1,946,539	1,831,770	1,462,871	29.87	48,975
1973	1,214,345.26	706,154	664,519	549,827	30.55	17,998
1974	544,587.05	311,531	293,163	251,424	31.24	8,048
1975	614,448.90	345,523	325,151	289,298	31.95	9,055
1976	409,060.77	226,104	212,773	196,288	32.65	6,012
1977	611,035.17	331,719	312,161	298,875	33.37	8,956
1978	579,845.70	308,988	290,770	289,076	34.10	8,477
1979	1,014,432.98	530,427	499,153	515,280	34.83	14,794
1980	1,097,509.60	562,891	529,702	567,807	35.56	15,968
1981	3,053,708.68	1,534,794	1,444,301	1,609,407	36.31	44,324
1982	4,829,613.38	2,705,549	2,546,028	2,283,586	32.58	70,092
1983	851,174.78	468,827	441,185	409,990	33.03	12,413
1984	1,856,707.68	1,004,850	945,603	911,104	33.49	27,205
1985	1,831,873.05	966,130	909,166	922,707	34.50	26,745
1986	1,669,942.83	864,195	813,241	856,701	34.96	24,505
1987	2,021,990.53	1,025,958	965,467	1,056,524	35.44	29,812
1988	1,972,567.27	973,265	915,881	1,056,687	36.45	28,990
1989	1,594,924.28	770,348	724,928	869,997	36.93	23,558
1990	1,291,371.71	610,044	574,075	717,296	37.42	19,169
1991	833,245.87	381,793	359,282	473,964	38.43	12,333
1992	2,816,786.46	1,259,949	1,185,661	1,631,125	38.92	41,910
1993	858,611.91	374,527	352,445	506,167	39.43	12,837
1994	1,534,004.46	651,645	613,223	920,781	39.94	23,054
1995	1,209,466.80	496,365	467,099	742,368	40.94	18,133
1996	8,873,540.97	3,538,768	3,330,119	5,543,422	41.46	133,705
1997	7,737,465.43	2,993,625	2,817,118	4,920,347	41.99	117,179
1998	3,544,884.82	1,319,761	1,241,947	2,302,938	42.99	53,569
1999	442,401.30	159,353	149,957	292,444	43.52	6,720
2000	8,082,092.64	2,810,952	2,645,216	5,436,877	44.07	123,369
2001	2,152,117.88	721,390	678,856	1,473,262	44.62	33,018
2002	5,043,320.62	1,615,880	1,520,606	3,522,714	45.61	77,236
2003	1,731,585.79	532,463	501,069	1,230,517	46.17	26,652

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
2004	2,011,876.22	592,296	557,374	1,454,502	46.73	31,126
2005	2,722,317.04	765,516	720,381	2,001,936	47.29	42,333
2006	1,310,462.37	350,942	330,250	980,212	47.86	20,481
2007	913,621.13	230,598	217,002	696,619	48.86	14,257
2008	2,761,680.30	659,213	620,345	2,141,335	49.44	43,312
2009	546,565.70	122,868	115,624	430,942	50.01	8,617
2010	2,402,470.22	505,960	476,128	1,926,342	50.60	38,070
2011	1,322,798.70	259,533	244,231	1,078,568	51.20	21,066
2012	2,644,891.82	480,577	452,242	2,192,650	51.79	42,337
2013	4,757,126.13	794,440	747,599	4,009,527	52.39	76,532
2014	15,716,180.18	2,388,859	2,248,010	13,468,170	53.00	254,116
2015	16,755,714.82	2,292,182	2,157,033	14,598,682	53.61	272,313
2016	11,972,728.13	1,463,067	1,376,803	10,595,925	53.85	196,767
2017	7,146,721.43	761,841	716,922	6,429,799	54.48	118,021
2018	61,114,949.08	5,579,795	5,250,806	55,864,143	54.74	1,020,536
2019	7,633,928.00	574,071	540,223	7,093,705	55.38	128,091
2020	8,961,533.75	533,211	501,772	8,459,761	55.32	152,924
2021	2,992,045.28	128,658	121,072	2,870,973	55.64	51,599
2022	2,280,055.72	60,649	57,073	2,222,983	54.99	40,425
2023	2,419,084.48	22,739	21,398	2,397,686	52.97	45,265
	264,297,644.80	71,801,849	67,568,355	196,729,290		4,214,076
CPG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1903	537.85	508	538			
1904	276.53	260	277			
1905	16.92	16	17			
1906	174.56	163	175			
1908	16.84	16	17			
1909	59.05	55	59			
1910	471.96	435	472			
1911	4.14	4	4			
1912	75.14	69	75			
1913	936.78	856	937			
1915	257.65	234	258			
1916	85.04	77	85			
1918	99.53	89	100			
1919	145.68	130	146			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1921	54.99	49	55			
1923	9,478.53	8,365	9,391	88	8.58	10
1924	1,055.81	928	1,042	14	8.81	2
1925	6,257.36	5,482	6,154	103	9.05	11
1926	4,562.61	3,981	4,469	93	9.30	10
1927	8,158.53	7,092	7,962	197	9.54	21
1928	26,099.30	22,599	25,370	729	9.79	74
1929	89.75	77	86	3	10.05	
1930	196.70	169	190	7	10.31	1
1931	5.84	5	6			
1932	56,106.89	47,776	53,635	2,472	10.84	228
1933	178.27	151	170	9	11.12	1
1934	13.01	11	12	1	11.40	
1935	88.20	74	83	5	11.69	
1936	600.03	501	562	38	11.99	3
1937	1.18	1	1			
1938	76.84	64	72	5	12.61	
1939	362.71	298	335	28	12.94	2
1940	514.23	421	473	42	13.27	3
1941	419.65	341	383	37	13.61	3
1942	979.04	792	889	90	13.97	6
1944	529.80	423	475	55	14.71	4
1945	859.41	682	766	94	15.10	6
1946	4,393.14	3,460	3,884	509	15.50	33
1947	4,370.17	3,418	3,837	533	15.91	34
1948	2,289.31	1,777	1,995	294	16.33	18
1949	66,657.64	51,344	57,641	9,017	16.77	538
1950	1,037.24	793	890	147	17.22	9
1951	20,193.17	15,305	17,182	3,011	17.67	170
1952	5,365.31	4,032	4,526	839	18.14	46
1953	32,064.91	23,882	26,811	5,254	18.63	282
1954	25,707.43	18,974	21,301	4,407	19.12	230
1955	8,825.84	6,453	7,244	1,581	19.63	81
1956	38,330.70	27,750	31,153	7,178	20.15	356
1957	51,924.19	37,215	41,779	10,145	20.68	491
1958	23,021.06	16,329	18,332	4,690	21.22	221
1959	63,689.33	44,696	50,177	13,512	21.77	621
1960	64,016.43	44,434	49,883	14,133	22.33	633
1961	153,562.79	105,369	118,291	35,272	22.91	1,540
1962	215,686.68	146,283	164,223	51,464	23.49	2,191
1963	472,985.58	316,900	355,763	117,222	24.09	4,866
1964	552,233.75	365,457	410,275	141,959	24.69	5,750

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1965	344,808.73	225,260	252,885	91,924	25.31	3,632
1966	749,961.97	483,568	542,871	207,091	25.93	7,987
1967	411,024.30	261,477	293,543	117,481	26.56	4,423
1968	543,244.56	340,756	382,545	160,700	27.21	5,906
1969	464,043.19	286,946	322,136	141,907	27.86	5,094
1970	355,085.64	216,361	242,895	112,191	28.52	3,934
1971	284,395.41	170,677	191,608	92,787	29.19	3,179
1972	158,486.13	93,637	105,120	53,366	29.87	1,787
1973	327,766.71	190,600	213,974	113,792	30.55	3,725
1974	326,696.11	186,887	209,806	116,890	31.24	3,742
1975	118,873.29	66,846	75,044	43,830	31.95	1,372
1976	263,679.27	145,746	163,620	100,060	32.65	3,065
1977	117,490.98	63,784	71,606	45,885	33.37	1,375
1978	357,322.71	190,410	213,761	143,562	34.10	4,210
1979	163,224.20	85,347	95,814	67,411	34.83	1,935
1980	225,839.03	115,828	130,033	95,806	35.56	2,694
1981	259,154.68	130,251	146,224	112,930	36.31	3,110
1982	244,782.89	137,127	153,944	90,839	32.58	2,788
1983	355,387.31	195,747	219,753	135,635	33.03	4,106
1984	139,279.20	75,378	84,622	54,657	33.49	1,632
1985	405,092.02	213,646	239,847	165,245	34.50	4,790
1986	651,939.11	337,378	378,753	273,186	34.96	7,814
1987	152,456.80	77,357	86,844	65,613	35.44	1,851
1988	173,705.61	85,706	96,217	77,489	36.45	2,126
1989	395,185.76	190,875	214,283	180,903	36.93	4,899
1990	89,167.77	42,123	47,289	41,879	37.42	1,119
1991	536,158.04	245,668	275,796	260,362	38.43	6,775
1992	1,307,909.48	585,028	656,773	651,136	38.92	16,730
1993	701,198.53	305,863	343,373	357,826	39.43	9,075
1995	2,000.33	821	922	1,079	40.94	26
1996	514,529.92	205,195	230,359	284,171	41.46	6,854
1997	770,623.49	298,154	334,718	435,905	41.99	10,381
1998	1,033,235.95	384,674	431,849	601,387	42.99	13,989
1999	388,998.54	140,117	157,300	231,698	43.52	5,324
2000	3,612,092.80	1,256,286	1,410,352	2,201,741	44.07	49,960
2001	449,328.99	150,615	169,086	280,243	44.62	6,281
2002	1,550,227.74	496,693	557,605	992,622	45.61	21,763
2003	356,662.35	109,674	123,124	233,538	46.17	5,058
2004	4,257,220.98	1,253,326	1,407,029	2,850,192	46.73	60,993
2005	6,357,779.16	1,787,807	2,007,056	4,350,723	47.29	92,001
2006	2,593,910.34	694,649	779,838	1,814,072	47.86	37,904
2007	1,044,736.13	263,691	296,029	748,707	48.86	15,324

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
2008	168,411.33	40,200	45,130	123,281	49.44	2,494
2009	3,189,141.82	716,919	804,839	2,384,303	50.01	47,677
2010	953,099.47	200,723	225,339	727,761	50.60	14,383
2011	2,262,343.17	443,872	498,307	1,764,036	51.20	34,454
2012	504,552.64	91,677	102,920	401,633	51.79	7,755
2013	946,022.31	157,986	177,361	768,662	52.39	14,672
2014	488,525.80	74,256	83,362	405,163	53.00	7,645
2015	2,365,587.02	323,612	363,298	2,002,289	53.61	37,349
2016	9,563,049.43	1,168,605	1,311,918	8,251,131	53.85	153,224
2017	7,608,489.50	811,065	910,531	6,697,959	54.48	122,943
2018	5,199,496.45	474,714	532,931	4,666,565	54.74	85,250
2019	4,081,106.12	306,899	344,536	3,736,570	55.38	67,471
2020	10,219,088.90	608,036	682,603	9,536,486	55.32	172,388
2021	69,933.38	3,007	3,376	66,558	55.64	1,196
2022	687,673.27	18,292	20,535	667,138	54.99	12,132
2023	689,237.90	6,479	7,274	681,964	52.97	12,875
	84,476,665.68	19,571,386	21,971,431	62,505,235		1,263,136
	646,013,546.81	191,449,358	196,479,099	449,534,448		9,755,688

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.1   1.51

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

UGI-GAS
INTERIM SURVIVOR CURVE.. IOWA 65-R1
PROBABLE RETIREMENT YEAR.. 9-2027
NET SALVAGE PERCENT.. 0

1924	2,407.94	2,277	454-	2,862	3.48	822
1925	7,870.11	7,440	1,485-	9,355	3.50	2,673
1926	25,880.25	24,455	4,880-	30,760	3.52	8,739
1927	21,525.65	20,334	4,057-	25,583	3.53	7,247
1928	20,073.10	18,954	3,782-	23,855	3.55	6,720
1929	38,576.53	36,408	7,265-	45,841	3.57	12,841
1930	18,316.52	17,282	3,448-	21,765	3.58	6,080
1931	3,541.51	3,340	666-	4,208	3.59	1,172
1932	2,599.37	2,451	489-	3,088	3.61	855
1933	132.25	125	25-	157	3.62	43
1934	397.48	374	75-	472	3.63	130
1935	3,151.03	2,967	592-	3,743	3.64	1,028
1936	5,329.48	5,016	1,001-	6,330	3.66	1,730
1937	2,936.25	2,763	551-	3,488	3.67	950
1938	2,630.45	2,474	494-	3,124	3.68	849
1939	10,293.46	9,676	1,931-	12,224	3.69	3,313
1940	6,418.22	6,031	1,203-	7,622	3.70	2,060
1941	15,336.85	14,404	2,874-	18,211	3.71	4,909
1942	552.65	519	104-	656	3.71	177
1943	1,040.34	976	195-	1,235	3.72	332
1944	3,036.62	2,848	568-	3,605	3.73	966
1945	344.24	323	64-	409	3.74	109
1946	8,491.13	7,956	1,588-	10,079	3.75	2,688
1947	15,680.55	14,687	2,931-	18,611	3.75	4,963
1948	28,343.36	26,531	5,294-	33,637	3.76	8,946
1949	18,843.62	17,628	3,517-	22,361	3.77	5,931
1950	42,323.97	39,569	7,896-	50,220	3.78	13,286
1951	42,390.17	39,612	7,904-	50,294	3.78	13,305
1952	56,111.01	52,398	10,455-	66,566	3.79	17,564
1953	86,647.88	80,874	16,138-	102,785	3.79	27,120
1954	50,904.22	47,477	9,474-	60,378	3.80	15,889
1955	64,396.93	60,017	11,976-	76,373	3.81	20,045
1956	75,873.77	70,672	14,102-	89,976	3.81	23,616
1957	81,508.12	75,858	15,137-	96,645	3.82	25,300
1958	65,896.58	61,290	12,230-	78,126	3.82	20,452
1959	72,899.42	67,743	13,517-	86,417	3.83	22,563
1960	5,816.72	5,402	1,078-	6,895	3.83	1,800
1961	49.12	46	9-	58	3.84	15
1962	3,362.94	3,118	622-	3,985	3.84	1,038
1968	296.92	274	55-	352	3.87	91
2012	5,956.16	4,431	884-	6,840	3.96	1,727

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
2015	124.01	85	17-	141	3.95	36
2016	9,466.46	6,205	1,238-	10,705	3.94	2,717
2019	390,885.34	208,264	41,557-	432,442	3.95	109,479
2020	62,669.40	29,480	5,882-	68,552	3.94	17,399
	1,381,328.10	1,101,054	219,704-	1,601,032		419,715
PNG						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1943	420.00	394	132	288	3.72	77
1952	77,260.07	72,148	24,136	53,124	3.79	14,017
	77,680.07	72,542	24,268	53,412		14,094
	1,459,008.17	1,173,596	195,436-	1,654,444		433,809

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.8   29.73

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1972	16,606.57	11,045	10,818	5,788	22.44	258
1973	44,043.19	28,851	28,259	15,785	23.11	683
1974	10,735.86	6,922	6,780	3,956	23.80	166
1975	43,111.35	27,347	26,786	16,326	24.50	666
1976	462,664.14	288,578	282,653	180,011	25.21	7,140
1977	422,149.81	258,833	253,519	168,631	25.92	6,506
1978	632,927.87	381,174	373,348	259,580	26.65	9,740
1979	504,605.05	298,317	292,192	212,413	27.39	7,755
1980	1,089,315.66	631,966	618,991	470,325	28.13	16,720
1981	1,361,204.28	774,267	758,370	602,834	28.89	20,867
1982	1,941,658.16	1,184,411	1,160,094	781,565	26.53	29,460
1983	2,315,156.21	1,387,705	1,359,214	955,942	27.07	35,314
1984	3,212,066.64	1,877,774	1,839,221	1,372,846	28.07	48,908
1985	3,359,695.96	1,927,122	1,887,556	1,472,140	28.62	51,437
1986	4,281,710.49	2,408,462	2,359,013	1,922,697	29.17	65,914
1987	7,409,943.72	4,056,944	3,973,650	3,436,294	30.17	113,898
1988	10,532,257.08	5,645,290	5,529,385	5,002,872	30.73	162,801
1989	12,913,534.20	6,771,857	6,632,823	6,280,711	31.29	200,726
1990	14,616,847.25	7,492,596	7,338,764	7,278,083	31.86	228,440
1991	8,830,834.04	4,390,691	4,300,545	4,530,289	32.86	137,866
1992	6,940,059.58	3,366,623	3,297,502	3,642,557	33.44	108,928
1993	5,147,597.51	2,433,784	2,383,816	2,763,782	34.01	81,264
1994	9,304,967.67	4,254,231	4,166,887	5,138,081	35.02	146,718
1995	15,048,311.05	6,690,479	6,553,116	8,495,196	35.60	238,629
1996	9,209,780.22	3,976,783	3,895,135	5,314,645	36.19	146,854
1997	13,939,648.21	5,798,894	5,679,836	8,259,812	37.20	222,038
1998	9,832,092.37	3,961,350	3,880,019	5,952,074	37.79	157,504
1999	10,408,607.68	4,029,172	3,946,448	6,462,159	38.79	166,593
2000	10,859,382.06	4,057,065	3,973,769	6,885,613	39.40	174,762
2001	10,965,986.37	3,947,755	3,866,703	7,099,283	40.00	177,482
2002	10,106,779.96	3,476,732	3,405,351	6,701,429	41.00	163,449
2003	14,245,375.49	4,700,974	4,604,457	9,640,918	41.61	231,697
2004	13,297,594.02	4,200,710	4,114,464	9,183,130	42.23	217,455
2005	14,284,822.10	4,281,161	4,193,264	10,091,558	43.23	233,439
2006	14,959,440.30	4,266,432	4,178,837	10,780,603	43.85	245,852
2007	14,114,904.19	3,796,909	3,718,954	10,395,950	44.85	231,794
2008	11,971,956.70	3,043,271	2,980,789	8,991,168	45.48	197,695
2009	11,531,414.24	2,742,170	2,685,870	8,845,544	46.48	190,309
2010	11,982,227.86	2,669,640	2,614,829	9,367,399	47.10	198,883
2011	16,795,952.09	3,485,160	3,413,606	13,382,347	47.74	280,317
2012	22,369,269.92	4,270,294	4,182,620	18,186,650	48.74	373,136
2013	30,020,480.90	5,265,592	5,157,483	24,862,998	49.38	503,503

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
2014	33,370,282.18	5,292,527	5,183,865	28,186,417	50.38	559,476
2015	31,691,166.69	4,525,499	4,432,585	27,258,582	51.02	534,272
2016	44,325,082.57	5,584,960	5,470,294	38,854,788	52.02	746,920
2017	39,781,862.42	4,368,048	4,278,367	35,503,496	52.67	674,074
2018	51,433,935.77	4,809,073	4,710,337	46,723,599	53.32	876,287
2019	73,598,214.19	5,667,062	5,550,710	68,047,504	53.98	1,260,606
2020	61,194,260.61	3,659,417	3,584,285	57,609,976	54.98	1,047,835
2021	54,967,278.69	2,363,593	2,315,066	52,652,213	55.64	946,301
2022	152,792,484.69	3,987,884	3,906,008	148,886,477	55.97	2,660,112
2023	147,487,176.83	1,297,887	1,271,240	146,215,937	56.00	2,610,999
	1,051,979,462.66	170,121,283	166,628,491	885,350,972		17,750,448
PNG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1973	337,953.03	221,383	234,240	103,713	23.11	4,488
1974	530,062.02	341,773	361,622	168,440	23.80	7,077
1975	1,494,251.48	947,849	1,002,896	491,355	24.50	20,055
1976	1,025,947.35	639,914	677,078	348,870	25.21	13,839
1977	1,270,491.28	778,976	824,216	446,275	25.92	17,217
1978	1,666,566.77	1,003,673	1,061,962	604,604	26.65	22,687
1979	1,842,397.13	1,089,207	1,152,464	689,933	27.39	25,189
1980	1,987,627.70	1,153,122	1,220,091	767,537	28.13	27,285
1981	1,467,267.94	834,597	883,067	584,201	28.89	20,222
1982	1,497,472.50	913,458	966,508	530,964	26.53	20,014
1983	778,935.51	466,894	494,009	284,926	27.07	10,526
1984	995,321.99	581,865	615,657	379,665	28.07	13,526
1985	1,257,530.37	721,319	763,210	494,320	28.62	17,272
1986	1,939,575.13	1,091,011	1,154,373	785,202	29.17	26,918
1987	3,162,650.58	1,731,551	1,832,113	1,330,538	30.17	44,101
1988	5,688,948.18	3,049,276	3,226,366	2,462,582	30.73	80,136
1989	4,242,924.20	2,224,989	2,354,208	1,888,717	31.29	60,362
1990	4,700,439.50	2,409,445	2,549,376	2,151,063	31.86	67,516
1991	2,214,611.04	1,101,105	1,165,053	1,049,558	32.86	31,940
1992	2,686,439.37	1,303,192	1,378,876	1,307,563	33.44	39,102
1993	2,615,614.79	1,236,663	1,308,484	1,307,131	34.01	38,434
1994	5,305,195.82	2,425,536	2,566,402	2,738,794	35.02	78,207
1995	5,590,985.87	2,485,752	2,630,115	2,960,871	35.60	83,171
1996	6,510,702.19	2,811,321	2,974,592	3,536,111	36.19	97,710

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1997	9,907,802.02	4,121,646	4,361,015	5,546,787	37.20	149,107
1998	7,417,221.54	2,988,399	3,161,954	4,255,268	37.79	112,603
1999	5,195,062.65	2,011,009	2,127,801	3,067,262	38.79	79,074
2000	4,042,299.59	1,510,203	1,597,910	2,444,390	39.40	62,040
2001	7,119,801.13	2,563,128	2,711,984	4,407,817	40.00	110,195
2002	3,201,300.34	1,101,247	1,165,203	2,036,097	41.00	49,661
2003	4,313,798.80	1,423,554	1,506,228	2,807,570	41.61	67,473
2004	8,700,212.09	2,748,397	2,908,013	5,792,199	42.23	137,158
2005	6,568,923.53	1,968,706	2,083,041	4,485,883	43.23	103,768
2006	3,964,942.82	1,130,802	1,196,475	2,768,468	43.85	63,135
2007	5,587,084.52	1,502,926	1,590,210	3,996,874	44.85	89,116
2008	4,638,028.47	1,178,987	1,247,458	3,390,570	45.48	74,551
2009	5,581,746.47	1,327,339	1,404,426	4,177,321	46.48	89,874
2010	4,085,865.47	910,331	963,199	3,122,666	47.10	66,299
2011	5,576,017.34	1,157,024	1,224,219	4,351,798	47.74	91,156
2012	8,970,783.39	1,712,523	1,811,980	7,158,804	48.74	146,877
2013	5,721,436.82	1,003,540	1,061,822	4,659,615	49.38	94,362
2014	8,088,862.81	1,282,894	1,357,399	6,731,463	50.38	133,614
2015	15,578,987.71	2,224,679	2,353,880	13,225,108	51.02	259,214
2016	18,055,676.93	2,275,015	2,407,139	15,648,538	52.02	300,818
2017	21,030,328.64	2,309,130	2,443,235	18,587,093	52.67	352,897
2018	22,657,900.26	2,118,514	2,241,549	20,416,351	53.32	382,902
2019	27,272,284.88	2,099,966	2,221,924	25,050,361	53.98	464,067
2020	17,344,005.45	1,037,172	1,097,407	16,246,599	54.98	295,500
2021	18,715,475.85	804,765	851,503	17,863,973	55.64	321,063
2022	38,715,376.85	1,010,471	1,069,155	37,646,222	55.97	672,614
2023	72,366,588.21	636,826	673,810	71,692,778	56.00	1,280,228
	421,227,726.32	77,723,064	82,236,917	338,990,809		6,916,360
CPG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1951	227.58	190	207	20	11.15	2
1967	7,196.51	5,132	5,595	1,601	19.22	83
1968	13,431.35	9,454	10,308	3,124	19.84	157
1969	11,165.00	7,754	8,454	2,711	20.47	132
1970	24,567.03	16,827	18,346	6,221	21.11	295
1971	349,534.11	235,960	257,263	92,272	21.77	4,238
1972	547,461.03	364,100	396,971	150,490	22.44	6,706

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 67-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1973	439,074.60	287,625	313,592	125,483	23.11	5,430
1974	620,997.69	400,407	436,556	184,442	23.80	7,750
1975	575,966.12	365,353	398,337	177,629	24.50	7,250
1976	353,925.25	220,754	240,684	113,241	25.21	4,492
1977	638,399.23	391,422	426,760	211,639	25.92	8,165
1978	532,207.55	320,517	349,453	182,754	26.65	6,858
1979	486,817.23	287,801	313,784	173,033	27.39	6,317
1980	725,558.59	420,933	458,935	266,624	28.13	9,478
1981	833,193.77	473,929	516,715	316,478	28.89	10,955
1982	751,252.59	458,264	499,636	251,616	26.53	9,484
1983	874,004.60	523,878	571,174	302,831	27.07	11,187
1984	1,395,068.80	815,557	889,186	505,883	28.07	18,022
1985	1,587,332.87	910,494	992,694	594,639	28.62	20,777
1986	1,877,717.81	1,056,216	1,151,572	726,146	29.17	24,894
1987	1,475,260.38	807,705	880,625	594,635	30.17	19,709
1988	2,106,766.32	1,129,227	1,231,174	875,592	30.73	28,493
1989	2,187,250.74	1,146,994	1,250,545	936,706	31.29	29,936
1990	2,298,067.48	1,177,989	1,284,338	1,013,729	31.86	31,818
1991	2,717,045.89	1,350,915	1,472,876	1,244,170	32.86	37,863
1992	2,172,106.05	1,053,689	1,148,816	1,023,290	33.44	30,601
1993	3,403,963.67	1,609,394	1,754,691	1,649,273	34.01	48,494
1994	3,476,725.33	1,589,559	1,733,065	1,743,660	35.02	49,790
1995	3,818,024.11	1,697,494	1,850,744	1,967,280	35.60	55,261
1996	4,748,500.35	2,050,402	2,235,513	2,512,987	36.19	69,439
1997	4,877,043.68	2,028,850	2,212,015	2,665,028	37.20	71,641
1998	5,685,605.47	2,290,730	2,497,538	3,188,067	37.79	84,363
1999	3,392,518.27	1,313,244	1,431,804	1,960,714	38.79	50,547
2000	4,941,877.32	1,846,285	2,012,968	2,928,909	39.40	74,338
2001	2,510,331.53	903,719	985,307	1,525,024	40.00	38,126
2002	4,172,881.28	1,435,471	1,565,066	2,607,815	41.00	63,605
2003	4,393,973.25	1,450,011	1,580,919	2,813,055	41.61	67,605
2004	4,613,388.01	1,457,369	1,588,941	3,024,447	42.23	71,618
2005	4,733,898.32	1,418,749	1,546,834	3,187,064	43.23	73,723
2006	6,343,861.17	1,809,269	1,972,611	4,371,251	43.85	99,686
2007	5,410,522.96	1,455,431	1,586,828	3,823,695	44.85	85,255
2008	4,915,164.61	1,249,435	1,362,234	3,552,930	45.48	78,121
2009	4,341,186.17	1,032,334	1,125,534	3,215,653	46.48	69,184
2010	6,220,238.63	1,385,869	1,510,986	4,709,253	47.10	99,984
2011	7,168,700.34	1,487,505	1,621,798	5,546,903	47.74	116,190
2012	5,184,448.63	989,711	1,079,062	4,105,386	48.74	84,230
2013	5,552,185.43	973,853	1,061,773	4,490,413	49.38	90,936
2014	7,527,632.03	1,193,882	1,301,666	6,225,966	50.38	123,580

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
2015	14,019,825.22	2,002,031	2,182,775	11,837,050	51.02	232,008
2016	12,515,364.13	1,576,936	1,719,302	10,796,062	52.02	207,537
2017	13,225,784.81	1,452,191	1,583,295	11,642,489	52.67	221,046
2018	16,657,561.01	1,557,482	1,698,092	14,959,469	53.32	280,560
2019	7,891,945.00	607,680	662,542	7,229,403	53.98	133,927
2020	4,706,823.91	281,468	306,879	4,399,945	54.98	80,028
2021	11,544,711.26	496,423	541,240	11,003,471	55.64	197,762
2022	29,739,820.39	776,209	846,285	28,893,535	55.97	516,233
2023	29,808,041.05	262,311	285,993	29,522,049	56.00	527,179
	273,144,143.51	55,920,383	60,968,897	212,175,247		4,403,088
	1,746,351,332.49	303,764,730	309,834,305	1,436,517,028		29,069,896

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 49.4 1.66

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1879	350.69	351	351			
1880	109.63	110	110			
1881	274.56	275	275			
1882	47.68	48	48			
1885	1.59	2	2			
1887	39.55	39	36	4	1.39	3
1888	169.62	165	152	18	1.72	10
1889	22.67	22	20	2	2.05	1
1890	145.73	141	129	16	2.39	7
1891	5.84	6	6			
1893	179.40	171	157	22	3.40	6
1894	0.93	1	1			
1895	51.95	49	45	7	4.05	2
1896	163.51	153	140	23	4.36	5
1897	57.76	54	50	8	4.66	2
1898	196.68	183	168	29	4.96	6
1899	964.01	892	819	145	5.26	28
1901	1,548.57	1,419	1,303	246	5.86	42
1902	733.56	669	614	119	6.15	19
1903	2,393.93	2,174	1,996	398	6.44	62
1904	5,932.60	5,362	4,924	1,009	6.73	150
1905	2,460.09	2,214	2,033	427	7.00	61
1906	4,050.73	3,630	3,333	718	7.27	99
1907	2,645.27	2,361	2,168	477	7.53	63
1908	5,708.75	5,073	4,658	1,051	7.79	135
1909	5,817.75	5,149	4,728	1,090	8.04	136
1910	8,010.35	7,062	6,485	1,526	8.28	184
1911	17,300.60	15,196	13,954	3,347	8.51	393
1912	11,196.02	9,796	8,995	2,201	8.75	252
1913	17,953.78	15,651	14,371	3,582	8.97	399
1914	47,288.87	41,073	37,715	9,574	9.19	1,042
1915	21,945.56	18,991	17,438	4,507	9.41	479
1916	17,842.44	15,386	14,128	3,714	9.62	386
1917	3,535.60	3,039	2,791	745	9.82	76
1918	3,745.14	3,208	2,946	799	10.02	80
1919	4,833.50	4,126	3,789	1,045	10.22	102
1920	2,133.53	1,815	1,667	467	10.41	45
1921	8,618.75	7,308	6,711	1,908	10.60	180

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1922	13,140.87	11,107	10,199	2,942	10.78	273
1923	13,722.53	11,564	10,619	3,104	10.95	283
1924	40,105.40	33,693	30,938	9,167	11.12	824
	265,445.99	229,728	211,009	54,437		5,835
PNG						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1904	1,028.33	929	730	299	6.73	44
1906	443.51	397	312	132	7.27	18
1911	656.65	577	453	203	8.51	24
1912	2,595.37	2,271	1,784	812	8.75	93
1914	307.00	267	210	97	9.19	11
1915	3,950.70	3,419	2,685	1,265	9.41	134
1916	110.37	95	75	36	9.62	4
1923	137.07	116	91	46	10.95	4
1924	16.03	13	10	6	11.12	1
1928	48.72	40	31	17	11.77	1
1939	119.81	96	75	44	13.23	3
1940	28.62	23	18	11	13.34	1
1943	23.96	19	15	9	13.67	1
	9,466.14	8,262	6,489	2,977		339
	274,912.13	237,990	217,498	57,414		6,174

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.3 2.25

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.7 REG AFUDC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	1,322,088.00	661,044	662,477	659,611	2.50	263,844
	1,322,088.00	661,044	662,477	659,611		263,844

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.5   19.96

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1978	10,010.63	5,887	5,251	4,760	19.36	246
1979	14,648.93	8,475	7,560	7,089	19.81	358
1980	56,146.80	31,932	28,483	27,664	20.27	1,365
1981	108,926.05	60,883	54,306	54,620	20.73	2,635
1982	112,255.32	77,793	69,390	42,865	18.38	2,332
1983	25,126.29	17,196	15,338	9,788	18.67	524
1984	59,802.62	40,391	36,028	23,775	18.98	1,253
1985	136,645.87	91,006	81,176	55,470	19.31	2,873
1986	152,694.10	100,198	89,375	63,319	19.65	3,222
1987	116,674.14	75,371	67,229	49,445	20.00	2,472
1988	125,535.21	79,765	71,149	54,386	20.37	2,670
1989	276,190.92	172,454	153,826	122,365	20.75	5,897
1990	114,576.35	70,235	62,648	51,928	21.15	2,455
1991	164,162.84	99,236	88,517	75,646	21.26	3,558
1992	242,595.94	143,665	128,146	114,450	21.69	5,277
1993	74,995.90	43,693	38,973	36,023	21.85	1,649
1994	158,498.70	90,249	80,500	77,998	22.31	3,496
1995	349,995.99	195,508	174,389	175,607	22.52	7,798
1996	809,410.55	440,724	393,117	416,293	23.01	18,092
1997	263,641.07	140,415	125,247	138,394	23.25	5,952
1998	453,770.10	236,051	210,553	243,217	23.52	10,341
1999	132,802.41	67,357	60,081	72,721	23.81	3,054
2000	589,132.67	290,737	259,332	329,801	24.12	13,673
2001	387,301.29	185,595	165,547	221,754	24.45	9,070
2002	239,952.77	111,962	99,868	140,085	24.58	5,699
2003	2,037,066.43	918,717	819,478	1,217,589	24.95	48,801
2004	1,120,239.60	489,321	436,465	683,775	25.14	27,199
2005	831,302.82	349,147	311,432	519,871	25.55	20,347
2006	811,641.28	328,065	292,628	519,014	25.79	20,125
2007	694,292.36	269,247	240,163	454,129	26.05	17,433
2008	1,402,165.26	519,362	463,261	938,905	26.34	35,646
2009	516,540.55	182,029	162,366	354,174	26.65	13,290
2010	553,840.01	185,426	165,396	388,444	26.82	14,483
2011	2,379,724.22	752,469	671,188	1,708,537	27.03	63,209
2012	2,326,360.10	690,231	615,673	1,710,688	27.26	62,755
2013	887,840.25	245,221	218,732	669,108	27.52	24,314
2014	1,457,576.34	371,099	331,013	1,126,563	27.81	40,509
2015	4,887,888.98	1,138,389	1,015,421	3,872,468	28.00	138,302
2016	3,557,236.66	747,020	666,327	2,890,909	28.21	102,478
2017	3,076,856.55	574,141	512,123	2,564,734	28.34	90,499
2018	1,710,218.02	276,542	246,670	1,463,548	28.51	51,335
2019	5,064,417.99	688,254	613,909	4,450,509	28.61	155,558

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
2020	2,473,634.00	268,389	239,398	2,234,236	28.76	77,686
2021	5,770,277.64	461,622	411,758	5,358,520	28.75	186,383
2022	24,380,951.35	1,206,857	1,076,493	23,304,459	28.80	809,183
2023	23,782,958.28	409,067	364,880	23,418,079	28.57	819,674
	94,898,522.15	13,947,393	12,440,801	82,457,721		2,935,170
PNG						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1957	2,198.59	1,709	1,557	641	10.46	61
1958	17,343.94	13,336	12,153	5,191	10.86	478
1959	6,147.89	4,674	4,259	1,889	11.27	168
1960	18,996.19	14,279	13,012	5,984	11.67	513
1961	15,485.19	11,505	10,484	5,001	12.08	414
1962	19,144.08	14,057	12,810	6,334	12.49	507
1963	42,256.72	30,659	27,939	14,318	12.90	1,110
1964	44,521.46	31,913	29,081	15,440	13.31	1,160
1965	90,339.71	63,949	58,275	32,065	13.73	2,335
1966	75,115.28	52,501	47,842	27,273	14.15	1,927
1967	90,037.62	62,126	56,613	33,424	14.57	2,294
1968	131,594.34	89,624	81,671	49,923	14.99	3,330
1969	353,889.94	237,860	216,754	137,136	15.41	8,899
1970	304,172.99	201,661	183,767	120,406	15.84	7,601
1971	152,335.58	99,602	90,764	61,571	16.27	3,784
1972	53,771.48	34,665	31,589	22,182	16.70	1,328
1973	140,210.52	89,079	81,175	59,036	17.14	3,444
1974	53,208.13	33,306	30,351	22,857	17.58	1,300
1975	24,960.62	15,391	14,025	10,935	18.02	607
1976	44,899.73	27,264	24,845	20,055	18.46	1,086
1977	191,719.02	114,583	104,416	87,303	18.91	4,617
1978	7,402.52	4,353	3,967	3,436	19.36	177
1979	25,753.70	14,899	13,577	12,177	19.81	615
1980	103,545.11	58,888	53,663	49,882	20.27	2,461
1981	417,211.58	233,196	212,504	204,707	20.73	9,875
1982	302,649.46	209,736	191,126	111,524	18.38	6,068
1983	207,264.86	141,852	129,265	78,000	18.67	4,178
1984	51,993.90	35,117	32,001	19,993	18.98	1,053
1985	96,935.94	64,559	58,831	38,105	19.31	1,973
1986	124,089.62	81,428	74,203	49,887	19.65	2,539

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

PNG
SURVIVOR CURVE.. IOWA 47-S0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1987	244,780.59	158,128	144,097	100,684	20.00	5,034
1988	112,330.74	71,375	65,042	47,289	20.37	2,322
1989	188,332.23	117,595	107,161	81,172	20.75	3,912
1990	100,129.04	61,379	55,933	44,196	21.15	2,090
1991	75,288.89	45,512	41,474	33,815	21.26	1,591
1992	139,697.17	82,729	75,388	64,309	21.69	2,965
1993	169,888.81	98,977	90,195	79,694	21.85	3,647
1994	404,187.94	230,145	209,724	194,464	22.31	8,716
1995	280,914.70	156,919	142,995	137,919	22.52	6,124
1996	189,221.91	103,031	93,889	95,333	23.01	4,143
1997	406,843.91	216,685	197,458	209,386	23.25	9,006
1998	429,094.84	223,215	203,409	225,686	23.52	9,595
1999	137,459.66	69,720	63,534	73,926	23.81	3,105
2000	125,711.19	62,038	56,533	69,178	24.12	2,868
2001	688,031.03	329,704	300,449	387,582	24.45	15,852
2002	105,403.55	49,181	44,817	60,586	24.58	2,465
2003	113,915.31	51,376	46,817	67,098	24.95	2,689
2004	477,425.37	208,539	190,035	287,390	25.14	11,432
2005	279,645.29	117,451	107,029	172,616	25.55	6,756
2006	243,832.19	98,557	89,812	154,020	25.79	5,972
2007	866,933.10	336,197	306,366	560,567	26.05	21,519
2008	774,429.81	286,849	261,396	513,033	26.34	19,477
2009	101,515.29	35,774	32,600	68,916	26.65	2,586
2010	88,947.03	29,779	27,137	61,810	26.82	2,305
2011	1,467,720.63	464,093	422,913	1,044,807	27.03	38,654
2012	443,323.90	131,534	119,863	323,461	27.26	11,866
2013	22,081.40	6,099	5,558	16,524	27.52	600
2014	3,052,892.91	777,267	708,299	2,344,594	27.81	84,308
2015	1,467,210.67	341,713	311,392	1,155,819	28.00	41,279
2016	1,178,201.51	247,422	225,468	952,734	28.21	33,773
2017	1,861,846.44	347,421	316,594	1,545,253	28.34	54,526
2018	10,764,230.27	1,740,576	1,586,131	9,178,099	28.51	321,926
2019	7,190,616.52	977,205	890,496	6,300,121	28.61	220,207
2020	4,531,332.49	491,650	448,025	4,083,308	28.76	141,979
2021	2,153,096.87	172,248	156,964	1,996,133	28.75	69,431
2022	11,867,107.46	587,422	535,299	11,331,809	28.80	393,466
2023	5,121,414.88	88,088	80,272	5,041,143	28.57	176,449
	61,074,231.25	11,701,364	10,663,080	50,411,151		1,820,537

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 47-S0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1965	120.42	85	86	35	13.73	3
1966	4,699.16	3,284	3,312	1,388	14.15	98
1967	5,488.05	3,787	3,819	1,669	14.57	115
1968	3,530.23	2,404	2,424	1,106	14.99	74
1969	6,220.62	4,181	4,216	2,005	15.41	130
1970	7,030.08	4,661	4,700	2,330	15.84	147
1971	5,396.60	3,528	3,558	1,839	16.27	113
1972	13,184.18	8,500	8,571	4,613	16.70	276
1973	12,009.89	7,630	7,694	4,316	17.14	252
1974	12,138.25	7,598	7,662	4,476	17.58	255
1975	31,506.03	19,427	19,590	11,916	18.02	661
1976	6,138.31	3,727	3,758	2,380	18.46	129
1977	19,497.12	11,653	11,751	7,746	18.91	410
1978	7,962.03	4,682	4,721	3,241	19.36	167
1979	32,665.78	18,897	19,056	13,610	19.81	687
1980	23,936.24	13,613	13,727	10,209	20.27	504
1981	31,771.70	17,758	17,907	13,865	20.73	669
1982	87,640.77	60,735	61,245	26,396	18.38	1,436
1983	73,875.60	50,560	50,984	22,891	18.67	1,226
1984	52,201.73	35,257	35,553	16,649	18.98	877
1985	43,781.13	29,158	29,403	14,378	19.31	745
1986	83,616.57	54,869	55,329	28,287	19.65	1,440
1987	75,260.18	48,618	49,026	26,234	20.00	1,312
1988	71,755.35	45,593	45,976	25,780	20.37	1,266
1989	65,135.06	40,670	41,011	24,124	20.75	1,163
1990	97,100.27	59,522	60,022	37,079	21.15	1,753
1991	68,651.00	41,500	41,848	26,803	21.26	1,261
1992	116,496.31	68,989	69,568	46,928	21.69	2,164
1993	127,351.57	74,195	74,818	52,534	21.85	2,404
1994	93,462.32	53,217	53,664	39,799	22.31	1,784
1995	119,732.13	66,882	67,443	52,289	22.52	2,322
1996	215,574.79	117,380	118,365	97,210	23.01	4,225
1997	162,649.05	86,627	87,354	75,295	23.25	3,238
1998	163,226.45	84,910	85,623	77,604	23.52	3,299
1999	252,058.10	127,844	128,917	123,141	23.81	5,172
2000	162,483.08	80,185	80,858	81,625	24.12	3,384
2001	433,328.46	207,651	209,394	223,935	24.45	9,159
2002	234,295.48	109,322	110,239	124,056	24.58	5,047
2003	282,320.08	127,326	128,395	153,926	24.95	6,169
2004	321,599.35	140,475	141,654	179,945	25.14	7,158
2005	212,997.46	89,459	90,210	122,788	25.55	4,806
2006	394,574.15	159,487	160,825	233,749	25.79	9,064

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 47-S0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2007	337,190.80	130,763	131,860	205,330	26.05	7,882
2008	444,482.99	164,636	166,018	278,465	26.34	10,572
2009	201,289.63	70,934	71,529	129,760	26.65	4,869
2010	257,803.59	86,313	87,037	170,766	26.82	6,367
2011	608,587.15	192,435	194,050	414,537	27.03	15,336
2012	422,956.05	125,491	126,544	296,412	27.26	10,874
2013	854,547.08	236,026	238,007	616,540	27.52	22,403
2014	388,233.75	98,844	99,674	288,560	27.81	10,376
2015	3,872,419.34	901,886	909,455	2,962,964	28.00	105,820
2016	968,206.50	203,323	205,029	763,177	28.21	27,053
2017	509,538.54	95,080	95,878	413,661	28.34	14,596
2018	472,369.92	76,382	77,023	395,347	28.51	13,867
2019	209,861.23	28,520	28,759	181,102	28.61	6,330
2020	1,646,334.92	178,627	180,126	1,466,209	28.76	50,981
2021	6,740,555.07	539,244	543,769	6,196,786	28.75	215,540
2022	5,924,315.41	293,254	295,715	5,628,600	28.80	195,438
2023	5,297,021.33	91,109	91,874	5,205,148	28.57	182,189
	33,390,174.43	5,708,713	5,756,622	27,633,552		987,057
	189,362,927.83	31,357,470	28,860,503	160,502,424		5,742,764

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.9   3.03

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

UGI-GAS
SURVIVOR CURVE.. IOWA 45-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1954	1,330.58	1,217	1,331			
1956	21,290.16	19,194	21,290			
1957	5,372.45	4,809	5,372			
1958	8,518.07	7,570	8,518			
1959	4,392.86	3,875	4,393			
1960	27,087.71	23,717	27,088			
1961	1,916.00	1,665	1,916			
1962	1,339.47	1,155	1,339			
1963	30.71	26	31			
1965	41,595.76	34,996	41,596			
1966	19,579.16	16,329	19,579			
1967	14,375.52	11,881	14,376			
1968	818.29	670	818			
1969	15,932.36	12,923	15,932			
1970	553.00	444	553			
1972	36,690.90	28,839	36,691			
1973	38,195.02	29,682	38,195			
1974	19,018.54	14,606	19,019			
1975	25,329.73	19,217	25,330			
1976	12,818.60	9,600	12,679	139	11.30	12
1977	148.01	109	144	4	11.75	
1978	4,242.67	3,092	4,084	159	12.21	13
1979	1,542.38	1,107	1,462	80	12.69	6
1980	4,638.03	3,280	4,332	306	13.18	23
1981	80,176.22	55,803	73,702	6,474	13.68	473
1982	141,945.62	108,390	141,946			
1983	6,800.47	5,123	6,769	32	13.26	2
1984	199,926.07	148,465	196,158	3,768	13.69	275
1985	433,461.53	317,077	418,934	14,527	14.13	1,028
1986	265,735.11	191,329	252,791	12,944	14.58	888
1987	791,585.85	560,522	740,583	51,002	15.05	3,389
1988	18,764.80	13,057	17,251	1,513	15.52	97
1989	37,807.02	25,826	34,122	3,685	16.01	230
1990	128,484.87	86,085	113,739	14,746	16.50	894
1991	257,739.07	169,206	223,562	34,178	17.00	2,010
1992	198,243.74	127,391	168,314	29,930	17.52	1,708
1993	32,985.36	20,725	27,383	5,603	18.04	311
1994	6,197.62	3,803	5,025	1,173	18.58	63
1995	265,285.40	158,773	209,777	55,508	19.12	2,903
1996	390,043.61	227,395	300,443	89,600	19.67	4,555
1998	8,401.63	4,628	6,115	2,287	20.80	110
2003	278,252.13	129,499	171,099	107,153	23.55	4,550

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2008	144,233.30	53,424	70,586	73,647	26.34	2,796
2009	23,277.53	8,133	10,746	12,532	27.00	464
2013	87,005.59	23,109	30,533	56,473	29.03	1,945
2014	78,923.32	19,194	25,360	53,563	29.56	1,812
2017	32,073.62	5,568	7,357	24,717	30.95	799
2019	90,422.23	11,267	14,886	75,536	31.60	2,390
2021	3,108,012.93	226,885	299,769	2,808,244	31.75	88,449
	7,412,540.62	2,950,680	3,873,017	3,539,524		122,195
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1960	16,780.37	14,692	13,314	3,466	5.60	619
1962	29,310.05	25,272	22,902	6,408	6.20	1,034
1963	28,716.91	24,562	22,258	6,459	6.51	992
1964	1,610.71	1,367	1,239	372	6.82	55
1965	15,335.53	12,902	11,692	3,644	7.14	510
1966	114,389.19	95,401	86,453	27,936	7.47	3,740
1967	4,284.76	3,541	3,209	1,076	7.81	138
1968	126,189.95	103,336	93,644	32,546	8.15	3,993
1969	116,466.84	94,467	85,606	30,860	8.50	3,631
1970	18,752.91	15,057	13,645	5,108	8.87	576
1971	13,464.24	10,700	9,696	3,768	9.24	408
1972	2,349.36	1,847	1,674	676	9.63	70
1974	21,308.55	16,365	14,830	6,479	10.44	621
1975	37,036.13	28,098	25,463	11,574	10.86	1,066
1977	2,043.72	1,510	1,368	675	11.75	57
1978	2,934.41	2,138	1,937	997	12.21	82
1979	1,353.24	972	881	472	12.69	37
1980	47,010.45	33,242	30,124	16,886	13.18	1,281
1981	702,199.80	488,731	442,891	259,309	13.68	18,955
1982	114,036.20	87,078	78,911	35,126	12.85	2,734
1983	6,538.51	4,925	4,463	2,075	13.26	156
1984	1,848.56	1,373	1,244	604	13.69	44
1985	33,053.50	24,179	21,911	11,142	14.13	789
1986	796.80	574	520	277	14.58	19
1987	900.93	638	578	323	15.05	21
1988	228,712.92	159,138	144,212	84,501	15.52	5,445
1989	5,767.35	3,940	3,570	2,197	16.01	137

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1990	8,208.45	5,500	4,984	3,224	16.50	195
1991	15,153.04	9,948	9,015	6,138	17.00	361
1992	1,292.66	831	753	540	17.52	31
1993	49,169.36	30,893	27,995	21,174	18.04	1,174
1994	82,378.57	50,547	45,806	36,573	18.58	1,968
1995	52,734.74	31,562	28,602	24,133	19.12	1,262
1996	44,580.63	25,991	23,553	21,027	19.67	1,069
1997	532,333.33	301,886	273,571	258,763	20.23	12,791
1998	118,063.23	65,029	58,930	59,134	20.80	2,843
1999	58,548.09	31,271	28,338	30,210	21.37	1,414
2000	69,703.96	36,037	32,657	37,047	21.95	1,688
2001	173,986.69	86,906	78,755	95,232	22.55	4,223
2002	184,888.86	89,449	81,059	103,830	22.94	4,526
2003	175,733.00	81,786	74,115	101,618	23.55	4,315
2004	75,956.41	33,922	30,740	45,216	24.17	1,871
2005	48,587.58	20,854	18,898	29,690	24.60	1,207
2006	162,733.73	66,639	60,389	102,345	25.24	4,055
2007	9,461.70	3,684	3,338	6,123	25.87	237
2008	460,995.77	170,753	154,737	306,259	26.34	11,627
2009	53,996.90	18,867	17,097	36,900	27.00	1,367
2010	265,809.52	87,558	79,346	186,464	27.48	6,785
2011	1,348,202.00	416,325	377,276	970,926	27.98	34,701
2012	500,205.13	143,809	130,320	369,885	28.50	12,978
2013	309,369.28	82,168	74,461	234,908	29.03	8,092
2014	8,711,938.63	2,118,743	1,920,016	6,791,923	29.56	229,767
2015	784,772.22	173,435	157,168	627,605	29.96	20,948
2018	1.37			1	31.26	
2020	1,817,684.99	179,951	163,073	1,654,612	31.84	51,966
2021	185,706.35	13,557	12,285	173,421	31.75	5,462
	17,995,388.08	5,633,946	5,105,511	12,889,877		476,133
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1955	266.15	242	229	37	4.14	9
1957	1,419.60	1,271	1,204	215	4.72	46
1959	1,154.96	1,019	965	190	5.30	36
1960	352.50	309	293	60	5.60	11
1961	3,229.10	2,806	2,658	571	5.90	97

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1966	2,958.56	2,467	2,337	621	7.47	83
1967	3,788.99	3,131	2,966	823	7.81	105
1968	2,785.64	2,281	2,161	625	8.15	77
1970	2,147.66	1,724	1,633	514	8.87	58
1972	481.68	379	359	123	9.63	13
1973	1,415.71	1,100	1,042	374	10.03	37
1974	1,983.52	1,523	1,443	541	10.44	52
1975	1,411.62	1,071	1,015	397	10.86	37
1977	3,626.30	2,679	2,538	1,088	11.75	93
1979	10,681.17	7,669	7,266	3,415	12.69	269
1981	703.40	490	464	239	13.68	17
1982	2,492.78	1,903	1,803	690	12.85	54
1988	1,548.80	1,078	1,021	527	15.52	34
1989	1,790.48	1,223	1,159	632	16.01	39
1992	417.27	268	254	163	17.52	9
1995	551.52	330	313	239	19.12	12
2012	1,055.35	303	287	768	28.50	27
2013	422.81	112	106	317	29.03	11
2019	181,294.79	22,589	21,401	159,894	31.60	5,060
	227,980.36	57,967	54,919	173,061		6,286
	25,635,909.06	8,642,593	9,033,447	16,602,462		604,614

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.5   2.36

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1923	1,103.30	1,103	1,103			
1924	1,158.18	1,158	1,158			
1925	1,658.20	1,658	1,658			
1926	1,793.36	1,793	1,793			
1927	3,296.83	3,297	3,297			
1928	2,475.75	2,476	2,476			
1929	4,442.73	4,443	4,443			
1930	4,035.22	4,035	4,035			
1931	2,530.35	2,530	2,530			
1932	749.36	746	731	18	0.18	18
1933	1,829.03	1,813	1,777	52	0.41	52
1934	1,433.86	1,413	1,385	49	0.66	49
1935	1,647.55	1,614	1,582	65	0.93	65
1936	2,675.96	2,606	2,555	121	1.20	101
1937	2,555.64	2,474	2,425	130	1.47	88
1938	2,387.07	2,297	2,252	135	1.74	78
1939	2,244.47	2,146	2,104	141	2.01	70
1940	2,516.92	2,392	2,345	172	2.28	75
1941	4,384.92	4,141	4,060	325	2.56	127
1942	1,708.56	1,603	1,572	137	2.84	48
1943	1,076.75	1,004	984	92	3.12	29
1944	1,777.55	1,646	1,614	164	3.41	48
1945	1,250.25	1,150	1,127	123	3.69	33
1946	2,900.29	2,649	2,597	303	3.98	76
1947	10,103.45	9,166	8,986	1,118	4.27	262
1948	10,711.46	9,650	9,460	1,251	4.56	274
1949	15,338.57	13,718	13,448	1,890	4.86	389
1950	17,297.43	15,357	15,055	2,242	5.16	434
1951	13,201.08	11,634	11,405	1,796	5.46	329
1952	15,882.59	13,894	13,621	2,262	5.76	393
1953	13,133.15	11,400	11,176	1,957	6.07	322
1954	22,304.22	19,211	18,834	3,471	6.38	544
1955	39,289.55	33,576	32,916	6,373	6.69	953
1956	69,828.43	59,187	58,024	11,804	7.01	1,684
1957	89,504.63	75,262	73,783	15,721	7.32	2,148
1958	121,717.75	101,476	99,482	22,236	7.65	2,907
1959	209,753.67	173,412	170,005	39,749	7.97	4,987
1960	285,845.97	234,271	229,668	56,178	8.30	6,768
1961	307,816.97	250,067	245,154	62,663	8.63	7,261
1962	294,847.15	237,352	232,688	62,159	8.97	6,930
1963	340,423.95	271,526	266,191	74,233	9.31	7,973
1964	335,123.71	264,821	259,618	75,506	9.65	7,824

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

UGI-GAS
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1965	448,657.92	351,124	344,225	104,433	10.00	10,443
1966	549,391.00	425,778	417,412	131,979	10.35	12,752
1967	520,850.30	399,581	391,730	129,120	10.71	12,056
1968	596,423.58	452,894	443,995	152,428	11.07	13,769
1969	621,847.64	467,194	458,015	163,833	11.44	14,321
1970	634,352.79	471,489	462,225	172,128	11.81	14,575
1971	700,919.88	515,176	505,054	195,866	12.19	16,068
1972	951,563.53	691,539	677,952	273,612	12.57	21,767
1973	1,226,816.81	881,173	863,860	362,957	12.96	28,006
1974	1,272,912.10	903,488	885,736	387,176	13.35	29,002
1975	883,220.06	619,217	607,051	276,170	13.75	20,085
1976	994,845.25	688,821	675,287	319,558	14.15	22,584
1977	1,891,744.77	1,292,970	1,267,566	624,179	14.56	42,869
1978	1,714,916.35	1,156,454	1,133,732	581,185	14.98	38,797
1979	3,095,910.48	2,059,462	2,018,997	1,076,913	15.40	69,929
1980	5,059,673.41	3,318,488	3,253,286	1,806,388	15.83	114,112
1981	5,162,337.29	3,336,419	3,270,865	1,891,473	16.27	116,255
1982	4,613,732.14	3,408,164	3,341,200	1,272,532	14.68	86,685
1983	3,362,109.81	2,450,978	2,402,821	959,289	15.06	63,698
1984	3,528,698.15	2,536,781	2,486,938	1,041,760	15.45	67,428
1985	4,017,857.35	2,846,250	2,790,326	1,227,531	15.85	77,447
1986	4,263,331.91	2,989,448	2,930,711	1,332,621	15.98	83,393
1987	5,003,537.47	3,451,440	3,383,626	1,619,912	16.41	98,715
1988	6,359,018.24	4,311,414	4,226,703	2,132,316	16.86	126,472
1989	8,986,775.59	5,983,395	5,865,832	3,120,943	17.32	180,193
1990	9,976,167.93	6,550,352	6,421,650	3,554,518	17.52	202,883
1991	9,002,433.81	5,793,066	5,679,243	3,323,191	18.01	184,519
1992	9,072,331.78	5,744,600	5,631,729	3,440,603	18.25	188,526
1993	5,885,913.01	3,644,557	3,572,948	2,312,965	18.76	123,292
1994	11,943,061.29	7,257,798	7,115,196	4,827,866	19.04	253,564
1995	12,773,910.08	7,572,374	7,423,591	5,350,319	19.58	273,254
1996	10,743,329.82	6,233,280	6,110,808	4,632,522	19.90	232,790
1997	11,708,261.55	6,608,143	6,478,305	5,229,956	20.45	255,744
1998	9,442,536.46	5,200,949	5,098,760	4,343,777	20.80	208,835
1999	9,553,455.23	5,126,384	5,025,660	4,527,795	21.16	213,979
2000	9,977,726.33	5,205,380	5,103,104	4,874,622	21.55	226,201
2001	9,929,714.91	5,004,576	4,906,245	5,023,470	22.14	226,896
2002	10,403,830.94	5,077,069	4,977,314	5,426,517	22.56	240,537
2003	8,891,358.60	4,192,276	4,109,906	4,781,453	22.98	208,070
2004	11,224,584.41	5,100,451	5,000,237	6,224,348	23.42	265,771
2005	9,659,288.03	4,217,245	4,134,384	5,524,904	23.87	231,458
2006	10,331,001.07	4,320,425	4,235,537	6,095,464	24.34	250,430

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2007	10,232,983.97	4,068,634	3,988,693	6,244,291	25.00	249,772
2008	13,441,489.00	5,083,571	4,983,688	8,457,801	25.48	331,939
2009	13,786,396.07	4,938,287	4,841,259	8,945,137	25.98	344,309
2010	14,118,986.63	4,765,158	4,671,531	9,447,455	26.50	356,508
2011	21,645,645.25	6,844,353	6,709,874	14,935,771	27.03	552,563
2012	31,698,080.13	9,331,915	9,148,560	22,549,520	27.56	818,197
2013	41,220,332.51	11,166,588	10,947,185	30,273,147	28.26	1,071,237
2014	40,111,028.48	9,947,535	9,752,084	30,358,944	28.81	1,053,764
2015	41,788,830.97	9,343,983	9,160,391	32,628,440	29.52	1,105,299
2016	45,536,957.25	9,084,623	8,906,127	36,630,830	30.09	1,217,376
2017	43,152,583.21	7,517,180	7,369,481	35,783,102	30.81	1,161,412
2018	49,241,392.82	7,312,347	7,168,673	42,072,720	31.54	1,333,948
2019	66,669,315.62	8,160,324	7,999,989	58,669,327	32.26	1,818,640
2020	75,772,653.26	7,266,597	7,123,822	68,648,831	33.00	2,080,268
2021	85,974,082.59	5,915,017	5,798,798	80,175,285	33.86	2,367,847
2022	43,596,215.37	1,804,883	1,769,420	41,826,795	34.73	1,204,342
2023	44,711,082.97	617,013	604,890	44,106,193	35.60	1,238,938
	921,944,161.00	253,883,237	248,895,343	673,048,818		23,527,868
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1917	886.27	886	886			
1918	404.61	405	405			
1919	1,803.39	1,803	1,803			
1920	2,328.17	2,328	2,328			
1921	2,254.48	2,254	2,254			
1922	6,431.03	6,431	6,431			
1923	7,946.49	7,946	7,946			
1924	14,242.95	14,243	14,243			
1925	17,357.70	17,358	17,358			
1926	13,231.04	13,231	13,231			
1927	11,676.52	11,677	11,677			
1928	10,727.29	10,727	10,727			
1929	10,271.99	10,272	10,272			
1930	10,405.36	10,405	10,405			
1931	10,365.58	10,366	10,366			
1932	8,537.64	8,504	8,538			
1933	5,368.11	5,320	5,368			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1934	7,080.41	6,979	7,080			
1935	5,458.43	5,348	5,458			
1936	7,682.84	7,482	7,683			
1937	8,321.05	8,055	8,321			
1938	6,514.88	6,268	6,515			
1939	10,459.71	10,003	10,460			
1940	9,440.81	8,973	9,441			
1941	8,572.44	8,095	8,572			
1942	5,202.99	4,882	5,203			
1943	3,697.46	3,447	3,687	10	3.12	3
1944	5,975.51	5,533	5,919	57	3.41	17
1945	9,786.81	9,002	9,629	158	3.69	43
1946	16,534.50	15,104	16,156	378	3.98	95
1947	17,674.92	16,034	17,151	524	4.27	123
1948	21,442.36	19,317	20,663	779	4.56	171
1949	19,205.61	17,177	18,374	832	4.86	171
1950	27,345.20	24,278	25,970	1,376	5.16	267
1951	20,698.79	18,242	19,513	1,186	5.46	217
1952	420,184.63	367,569	393,181	27,004	5.76	4,688
1953	16,272.94	14,126	15,110	1,163	6.07	192
1954	23,239.87	20,017	21,412	1,828	6.38	287
1955	39,339.69	33,619	35,962	3,378	6.69	505
1956	45,631.11	38,677	41,372	4,259	7.01	608
1957	63,408.41	53,318	57,033	6,375	7.32	871
1958	93,161.70	77,669	83,081	10,081	7.65	1,318
1959	148,387.82	122,678	131,226	17,162	7.97	2,153
1960	130,205.12	106,712	114,148	16,058	8.30	1,935
1961	157,686.84	128,103	137,029	20,658	8.63	2,394
1962	285,644.63	229,944	245,966	39,678	8.97	4,423
1963	360,005.75	287,144	307,152	52,854	9.31	5,677
1964	489,843.30	387,084	414,056	75,788	9.65	7,854
1965	586,592.36	459,073	491,061	95,531	10.00	9,553
1966	651,815.62	505,157	540,356	111,460	10.35	10,769
1967	766,442.94	587,992	628,963	137,480	10.71	12,837
1968	984,980.52	747,945	800,061	184,919	11.07	16,705
1969	1,043,834.40	784,233	838,878	204,957	11.44	17,916
1970	1,206,438.23	896,697	959,178	247,260	11.81	20,936
1971	425,795.66	312,960	334,767	91,029	12.19	7,468
1972	969,450.28	704,538	753,630	215,821	12.57	17,170
1973	1,248,295.93	896,601	959,076	289,220	12.96	22,316
1974	1,284,932.17	912,019	975,568	309,364	13.35	23,173
1975	1,097,079.13	769,151	822,745	274,334	13.75	19,952

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

PNG
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1976	1,328,765.49	920,024	984,131	344,635	14.15	24,356
1977	1,693,461.80	1,157,447	1,238,097	455,365	14.56	31,275
1978	1,289,219.09	869,385	929,963	359,256	14.98	23,982
1979	1,809,523.99	1,203,732	1,287,607	521,917	15.40	33,891
1980	2,391,959.05	1,568,814	1,678,128	713,831	15.83	45,094
1981	2,096,568.94	1,355,013	1,449,429	647,140	16.27	39,775
1982	1,736,219.32	1,282,545	1,371,912	364,307	14.68	24,817
1983	1,254,124.16	914,257	977,962	276,162	15.06	18,337
1984	1,765,768.67	1,269,411	1,357,863	407,906	15.45	26,402
1985	2,084,101.17	1,476,377	1,579,250	504,851	15.85	31,852
1986	2,644,529.35	1,854,344	1,983,553	660,976	15.98	41,363
1987	3,579,931.20	2,469,437	2,641,506	938,426	16.41	57,186
1988	4,748,240.99	3,219,307	3,443,626	1,304,615	16.86	77,379
1989	4,483,891.27	2,985,375	3,193,394	1,290,497	17.32	74,509
1990	4,926,056.31	3,234,449	3,459,823	1,466,233	17.52	83,689
1991	3,592,012.44	2,311,460	2,472,521	1,119,492	18.01	62,159
1992	4,357,242.15	2,759,006	2,951,252	1,405,991	18.25	77,041
1993	4,635,676.17	2,870,411	3,070,419	1,565,257	18.76	83,436
1994	4,698,020.71	2,854,987	3,053,921	1,644,100	19.04	86,350
1995	5,316,306.54	3,151,507	3,371,102	1,945,205	19.58	99,347
1996	5,404,003.68	3,135,403	3,353,876	2,050,128	19.90	103,022
1997	6,265,647.49	3,536,331	3,782,740	2,482,907	20.45	121,414
1998	5,836,337.04	3,214,654	3,438,649	2,397,688	20.80	115,273
1999	4,211,885.05	2,260,098	2,417,580	1,794,305	21.16	84,797
2000	3,507,468.86	1,829,847	1,957,349	1,550,119	21.55	71,931
2001	6,130,136.58	3,089,589	3,304,869	2,825,267	22.14	127,609
2002	5,041,753.14	2,460,376	2,631,813	2,409,940	22.56	106,824
2003	5,716,661.56	2,695,406	2,883,220	2,833,442	22.98	123,300
2004	11,727,165.66	5,328,824	5,700,133	6,027,033	23.42	257,346
2005	7,606,720.63	3,321,094	3,552,506	4,054,215	23.87	169,846
2006	4,617,545.67	1,931,058	2,065,613	2,551,933	24.34	104,845
2007	6,168,615.93	2,452,642	2,623,540	3,545,076	25.00	141,803
2008	6,630,997.51	2,507,843	2,682,588	3,948,410	25.48	154,961
2009	6,802,090.53	2,436,509	2,606,283	4,195,807	25.98	161,501
2010	4,431,917.21	1,495,772	1,599,996	2,831,921	26.50	106,865
2011	7,622,799.77	2,410,329	2,578,279	5,044,521	27.03	186,627
2012	9,598,822.14	2,825,893	3,022,799	6,576,023	27.56	238,608
2013	9,489,837.23	2,570,797	2,749,928	6,739,909	28.26	238,496
2014	10,250,637.15	2,542,158	2,719,294	7,531,343	28.81	261,414
2015	14,804,213.97	3,310,222	3,540,876	11,263,338	29.52	381,549
2016	15,752,645.84	3,142,653	3,361,631	12,391,015	30.09	411,798
2017	17,400,512.10	3,031,169	3,242,379	14,158,133	30.81	459,530

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2018	19,757,974.91	2,934,059	3,138,502	16,619,473	31.54	526,933
2019	26,615,654.51	3,257,756	3,484,754	23,130,900	32.26	717,015
2020	25,413,871.59	2,437,190	2,607,012	22,806,860	33.00	691,117
2021	29,519,765.16	2,030,960	2,172,476	27,347,289	33.86	807,658
2022	21,454,972.06	888,236	950,128	20,504,844	34.73	590,407
2023	21,471,262.14	296,303	316,949	21,154,313	35.60	594,222
	392,567,536.31	122,871,860	131,422,265	261,145,271		9,311,758
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1931	162.36	162	162			
1935	28.92	28	29			
1941	43.75	41	44			
1942	28.62	27	29			
1946	270.86	247	267	3	3.98	1
1947	108.68	99	107	1	4.27	
1948	3.61	3	3			
1949	192.30	172	186	6	4.86	1
1951	57.58	51	55	2	5.46	
1952	39.63	35	38	2	5.76	
1953	65.62	57	62	4	6.07	1
1954	400.06	345	374	26	6.38	4
1955	1,147.00	980	1,061	86	6.69	13
1956	821.48	696	754	68	7.01	10
1958	2,840.54	2,368	2,564	276	7.65	36
1959	1,062.21	878	951	111	7.97	14
1960	187.97	154	167	21	8.30	3
1961	19,147.87	15,556	16,846	2,302	8.63	267
1962	8,366.95	6,735	7,293	1,074	8.97	120
1963	15,674.01	12,502	13,539	2,135	9.31	229
1964	17,158.25	13,559	14,683	2,475	9.65	256
1965	15,043.34	11,773	12,749	2,294	10.00	229
1966	14,484.51	11,225	12,156	2,329	10.35	225
1967	26,300.64	20,177	21,850	4,451	10.71	416
1968	30,075.71	22,838	24,732	5,344	11.07	483
1969	26,381.45	19,820	21,463	4,918	11.44	430
1970	29,144.02	21,662	23,458	5,686	11.81	481
1971	54,928.61	40,373	43,721	11,208	12.19	919

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1972	71,716.55	52,119	56,441	15,276	12.57	1,215
1973	43,568.91	31,294	33,889	9,680	12.96	747
1974	111,034.81	78,810	85,345	25,690	13.35	1,924
1975	148,630.29	104,203	112,843	35,787	13.75	2,603
1976	98,536.00	68,225	73,882	24,654	14.15	1,742
1977	51,343.41	35,092	38,002	13,342	14.56	916
1978	65,527.85	44,189	47,853	17,675	14.98	1,180
1979	58,372.78	38,831	42,051	16,322	15.40	1,060
1980	141,381.34	92,728	100,417	40,965	15.83	2,588
1981	341,952.04	221,004	239,329	102,623	16.27	6,307
1982	332,606.62	245,697	266,069	66,537	14.68	4,532
1983	295,306.59	215,279	233,129	62,177	15.06	4,129
1984	392,671.06	282,291	305,698	86,973	15.45	5,629
1985	505,177.67	357,868	387,541	117,636	15.85	7,422
1986	580,998.35	407,396	441,176	139,822	15.98	8,750
1987	739,641.68	510,205	552,510	187,132	16.41	11,404
1988	716,399.49	485,719	525,993	190,406	16.86	11,293
1989	1,248,681.33	831,372	900,307	348,375	17.32	20,114
1990	1,273,730.12	836,331	905,677	368,053	17.52	21,008
1991	1,116,306.65	718,343	777,906	338,401	18.01	18,790
1992	1,732,854.46	1,097,243	1,188,223	544,631	18.25	29,843
1993	1,250,726.43	774,450	838,665	412,061	18.76	21,965
1994	2,223,903.56	1,351,466	1,463,525	760,378	19.04	39,936
1995	2,501,064.25	1,482,631	1,605,566	895,498	19.58	45,735
1996	2,414,245.45	1,400,745	1,516,890	897,355	19.90	45,093
1997	2,502,109.26	1,412,190	1,529,284	972,825	20.45	47,571
1998	2,798,997.57	1,541,688	1,669,520	1,129,478	20.80	54,302
1999	2,523,861.62	1,354,304	1,466,599	1,057,263	21.16	49,965
2000	2,255,991.73	1,176,951	1,274,540	981,452	21.55	45,543
2001	2,289,854.23	1,154,087	1,249,780	1,040,074	22.14	46,977
2002	3,489,962.01	1,703,101	1,844,317	1,645,645	22.56	72,945
2003	1,687,394.17	795,606	861,575	825,819	22.98	35,936
2004	2,571,775.50	1,168,615	1,265,513	1,306,263	23.42	55,776
2005	2,701,694.79	1,179,560	1,277,365	1,424,329	23.87	59,670
2006	1,849,781.31	773,579	837,722	1,012,060	24.34	41,580
2007	1,400,969.30	557,025	603,212	797,758	25.00	31,910
2008	4,049,582.90	1,531,552	1,658,544	2,391,039	25.48	93,840
2009	2,027,841.78	726,373	786,602	1,241,240	25.98	47,777
2010	3,084,042.94	1,040,864	1,127,169	1,956,874	26.50	73,844
2011	3,358,161.71	1,061,851	1,149,896	2,208,265	27.03	81,697
2012	5,994,494.10	1,764,779	1,911,109	4,083,385	27.56	148,163
2013	5,438,029.89	1,473,162	1,595,312	3,842,718	28.26	135,977

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2014	7,061,763.25	1,751,317	1,896,531	5,165,232	28.81	179,286
2015	6,854,814.94	1,532,737	1,659,827	5,194,988	29.52	175,982
2016	6,569,505.77	1,310,616	1,419,288	5,150,218	30.09	171,160
2017	5,282,441.01	920,201	996,501	4,285,940	30.81	139,109
2018	5,561,690.03	825,911	894,393	4,667,297	31.54	147,980
2019	6,776,168.64	829,403	898,175	5,877,994	32.26	182,207
2020	9,907,640.64	950,143	1,028,926	8,878,715	33.00	269,052
2021	7,317,296.61	503,430	545,173	6,772,124	33.86	200,004
2022	6,961,688.58	288,214	312,112	6,649,577	34.73	191,465
2023	6,818,312.80	94,093	101,895	6,716,418	35.60	188,663
	137,856,411.32	41,387,446	44,819,149	93,037,262		3,288,444
	1,452,368,108.63	418,142,543	425,136,757	1,027,231,351		36,128,070

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.4   2.49

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1951	278.21	278	278			
1952	1,594.13	1,594	1,594			
1953	1,809.20	1,809	1,809			
1954	823.85	824	824			
1955	1,727.13	1,727	1,727			
1956	2,081.92	2,082	2,082			
1957	1,870.60	1,871	1,871			
1958	2,858.64	2,859	2,859			
1959	5,859.72	5,835	5,750	109	0.15	109
1960	3,738.30	3,698	3,644	94	0.38	94
1961	4,947.00	4,857	4,786	161	0.64	161
1962	6,132.49	5,975	5,888	244	0.90	244
1963	6,481.37	6,265	6,174	307	1.17	262
1964	7,915.52	7,588	7,478	438	1.45	302
1965	8,313.90	7,905	7,790	524	1.72	305
1966	21,629.13	20,393	20,097	1,532	2.00	766
1967	45,221.10	42,262	41,648	3,573	2.29	1,560
1968	74,495.49	69,025	68,022	6,473	2.57	2,519
1969	72,775.52	66,829	65,858	6,918	2.86	2,419
1970	64,054.04	58,289	57,442	6,612	3.15	2,099
1971	41,843.64	37,731	37,183	4,661	3.44	1,355
1972	42,949.41	38,360	37,803	5,147	3.74	1,376
1973	70,209.99	62,126	61,223	8,987	4.03	2,230
1974	74,569.10	65,365	64,415	10,154	4.32	2,350
1975	57,293.92	49,731	49,008	8,285	4.62	1,793
1976	32,981.62	28,336	27,924	5,057	4.93	1,026
1977	40,229.61	34,207	33,710	6,520	5.24	1,244
1978	108,984.75	91,671	90,339	18,646	5.56	3,354
1979	123,218.32	102,518	101,028	22,190	5.88	3,774
1980	585,477.84	481,433	474,438	111,040	6.22	17,852
1981	334,488.76	271,702	267,754	66,734	6.57	10,157
1982	210,629.10	182,700	180,045	30,584	6.34	4,824
1983	25,769.18	22,022	21,702	4,067	6.89	590
1984	98,982.83	83,670	82,454	16,529	7.23	2,286
1985	323,593.11	270,330	266,402	57,191	7.59	7,535
1986	232,450.91	192,655	189,856	42,595	7.75	5,496
1987	379,649.87	310,402	305,892	73,758	8.14	9,061
1988	326,959.63	263,464	259,636	67,324	8.56	7,865
1989	513,534.02	407,489	401,568	111,966	8.98	12,468
1990	865,838.69	675,874	666,054	199,785	9.42	21,209
1991	857,066.97	657,370	647,819	209,248	9.87	21,200
1992	795,118.70	598,565	589,868	205,251	10.34	19,850

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1993	642,881.68	474,511	467,617	175,265	10.82	16,198
1994	929,599.79	674,611	664,809	264,791	11.15	23,748
1995	947,366.23	672,251	662,484	284,883	11.66	24,433
1996	660,749.36	457,899	451,246	209,503	12.18	17,201
1997	931,943.03	629,807	620,656	311,287	12.71	24,492
1998	783,203.68	517,228	509,713	273,491	13.11	20,861
1999	968,626.71	621,761	612,727	355,900	13.67	26,035
2000	868,766.35	541,068	533,207	335,560	14.23	23,581
2001	1,176,702.32	712,140	701,793	474,909	14.68	32,351
2002	836,988.12	489,471	482,359	354,629	15.26	23,239
2003	919,483.17	518,405	510,873	408,610	15.86	25,764
2004	854,446.49	464,819	458,065	396,381	16.34	24,258
2005	1,004,214.70	523,899	516,287	487,928	16.96	28,769
2006	1,164,040.15	582,602	574,137	589,903	17.47	33,767
2007	731,491.09	350,018	344,932	386,559	17.98	21,499
2008	2,933,436.45	1,332,367	1,313,008	1,620,428	18.63	86,979
2009	1,467,386.18	631,856	622,675	844,711	19.17	44,064
2010	1,673,328.57	680,041	670,160	1,003,168	19.72	50,871
2011	2,965,563.16	1,130,473	1,114,048	1,851,515	20.29	91,253
2012	2,532,379.55	902,793	889,676	1,642,704	20.76	79,128
2013	3,130,045.04	1,031,976	1,016,982	2,113,063	21.35	98,973
2014	3,208,956.50	972,314	958,187	2,250,770	21.85	103,010
2015	2,692,725.87	739,423	728,680	1,964,046	22.46	87,446
2016	3,336,774.16	823,516	811,551	2,525,223	22.89	110,320
2017	4,151,443.02	901,278	888,183	3,263,260	23.44	139,218
2018	7,743,983.37	1,452,771	1,431,663	6,312,320	23.82	265,001
2019	4,095,987.79	641,432	632,112	3,463,875	24.24	142,899
2020	4,609,296.05	574,318	565,973	4,043,323	24.59	164,430
2021	6,748,300.17	619,494	610,493	6,137,807	24.75	247,992
2022	4,442,197.07	254,982	251,277	4,190,920	24.61	170,293
2023	4,858,014.53	102,018	100,536	4,757,479	23.31	204,096
	80,486,767.58	26,261,228	25,879,854	54,606,914		2,621,904
PNG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1952	9,094.09	9,094	9,094			
1953	155.79	156	156			
1954	335.64	336	336			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1955	1,774.17	1,774	1,774			
1956	3,588.46	3,588	3,588			
1957	1,487.73	1,488	1,488			
1958	6,577.76	6,578	6,578			
1959	5,545.09	5,521	5,545			
1960	10,389.85	10,277	10,390			
1961	27,573.13	27,069	27,573			
1962	51,227.58	49,911	51,228			
1963	62,711.86	60,615	62,712			
1964	119,222.38	114,283	119,222			
1965	221,437.38	210,556	221,437			
1966	326,544.36	307,886	325,159	1,386	2.00	693
1967	257,178.00	240,351	253,835	3,343	2.29	1,460
1968	303,176.24	280,914	296,673	6,503	2.57	2,530
1969	454,747.91	417,590	441,017	13,731	2.86	4,801
1970	398,642.01	362,764	383,115	15,527	3.15	4,929
1971	253,106.59	228,229	241,033	12,074	3.44	3,510
1972	257,146.52	229,668	242,552	14,594	3.74	3,902
1973	111,992.35	99,098	104,657	7,335	4.03	1,820
1974	34,972.35	30,656	32,376	2,597	4.32	601
1975	59,337.99	51,505	54,394	4,944	4.62	1,070
1976	25,641.25	22,029	23,265	2,376	4.93	482
1977	42,385.23	36,040	38,062	4,323	5.24	825
1978	36,923.09	31,057	32,799	4,124	5.56	742
1979	118,487.62	98,582	104,112	14,375	5.88	2,445
1980	888,827.62	730,874	771,876	116,951	6.22	18,802
1981	1,321,232.89	1,073,224	1,133,432	187,801	6.57	28,585
1982	101,764.60	88,271	93,223	8,542	6.34	1,347
1983	61,682.25	52,714	55,671	6,011	6.89	872
1984	265,823.39	224,701	237,307	28,517	7.23	3,944
1985	506,874.24	423,443	447,198	59,676	7.59	7,862
1986	589,845.45	488,864	516,289	73,556	7.75	9,491
1987	594,499.58	486,063	513,331	81,168	8.14	9,971
1988	654,590.22	527,469	557,060	97,530	8.56	11,394
1989	641,156.97	508,758	537,300	103,857	8.98	11,565
1990	685,600.62	535,180	565,204	120,397	9.42	12,781
1991	868,067.11	665,807	703,159	164,908	9.87	16,708
1992	1,225,399.42	922,481	974,233	251,167	10.34	24,291
1993	1,363,526.41	1,006,419	1,062,880	300,647	10.82	27,786
1994	2,289,728.71	1,661,656	1,754,876	534,853	11.15	47,969
1995	485,280.76	344,355	363,673	121,607	11.66	10,429
1996	1,211,502.47	839,571	886,671	324,831	12.18	26,669

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1997	1,191,101.72	804,947	850,105	340,997	12.71	26,829
1998	1,514,147.19	999,943	1,056,040	458,107	13.11	34,943
1999	762,394.58	489,381	516,835	245,559	13.67	17,963
2000	831,021.09	517,560	546,595	284,426	14.23	19,988
2001	1,030,875.62	623,886	658,886	371,989	14.68	25,340
2002	1,031,793.18	603,393	637,244	394,550	15.26	25,855
2003	600,154.39	338,367	357,350	242,805	15.86	15,309
2004	1,830,250.59	995,656	1,051,513	778,738	16.34	47,658
2005	1,239,540.49	646,668	682,946	556,594	16.96	32,818
2006	1,301,727.79	651,515	688,065	613,662	17.47	35,127
2007	1,827,891.28	874,646	923,714	904,177	17.98	50,288
2008	1,421,770.78	645,768	681,996	739,775	18.63	39,709
2009	1,466,886.27	631,641	667,076	799,810	19.17	41,722
2010	990,416.59	402,505	425,086	565,331	19.72	28,668
2011	1,912,873.67	729,187	770,095	1,142,779	20.29	56,322
2012	1,403,345.68	500,293	528,360	874,986	20.76	42,148
2013	1,335,028.41	440,159	464,852	870,176	21.35	40,758
2014	1,609,625.08	487,716	515,077	1,094,548	21.85	50,094
2015	1,649,728.49	453,015	478,429	1,171,299	22.46	52,150
2016	1,318,993.92	325,528	343,790	975,204	22.89	42,604
2017	2,709,510.16	588,235	621,235	2,088,275	23.44	89,090
2018	4,281,438.12	803,198	848,258	3,433,180	23.82	144,130
2019	2,107,543.08	330,041	348,556	1,758,987	24.24	72,565
2020	3,913,784.09	487,657	515,015	3,398,769	24.59	138,218
2021	2,951,733.52	270,969	286,170	2,665,563	24.75	107,700
2022	4,664,298.82	267,731	282,751	4,381,548	24.61	178,039
2023	3,771,768.94	79,207	83,651	3,688,118	23.31	158,220
	67,626,448.67	28,506,277	30,097,247	37,529,202		1,914,531
CPG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1967	3,074.25	2,873	2,332	742	2.29	324
1968	7,148.39	6,623	5,376	1,772	2.57	689
1969	16,305.78	14,973	12,154	4,152	2.86	1,452
1970	13,351.03	12,149	9,862	3,489	3.15	1,108
1971	13,720.09	12,372	10,043	3,677	3.44	1,069
1972	36,682.90	32,763	26,595	10,088	3.74	2,697
1973	54,099.44	47,870	38,858	15,241	4.03	3,782

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1974	31,201.88	27,351	22,202	9,000	4.32	2,083
1975	34,816.16	30,220	24,531	10,285	4.62	2,226
1976	24,536.70	21,080	17,112	7,425	4.93	1,506
1977	13,749.83	11,691	9,490	4,260	5.24	813
1978	6,934.33	5,833	4,735	2,199	5.56	396
1979	15,554.11	12,941	10,505	5,049	5.88	859
1980	62,383.41	51,297	41,640	20,743	6.22	3,335
1981	27,520.55	22,355	18,147	9,374	6.57	1,427
1982	58,982.61	51,162	41,530	17,452	6.34	2,753
1983	54,010.42	46,157	37,468	16,543	6.89	2,401
1984	41,553.15	35,125	28,513	13,041	7.23	1,804
1985	55,356.41	46,245	37,539	17,817	7.59	2,347
1986	74,577.47	61,810	50,174	24,404	7.75	3,149
1987	58,806.95	48,081	39,029	19,777	8.14	2,430
1988	9,424.82	7,595	6,165	3,260	8.56	381
1989	25,110.43	19,925	16,174	8,936	8.98	995
1990	140,595.07	109,749	89,088	51,507	9.42	5,468
1991	158,291.69	121,410	98,554	59,738	9.87	6,052
1992	141,369.74	106,423	86,388	54,982	10.34	5,317
1993	78,477.33	57,924	47,019	31,458	10.82	2,907
1994	55,216.96	40,071	32,527	22,690	11.15	2,035
1996	22,252.43	15,421	12,518	9,735	12.18	799
1997	15,215.15	10,282	8,346	6,869	12.71	540
2001	3,976.65	2,407	1,954	2,023	14.68	138
2002	3,505.47	2,050	1,664	1,841	15.26	121
2003	13,948.40	7,864	6,384	7,565	15.86	477
2004	97,927.96	53,273	43,244	54,684	16.34	3,347
2005	43,546.42	22,718	18,441	25,105	16.96	1,480
2006	82,208.35	41,145	33,399	48,809	17.47	2,794
2007	43,235.32	20,688	16,793	26,442	17.98	1,471
2008	79,473.21	36,097	29,302	50,172	18.63	2,693
2009	718.22	309	251	467	19.17	24
2012	625,122.41	222,856	180,902	444,220	20.76	21,398
2013	1,161,143.76	382,829	310,759	850,385	21.35	39,831
2014	702,836.13	212,959	172,868	529,968	21.85	24,255
2015	619,336.11	170,070	138,053	481,283	22.46	21,428
2016	565,875.67	139,658	113,367	452,509	22.89	19,769
2017	921,846.24	200,133	162,457	759,389	23.44	32,397
2018	657,470.72	123,342	100,122	557,349	23.82	23,398
2019	1,210,524.26	189,568	153,881	1,056,644	24.24	43,591
2020	768,386.51	95,741	77,717	690,669	24.59	28,087

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
2021	814,734.45	74,793	60,713	754,022	24.75	30,466
2022	1,914,314.39	109,882	89,196	1,825,118	24.61	74,162
2023	1,238,270.63	26,004	21,109	1,217,162	23.31	52,216
	12,918,720.76	3,224,157	2,617,190	10,301,531		486,687
	161,031,937.01	57,991,662	58,594,291	102,437,647		5,023,122

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.4 3.12

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1995	225,308.19	220,892	225,308			
1996	173,108.40	168,988	173,108			
1997	173,127.78	167,449	173,128			
1998	184,130.59	177,023	184,131			
1999	342,667.80	326,562	342,668			
2000	478,162.92	450,621	478,163			
2001	549,785.70	513,390	549,786			
2002	670,198.61	616,717	661,976	8,223	1.86	4,421
2003	252,157.11	229,009	245,815	6,342	2.07	3,064
2004	243,716.21	217,663	233,636	10,080	2.33	4,326
2005	216,895.80	190,196	204,154	12,742	2.60	4,901
2006	5,390,842.80	4,622,648	4,961,887	428,956	2.91	147,408
2008	15,525.65	12,585	13,509	2,017	3.62	557
2018	303,687.22	105,076	112,787	190,900	10.40	18,356
2020	1,511,975.32	333,844	358,344	1,153,632	12.35	93,411
	10,731,290.10	8,352,663	8,918,398	1,812,892		276,444
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1999	68,566.40	65,344	68,566			
2000	110,387.90	104,030	110,388			
2001	719,557.21	671,923	719,557			
2002	1,586,309.09	1,459,722	1,586,309			
2003	887,157.53	805,716	883,300	3,858	2.07	1,864
2004	2,657,385.83	2,373,311	2,601,841	55,545	2.33	23,839
2005	1,150,682.48	1,009,033	1,106,194	44,488	2.60	17,111
2006	1,163,903.88	998,048	1,094,152	69,752	2.91	23,970
2007	1,417,138.09	1,183,169	1,297,098	120,040	3.26	36,822
2008	490,501.02	397,600	435,885	54,616	3.62	15,087
2009	57,248.17	44,825	49,141	8,107	4.02	2,017
2010	228,321.73	171,378	187,880	40,441	4.49	9,007
2011	246,330.80	175,831	192,762	53,569	5.01	10,692
2012	96,274.94	64,774	71,011	25,264	5.59	4,519
2013	68,490.16	43,005	47,146	21,344	6.22	3,432
2014	7,274.22	4,202	4,607	2,668	6.95	384
2016	42,352.64	19,787	21,692	20,660	8.55	2,416
2018	197,444.20	68,316	74,894	122,550	10.40	11,784

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2019	24,280.90	6,884	7,547	16,734	11.37	1,472
2020	67,776.24	14,965	16,406	51,370	12.35	4,160
2021	829,106.03	130,833	143,431	685,675	13.35	51,361
	12,116,489.46	9,812,696	10,719,808	1,396,681		219,937
CPG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2010	396,383.10	297,525	331,183	65,200	4.49	14,521
2020	5,164.22	1,140	1,269	3,895	12.35	315
	401,547.32	298,665	332,452	69,095		14,836
	23,249,326.88	18,464,024	19,970,658	3,278,668		511,217

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.4   2.20

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1908	37.37	37	37			
1909	2,303.21	2,303	2,303			
1910	502.84	503	503			
1911	1,108.68	1,109	1,109			
1912	733.81	734	734			
1913	1,010.21	1,010	1,010			
1914	888.96	889	889			
1915	1,230.55	1,231	1,231			
1916	1,614.02	1,614	1,614			
1917	2,112.50	2,112	2,113			
1918	1,440.03	1,440	1,440			
1919	6,961.10	6,961	6,961			
1920	9,666.56	9,667	9,667			
1921	8,239.67	8,240	8,240			
1922	9,147.68	9,148	9,148			
1923	10,623.11	10,623	10,623			
1924	13,285.66	13,286	13,286			
1925	14,170.57	14,171	14,171			
1926	9,628.96	9,629	9,629			
1927	11,343.02	11,343	11,343			
1928	10,149.03	10,149	10,149			
1929	10,739.67	10,740	10,740			
1930	6,603.53	6,604	6,604			
1931	5,093.99	5,094	5,094			
1932	3,622.99	3,609	3,623			
1933	1,970.27	1,953	1,970			
1934	2,435.58	2,401	2,436			
1935	3,209.37	3,144	3,209			
1936	3,321.00	3,234	3,321			
1937	5,752.70	5,569	5,753			
1938	4,693.40	4,516	4,693			
1939	5,700.84	5,452	5,701			
1940	7,876.57	7,486	7,877			
1941	9,527.56	8,997	9,528			
1942	7,579.36	7,111	7,579			
1943	5,545.21	5,169	5,545			
1944	7,329.18	6,786	7,329			
1945	7,667.66	7,053	7,668			
1946	12,182.01	11,128	12,113	69	3.98	17
1947	25,754.45	23,364	25,431	323	4.27	76
1948	24,185.06	21,788	23,716	469	4.56	103
1949	29,028.04	25,961	28,258	770	4.86	158

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

UGI-GAS
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1950	34,734.37	30,838	33,567	1,168	5.16	226
1951	40,413.70	35,617	38,768	1,645	5.46	301
1952	44,866.54	39,248	42,721	2,146	5.76	373
1953	38,855.17	33,728	36,712	2,143	6.07	353
1954	53,377.06	45,974	50,042	3,335	6.38	523
1955	66,124.51	56,508	61,508	4,617	6.69	690
1956	72,054.28	61,074	66,478	5,576	7.01	795
1957	74,776.80	62,878	68,441	6,335	7.32	865
1958	70,120.82	58,460	63,633	6,488	7.65	848
1959	76,359.99	63,130	68,716	7,644	7.97	959
1960	73,667.96	60,376	65,718	7,950	8.30	958
1961	63,785.56	51,819	56,404	7,382	8.63	855
1962	56,566.39	45,536	49,565	7,001	8.97	780
1963	65,502.88	52,246	56,869	8,634	9.31	927
1964	74,369.19	58,768	63,968	10,401	9.65	1,078
1965	91,518.30	71,623	77,960	13,558	10.00	1,356
1966	95,246.25	73,816	80,347	14,899	10.35	1,440
1967	104,969.71	80,530	87,655	17,314	10.71	1,617
1968	121,085.05	91,946	100,081	21,004	11.07	1,897
1969	124,298.21	93,385	101,648	22,650	11.44	1,980
1970	110,295.90	81,979	89,233	21,063	11.81	1,783
1971	97,150.19	71,405	77,723	19,427	12.19	1,594
1972	89,375.00	64,952	70,699	18,676	12.57	1,486
1973	121,761.44	87,456	95,194	26,567	12.96	2,050
1974	129,549.02	91,951	100,087	29,462	13.35	2,207
1975	89,255.01	62,576	68,113	21,142	13.75	1,538
1976	46,511.93	32,204	35,053	11,459	14.15	810
1977	80,449.89	54,986	59,851	20,599	14.56	1,415
1978	94,139.41	63,483	69,100	25,039	14.98	1,671
1979	295,931.40	196,859	214,277	81,654	15.40	5,302
1980	559,500.01	366,959	399,428	160,072	15.83	10,112
1981	632,227.67	408,609	444,763	187,465	16.27	11,522
1982	508,156.60	375,375	408,588	99,568	14.68	6,783
1983	528,251.25	385,095	419,168	109,083	15.06	7,243
1984	462,806.95	332,712	362,150	100,657	15.45	6,515
1985	650,298.77	460,672	501,432	148,866	15.85	9,392
1986	665,943.54	466,960	508,277	157,667	15.98	9,867
1987	746,041.88	514,620	560,154	185,888	16.41	11,328
1988	961,960.57	652,209	709,917	252,044	16.86	14,949
1989	1,045,281.19	695,948	757,526	287,756	17.32	16,614
1990	1,305,068.47	856,908	932,727	372,341	17.52	21,252
1991	1,300,058.50	836,588	910,609	389,449	18.01	21,624

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1992	1,219,900.55	772,441	840,787	379,114	18.25	20,773
1993	948,508.14	587,316	639,282	309,226	18.76	16,483
1994	1,346,970.37	818,554	890,980	455,991	19.04	23,949
1995	1,490,242.60	883,416	961,581	528,662	19.58	27,000
1996	1,388,119.57	805,387	876,648	511,472	19.90	25,702
1997	1,635,845.16	923,271	1,004,962	630,883	20.45	30,850
1998	1,809,642.52	996,751	1,084,944	724,699	20.80	34,841
1999	1,777,573.10	953,846	1,038,243	739,331	21.16	34,940
2000	1,812,165.70	945,407	1,029,057	783,109	21.55	36,339
2001	1,759,663.45	886,870	965,340	794,323	22.14	35,877
2002	1,018,187.03	496,875	540,839	477,348	22.56	21,159
2003	1,416,707.80	667,978	727,081	689,627	22.98	30,010
2004	1,113,175.48	505,827	550,583	562,593	23.42	24,022
2005	1,286,988.26	561,899	611,616	675,372	23.87	28,294
2006	1,351,439.73	565,172	615,179	736,261	24.34	30,249
2007	7,141,718.64	2,839,547	3,090,791	4,050,928	25.00	162,037
2008	3,006,177.69	1,136,936	1,237,532	1,768,645	25.48	69,413
2009	2,205,469.61	789,999	859,898	1,345,571	25.98	51,793
2010	1,431,393.42	483,095	525,839	905,554	26.50	34,172
2011	1,793,119.26	566,984	617,151	1,175,968	27.03	43,506
2012	2,213,259.25	651,584	709,236	1,504,023	27.56	54,573
2013	2,728,981.13	739,281	804,693	1,924,288	28.26	68,092
2014	2,026,062.85	502,464	546,922	1,479,141	28.81	51,341
2015	2,702,732.10	604,331	657,802	2,044,930	29.52	69,273
2016	2,885,706.55	575,698	626,636	2,259,071	30.09	75,077
2017	2,909,271.36	506,795	551,636	2,357,635	30.81	76,522
2018	3,944,065.06	585,694	637,516	3,306,549	31.54	104,837
2019	2,996,283.22	366,745	399,195	2,597,089	32.26	80,505
2020	3,215,045.49	308,323	335,603	2,879,442	33.00	87,256
2021	5,477,668.92	376,864	410,209	5,067,460	33.86	149,659
2022	4,788,689.73	198,252	215,793	4,572,896	34.73	131,670
2023	4,419,420.24	60,988	66,384	4,353,036	35.60	122,276
	89,528,917.29	31,285,954	34,039,212	55,489,705		2,038,722

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2022	273,611.74	11,328	55,832-	329,444	34.73	9,486
2023	346,579.33	4,783	23,574-	370,153	35.60	10,398
	620,191.07	16,111	79,406-	699,597		19,884
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1953	3,598.08	3,123	2,373	1,225	6.07	202
1954	4,598.13	3,960	3,009	1,589	6.38	249
1955	6,231.82	5,326	4,048	2,184	6.69	326
1956	4,305.71	3,650	2,774	1,532	7.01	219
1957	11,662.51	9,807	7,453	4,209	7.32	575
1958	12,720.76	10,605	8,059	4,661	7.65	609
1959	13,199.10	10,912	8,293	4,906	7.97	616
1960	5,317.94	4,358	3,312	2,006	8.30	242
1961	13,670.44	11,106	8,440	5,230	8.63	606
1962	11,279.86	9,080	6,901	4,379	8.97	488
1963	11,748.24	9,371	7,122	4,627	9.31	497
1964	14,664.74	11,588	8,807	5,858	9.65	607
1965	22,422.23	17,548	13,336	9,086	10.00	909
1966	16,631.96	12,890	9,796	6,836	10.35	660
1967	19,774.02	15,170	11,529	8,245	10.71	770
1968	25,903.13	19,670	14,949	10,955	11.07	990
1969	18,671.37	14,028	10,661	8,011	11.44	700
1970	35,677.02	26,517	20,152	15,525	11.81	1,315
1971	22,638.98	16,640	12,646	9,993	12.19	820
1972	19,573.79	14,225	10,811	8,763	12.57	697
1973	9,991.54	7,177	5,454	4,537	12.96	350
1974	76,738.25	54,467	41,393	35,345	13.35	2,648
1975	18,953.79	13,288	10,098	8,855	13.75	644
1976	4,204.92	2,911	2,212	1,993	14.15	141
1977	1,282.67	877	666	616	14.56	42
1978	106.67	72	55	52	14.98	3
1979	917.80	611	464	453	15.40	29
1980	13,158.94	8,631	6,559	6,600	15.83	417
1981	34,600.92	22,363	16,995	17,606	16.27	1,082
1982	31,907.75	23,570	17,913	13,995	14.68	953
1983	29,353.48	21,399	16,263	13,091	15.06	869
1984	30,241.06	21,740	16,522	13,719	15.45	888

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1985	52,076.41	36,891	28,036	24,040	15.85	1,517
1986	57,093.10	40,034	30,425	26,668	15.98	1,669
1987	72,476.71	49,994	37,994	34,483	16.41	2,101
1988	55,553.29	37,665	28,624	26,929	16.86	1,597
1989	77,468.27	51,578	39,198	38,271	17.32	2,210
1990	81,578.01	53,564	40,707	40,871	17.52	2,333
1991	84,146.69	54,148	41,151	42,996	18.01	2,387
1992	68,592.40	43,433	33,008	35,585	18.25	1,950
1993	74,940.75	46,403	35,265	39,676	18.76	2,115
1994	100,851.42	61,287	46,576	54,275	19.04	2,851
1995	109,229.70	64,751	49,209	60,021	19.58	3,065
1996	203,194.77	117,894	89,596	113,599	19.90	5,708
1997	299,906.31	169,267	128,638	171,268	20.45	8,375
1998	533,596.12	293,905	223,359	310,237	20.80	14,915
1999	406,049.14	217,886	165,587	240,462	21.16	11,364
2000	388,039.32	202,440	153,848	234,191	21.55	10,867
2001	340,512.31	171,618	130,425	210,088	22.14	9,489
2002	448,305.74	218,773	166,261	282,045	22.56	12,502
2003	347,483.17	163,838	124,512	222,971	22.98	9,703
2004	242,424.09	110,158	83,717	158,707	23.42	6,777
2005	425,524.91	185,784	141,190	284,335	23.87	11,912
2006	296,889.38	124,159	94,357	202,532	24.34	8,321
2007	643,068.61	255,684	194,312	448,756	25.00	17,950
2008	809,294.99	306,075	232,608	576,687	25.48	22,633
2009	471,580.35	168,920	128,374	343,206	25.98	13,210
2010	328,439.08	110,848	84,241	244,198	26.50	9,215
2011	616,565.55	194,958	148,162	468,403	27.03	17,329
2012	570,545.16	167,968	127,651	442,894	27.56	16,070
2013	630,471.33	170,795	129,799	500,672	28.26	17,717
2014	753,863.77	186,958	142,083	611,781	28.81	21,235
2015	1,061,735.75	237,404	180,420	881,316	29.52	29,855
2016	2,025,299.02	404,047	307,064	1,718,235	30.09	57,103
2017	650,071.09	113,242	86,061	564,011	30.81	18,306
2018	757,013.57	112,417	85,434	671,580	31.54	21,293
2019	1,537,572.70	188,199	143,026	1,394,547	32.26	43,228
2020	484,236.44	46,438	35,292	448,945	33.00	13,604

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2021	356,974.30	24,560	18,665	338,309	33.86	9,991
2022	708,926.56	29,350	22,305	686,621	34.73	19,770
2023	616,347.06	8,506	6,464	609,883	35.60	17,132
	18,333,684.96	5,648,519	4,292,708	14,040,977		519,532
	108,482,793.32	36,950,584	38,252,514	70,230,279		2,578,138

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.2 2.38

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

UGI-GAS
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1944	77.12	71	77			
1957	116.57	98	117			
1962	2,143.54	1,726	2,144			
1964	17,858.25	14,112	17,858			
1965	20,848.69	16,316	20,849			
1966	29,660.12	22,987	29,660			
1967	33,765.65	25,904	33,766			
1968	27,806.66	21,115	27,807			
1969	29,223.27	21,955	29,082	141	11.44	12
1970	46,311.14	34,421	45,595	716	11.81	61
1971	42,311.88	31,099	41,195	1,117	12.19	92
1972	30,514.27	22,176	29,375	1,139	12.57	91
1973	21,471.42	15,422	20,429	1,043	12.96	80
1974	24,232.03	17,199	22,782	1,450	13.35	109
1975	33,363.82	23,391	30,985	2,379	13.75	173
1976	7,070.79	4,896	6,485	585	14.15	41
1977	17,741.78	12,126	16,063	1,679	14.56	115
1978	23,200.86	15,645	20,724	2,477	14.98	165
1979	84,936.27	56,501	74,843	10,093	15.40	655
1980	174,756.46	114,618	151,827	22,929	15.83	1,448
1981	85,050.45	54,968	72,813	12,238	16.27	752
1982	129,178.96	95,424	126,402	2,777	14.68	189
1983	63,020.78	45,942	60,856	2,164	15.06	144
1984	58,770.61	42,250	55,966	2,805	15.45	182
1985	123,174.66	87,257	115,584	7,591	15.85	479
1986	140,144.62	98,269	130,171	9,974	15.98	624
1987	136,621.38	94,241	124,835	11,786	16.41	718
1988	175,226.18	118,803	157,371	17,856	16.86	1,059
1989	213,204.99	141,952	188,035	25,170	17.32	1,453
1990	213,839.80	140,407	185,988	27,852	17.52	1,590
1991	78,171.79	50,304	66,634	11,537	18.01	641
1992	96,572.79	61,150	81,001	15,571	18.25	853
1993	33,923.75	21,006	27,825	6,098	18.76	325
1994	111,621.17	67,832	89,853	21,769	19.04	1,143
1995	158,782.21	94,126	124,683	34,100	19.58	1,742
1996	44,689.40	25,929	34,346	10,343	19.90	520
1997	90,310.81	50,971	67,518	22,793	20.45	1,115
1998	55,859.17	30,767	40,755	15,104	20.80	726
1999	104,393.51	56,018	74,203	30,190	21.16	1,427
2000	92,808.40	48,418	64,136	28,672	21.55	1,330
2001	170,226.07	85,794	113,646	56,580	22.14	2,556
2002	54,780.31	26,733	35,411	19,369	22.56	859

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2003	133,116.54	62,764	83,139	49,977	22.98	2,175
2004	229,662.19	104,358	138,236	91,426	23.42	3,904
2005	221,217.95	96,584	127,939	93,279	23.87	3,908
2006	179,440.10	75,042	99,403	80,037	24.34	3,288
2008	542,709.86	205,253	271,885	270,824	25.48	10,629
2009	435,325.89	155,934	206,556	228,770	25.98	8,806
2010	540,006.27	182,252	241,417	298,589	26.50	11,268
2012	185,650.41	54,655	72,398	113,252	27.56	4,109
2013	64,881.01	17,576	23,282	41,599	28.26	1,472
2020	588,922.00	56,478	74,813	514,109	33.00	15,579
2021	64,271.78	4,422	5,858	58,414	33.86	1,725
2022	30,000.44	1,242	1,645	28,355	34.73	816
2023	30,000.98	414	548	29,453	35.60	827
	6,342,987.82	3,027,313	4,006,814	2,336,174		91,975
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1950	210.21	187	210			
1952	22,767.94	19,917	22,768			
1953	3,309.78	2,873	3,310			
1954	3,622.96	3,120	3,623			
1956	2,279.52	1,932	2,280			
1957	4,295.30	3,612	4,295			
1958	521.21	435	521			
1959	5,057.25	4,181	5,057			
1960	13,525.08	11,085	13,525			
1961	9,232.03	7,500	9,232			
1962	28,588.74	23,014	28,589			
1963	14,420.71	11,502	14,421			
1964	37,674.05	29,771	37,674			
1965	38,252.66	29,937	38,253			
1966	31,145.08	24,137	31,145			
1967	24,126.83	18,509	24,127			
1968	19,829.15	15,057	19,829			
1969	19,895.23	14,947	19,761	134	11.44	12
1970	22,697.47	16,870	22,303	394	11.81	33
1971	20,233.27	14,871	19,660	573	12.19	47
1972	17,248.52	12,535	16,572	677	12.57	54

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1973	11,462.25	8,233	10,884	578	12.96	45
1974	24,357.58	17,289	22,857	1,501	13.35	112
1975	16,278.93	11,413	15,089	1,190	13.75	87
1976	24,964.81	17,285	22,852	2,113	14.15	149
1977	43,019.88	29,403	38,872	4,147	14.56	285
1978	25,923.09	17,481	23,111	2,812	14.98	188
1979	50,209.00	33,400	44,157	6,052	15.40	393
1980	157,317.70	103,180	136,410	20,908	15.83	1,321
1981	85,092.09	54,995	72,707	12,386	16.27	761
1984	250.56	180	238	13	15.45	1
1985	76,822.00	54,421	71,948	4,874	15.85	308
1986	6,287.24	4,409	5,829	458	15.98	29
1987	4,510.87	3,112	4,114	397	16.41	24
1988	436.17	296	391	45	16.86	3
1989	61,329.96	40,833	53,984	7,346	17.32	424
1990	113,082.82	74,250	98,163	14,920	17.52	852
1991	3,006.21	1,934	2,557	449	18.01	25
1992	70,075.02	44,372	58,662	11,413	18.25	625
1993	67,033.51	41,507	54,875	12,159	18.76	648
1994	82,507.68	50,140	66,288	16,220	19.04	852
1995	26,754.06	15,860	20,968	5,786	19.58	296
1996	1,224.19	710	939	286	19.90	14
1997	216,506.32	122,196	161,550	54,956	20.45	2,687
1998	256,534.50	141,299	186,805	69,729	20.80	3,352
1999	8,423.67	4,520	5,976	2,448	21.16	116
2000	84,528.22	44,098	58,300	26,228	21.55	1,217
2001	118,285.79	59,616	78,816	39,470	22.14	1,783
2002	169,451.05	82,692	109,324	60,127	22.56	2,665
2003	148,208.91	69,881	92,387	55,822	22.98	2,429
2004	219,993.94	99,965	132,159	87,834	23.42	3,750
2007	122,097.83	48,546	64,181	57,917	25.00	2,317
2009	114,031.89	40,846	54,001	60,031	25.98	2,311
2010	62,504.19	21,095	27,889	34,615	26.50	1,306
2018	45.98	7	9	37	31.54	1
2021	6,060.85	417	551	5,510	33.86	163
2022	19,000.02	787	1,040	17,960	34.73	517
2023	18,999.99	262	346	18,654	35.60	524
	2,855,551.76	1,626,922	2,136,382	719,170		32,726

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1971	4,968.55	3,652	4,792	177	12.19	15
1972	11,988.91	8,713	11,432	557	12.57	44
1973	16,058.19	11,534	15,133	925	12.96	71
1974	23,468.94	16,658	21,856	1,613	13.35	121
1975	11,865.54	8,319	10,915	951	13.75	69
1976	6,583.75	4,559	5,982	602	14.15	43
1977	3,863.61	2,641	3,465	398	14.56	27
1978	5,202.81	3,509	4,604	599	14.98	40
1979	5,677.30	3,777	4,956	722	15.40	47
1980	25,101.07	16,463	21,600	3,501	15.83	221
1981	21,833.05	14,111	18,514	3,319	16.27	204
1982	13,732.01	10,144	13,309	423	14.68	29
1983	18,443.15	13,445	17,641	803	15.06	53
1984	28,887.11	20,767	27,247	1,640	15.45	106
1985	25,072.74	17,762	23,305	1,768	15.85	112
1986	26,946.24	18,895	24,791	2,155	15.98	135
1987	27,368.84	18,879	24,770	2,599	16.41	158
1988	27,093.60	18,369	24,101	2,993	16.86	178
1989	33,117.71	22,050	28,931	4,187	17.32	242
1990	49,114.89	32,249	42,312	6,803	17.52	388
1991	52,594.21	33,844	44,405	8,189	18.01	455
1992	51,075.96	32,341	42,433	8,643	18.25	474
1993	54,447.82	33,714	44,234	10,213	18.76	544
1994	58,261.39	35,405	46,453	11,808	19.04	620
1995	71,868.19	42,603	55,897	15,971	19.58	816
1996	66,416.54	38,535	50,560	15,857	19.90	797
1997	69,479.97	39,214	51,451	18,029	20.45	882
1998	43,006.89	23,688	31,080	11,927	20.80	573
1999	67,802.73	36,383	47,736	20,066	21.16	948
2000	15,166.98	7,913	10,382	4,785	21.55	222
2001	23,541.63	11,865	15,567	7,974	22.14	360
2002	27,333.17	13,339	17,501	9,832	22.56	436
2003	3,460.80	1,632	2,141	1,320	22.98	57
2004	30,471.60	13,846	18,167	12,305	23.42	525
2005	306.59	134	176	131	23.87	5
2006	27,829.29	11,638	15,270	12,560	24.34	516
2007	1,440.86	573	752	689	25.00	28
2008	23,288.84	8,808	11,557	11,732	25.48	460
2009	15,648.94	5,605	7,354	8,295	25.98	319
2010	25,692.68	8,671	11,377	14,316	26.50	540
2011	17,905.52	5,662	7,429	10,477	27.03	388
2012	25,067.10	7,380	9,683	15,384	27.56	558

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2013	43,102.38	11,676	15,320	27,783	28.26	983
2014	31,955.80	7,925	10,398	21,558	28.81	748
2015	28,077.76	6,278	8,237	19,841	29.52	672
2016	18,468.61	3,684	4,834	13,635	30.09	453
2017	39,898.29	6,950	9,119	30,780	30.81	999
2018	118,875.05	17,653	23,162	95,713	31.54	3,035
2019	2,661.57	326	428	2,234	32.26	69
2020	28,753.05	2,757	3,617	25,136	33.00	762
2021	22,635.34	1,557	2,043	20,592	33.86	608
2022	16,999.17	704	924	16,075	34.73	463
2023	16,998.99	235	308	16,691	35.60	469
	1,526,921.72	739,034	969,650	557,272		22,087
	10,725,461.30	5,393,269	7,112,846	3,612,616		146,788

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.6 1.37

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

UGI-GAS
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1906	692.34	692	692			
1907	1,520.99	1,521	1,521			
1908	705.13	705	705			
1909	1,020.38	1,020	1,020			
1910	420.02	420	420			
1911	910.18	910	910			
1912	1,178.42	1,178	1,178			
1913	1,031.57	1,032	1,032			
1914	1,043.99	1,044	1,044			
1915	662.27	662	662			
1916	1,267.86	1,268	1,268			
1917	1,429.46	1,429	1,429			
1918	847.77	848	848			
1919	1,246.93	1,247	1,247			
1920	1,202.69	1,203	1,203			
1921	1,771.84	1,772	1,772			
1922	2,993.44	2,993	2,993			
1923	4,268.03	4,268	4,268			
1924	4,363.19	4,363	4,363			
1925	4,562.40	4,562	4,562			
1926	4,125.81	4,126	4,126			
1927	4,046.47	4,046	4,046			
1928	3,218.29	3,218	3,218			
1929	3,659.70	3,660	3,660			
1930	2,560.18	2,560	2,560			
1931	2,056.53	2,057	2,057			
1932	1,036.92	1,033	1,037			
1933	897.90	890	898			
1934	1,062.87	1,048	1,063			
1935	1,131.34	1,108	1,131			
1936	1,458.11	1,420	1,458			
1937	1,915.95	1,855	1,916			
1938	1,511.93	1,455	1,512			
1939	1,485.10	1,420	1,485			
1940	1,675.31	1,592	1,675			
1941	2,056.13	1,942	2,056			
1942	1,792.77	1,682	1,793			
1943	1,176.54	1,097	1,177			
1944	2,288.41	2,119	2,288			
1945	2,543.53	2,339	2,544			
1946	3,909.96	3,572	3,910			
1947	8,406.58	7,626	8,407			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1948	8,092.82	7,291	8,073	20	4.56	4
1949	9,328.14	8,343	9,237	91	4.86	19
1950	9,753.17	8,659	9,587	166	5.16	32
1951	12,745.92	11,233	12,437	309	5.46	57
1952	13,269.42	11,608	12,852	417	5.76	72
1953	10,736.31	9,320	10,319	417	6.07	69
1954	9,055.01	7,799	8,635	420	6.38	66
1955	14,725.71	12,584	13,933	793	6.69	119
1956	18,894.00	16,015	17,732	1,162	7.01	166
1957	20,722.47	17,425	19,293	1,429	7.32	195
1958	19,731.26	16,450	18,213	1,518	7.65	198
1959	28,028.16	23,172	25,656	2,372	7.97	298
1960	21,073.44	17,271	19,122	1,951	8.30	235
1961	13,972.22	11,351	12,568	1,404	8.63	163
1962	14,410.25	11,600	12,844	1,567	8.97	175
1963	17,619.76	14,054	15,561	2,059	9.31	221
1964	20,002.34	15,806	17,500	2,502	9.65	259
1965	21,037.41	16,464	18,229	2,808	10.00	281
1966	22,406.65	17,365	19,227	3,180	10.35	307
1967	24,123.21	18,507	20,491	3,632	10.71	339
1968	28,774.01	21,850	24,192	4,582	11.07	414
1969	29,728.28	22,335	24,729	4,999	11.44	437
1970	24,363.35	18,108	20,049	4,314	11.81	365
1971	31,661.94	23,272	25,767	5,895	12.19	484
1972	37,632.54	27,349	30,281	7,352	12.57	585
1973	46,100.26	33,112	36,662	9,439	12.96	728
1974	40,774.13	28,941	32,044	8,731	13.35	654
1975	28,182.10	19,758	21,876	6,306	13.75	459
1976	20,468.59	14,172	15,691	4,777	14.15	338
1977	30,053.83	20,541	22,743	7,311	14.56	502
1978	40,324.48	27,193	30,108	10,216	14.98	682
1979	68,107.72	45,307	50,164	17,944	15.40	1,165
1980	130,072.87	85,311	94,457	35,616	15.83	2,250
1981	109,546.56	70,800	78,390	31,157	16.27	1,915
1982	188,537.85	139,273	154,203	34,334	14.68	2,339
1983	140,248.01	102,241	113,201	27,047	15.06	1,796
1984	95,746.08	68,832	76,211	19,535	15.45	1,264
1985	156,021.44	110,526	122,375	33,647	15.85	2,123
1986	141,803.14	99,432	110,091	31,712	15.98	1,984
1987	167,018.76	115,210	127,561	39,458	16.41	2,405
1988	175,553.88	119,026	131,786	43,768	16.86	2,596
1989	244,082.84	162,510	179,931	64,151	17.32	3,704

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1990	198,898.48	130,597	144,597	54,301	17.52	3,099
1991	127,099.09	81,788	90,556	36,543	18.01	2,029
1992	193,047.77	122,238	135,342	57,706	18.25	3,162
1993	109,740.00	67,951	75,236	34,504	18.76	1,839
1994	158,377.76	96,246	106,564	51,814	19.04	2,721
1995	224,399.16	133,024	147,284	77,115	19.58	3,938
1996	145,457.12	84,394	93,441	52,016	19.90	2,614
1997	182,836.11	103,193	114,256	68,581	20.45	3,354
1998	241,962.84	133,273	147,560	94,403	20.80	4,539
1999	162,361.07	87,123	96,463	65,898	21.16	3,114
2000	129,227.62	67,418	74,645	54,582	21.55	2,533
2001	174,752.35	88,075	97,517	77,236	22.14	3,489
2002	177,571.81	86,655	95,945	81,627	22.56	3,618
2003	462,297.93	217,973	241,340	220,958	22.98	9,615
2004	581,368.24	264,174	292,494	288,874	23.42	12,335
2005	460,489.29	201,050	222,603	237,886	23.87	9,966
2006	270,621.17	113,174	125,307	145,315	24.34	5,970
2008	799,950.34	302,541	334,974	464,976	25.48	18,249
2009	189,047.86	67,717	74,976	114,071	25.98	4,391
2010	213,406.96	72,025	79,746	133,661	26.50	5,044
2011	310,454.20	98,166	108,690	201,765	27.03	7,464
2012	513,719.92	151,239	167,452	346,268	27.56	12,564
2013	417,708.60	113,157	125,288	292,421	28.26	10,348
2014	466,595.78	115,716	128,121	338,475	28.81	11,749
2015	456,706.02	102,119	113,066	343,640	29.52	11,641
2016	686,073.08	136,872	151,545	534,528	30.09	17,764
2017	746,553.29	130,050	143,992	602,562	30.81	19,557
2018	883,442.23	131,191	145,255	738,187	31.54	23,405
2019	540,731.97	66,186	73,281	467,451	32.26	14,490
2020	217,181.25	20,828	23,061	194,120	33.00	5,882
2021	274,629.53	18,895	20,921	253,709	33.86	7,493
2022	249,998.30	10,350	11,460	238,539	34.73	6,868
2023	249,999.76	3,450	3,820	246,180	35.60	6,915
	13,608,392.46	5,351,266	5,917,975	7,690,417		294,223

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1959	245.76	203	246			
1960	2,151.30	1,763	2,151			
1961	75,690.37	61,490	75,690			
1962	16,927.20	13,626	16,927			
1963	22,943.49	18,300	22,943			
1964	28,400.21	22,442	28,400			
1965	29,395.47	23,005	29,395			
1966	36,408.56	28,217	36,408			
1967	32,174.73	24,683	31,848	326	10.71	30
1968	26,931.71	20,451	26,388	544	11.07	49
1969	37,722.84	28,341	36,568	1,155	11.44	101
1970	19,650.04	14,605	18,845	805	11.81	68
1971	9,667.21	7,105	9,168	500	12.19	41
1972	13,313.98	9,676	12,485	829	12.57	66
1973	38,836.17	27,894	35,991	2,845	12.96	220
1974	144,406.45	102,497	132,251	12,155	13.35	910
1975	99,258.76	69,589	89,790	9,469	13.75	689
1976	162,178.02	112,290	144,887	17,291	14.15	1,222
1977	227,638.93	155,587	200,753	26,886	14.56	1,847
1978	126,268.54	85,149	109,867	16,401	14.98	1,095
1979	78,656.93	52,324	67,513	11,144	15.40	724
1980	57,030.55	37,405	48,263	8,767	15.83	554
1981	109,907.92	71,033	91,653	18,255	16.27	1,122
1985	24,654.43	17,465	22,535	2,119	15.85	134
1986	27,447.15	19,246	24,833	2,614	15.98	164
1988	68,000.86	46,105	59,489	8,512	16.86	505
1989	58,448.77	38,915	50,212	8,237	17.32	476
1990	51,140.66	33,579	43,327	7,814	17.52	446
1991	39,011.61	25,104	32,392	6,620	18.01	368
1992	35,854.73	22,703	29,294	6,561	18.25	360
1993	51,676.44	31,998	41,287	10,390	18.76	554
1994	71,235.62	43,290	55,857	15,379	19.04	808
1995	49,500.84	29,344	37,862	11,638	19.58	594
1996	45,909.70	26,637	34,370	11,540	19.90	580
1997	34,534.58	19,491	25,149	9,385	20.45	459
1998	49,970.37	27,524	35,514	14,456	20.80	695
1999	46,832.83	25,130	32,425	14,408	21.16	681
2000	39,699.21	20,711	26,723	12,976	21.55	602
2001	45,124.99	22,743	29,345	15,780	22.14	713
2002	66,517.98	32,461	41,884	24,634	22.56	1,092
2003	78,667.19	37,092	47,860	30,808	22.98	1,341
2004	165,793.01	75,336	97,206	68,587	23.42	2,929

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2005	119,365.27	52,115	67,244	52,122	23.87	2,184
2006	70,424.87	29,452	38,002	32,423	24.34	1,332
2007	93,502.87	37,177	47,969	45,534	25.00	1,821
2008	109,845.80	41,544	53,604	56,242	25.48	2,207
2009	119,208.92	42,701	55,097	64,112	25.98	2,468
2010	90,572.74	30,568	39,442	51,131	26.50	1,929
2011	78,430.71	24,800	31,999	46,431	27.03	1,718
2012	113,394.32	33,383	43,074	70,320	27.56	2,552
2013	103,879.46	28,141	36,310	67,569	28.26	2,391
2014	114,396.21	28,370	36,606	77,791	28.81	2,700
2015	113,875.06	25,462	32,853	81,022	29.52	2,745
2016	95,701.05	19,092	24,634	71,067	30.09	2,362
2017	26,020.32	4,533	5,849	20,171	30.81	655
2018	56,220.18	8,349	10,773	45,448	31.54	1,441
2019	45,274.31	5,542	7,151	38,124	32.26	1,182
2020	1,226.17	118	152	1,074	33.00	33
2021	447.76	31	40	408	33.86	12
	3,797,612.13	1,993,927	2,566,794	1,230,818		51,971
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1965	1,895.12	1,483	1,707	188	10.00	19
1966	4,989.88	3,867	4,450	540	10.35	52
1967	7,905.20	6,065	6,980	925	10.71	86
1968	7,544.59	5,729	6,593	951	11.07	86
1969	7,037.34	5,287	6,085	953	11.44	83
1970	6,684.62	4,968	5,717	967	11.81	82
1971	4,822.66	3,545	4,080	743	12.19	61
1972	5,439.90	3,953	4,549	891	12.57	71
1973	14,933.80	10,726	12,344	2,590	12.96	200
1974	7,861.73	5,580	6,422	1,440	13.35	108
1975	9,613.04	6,740	7,757	1,856	13.75	135
1976	4,932.44	3,415	3,930	1,002	14.15	71
1977	4,347.30	2,971	3,419	928	14.56	64
1978	3,525.43	2,377	2,736	790	14.98	53
1979	2,829.16	1,882	2,166	663	15.40	43
1980	3,571.30	2,342	2,695	876	15.83	55
1981	10,155.76	6,564	7,554	2,602	16.27	160

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1982	8,768.97	6,478	7,455	1,314	14.68	90
1983	7,863.13	5,732	6,597	1,266	15.06	84
1984	27,433.37	19,722	22,697	4,736	15.45	307
1985	14,612.72	10,352	11,914	2,699	15.85	170
1986	17,814.51	12,492	14,376	3,438	15.98	215
1987	8,715.77	6,012	6,919	1,797	16.41	110
1988	6,897.76	4,677	5,382	1,515	16.86	90
1989	18,499.00	12,317	14,175	4,324	17.32	250
1990	17,820.76	11,701	13,466	4,355	17.52	249
1991	13,760.77	8,855	10,191	3,570	18.01	198
1992	16,073.60	10,178	11,713	4,360	18.25	239
1993	6,559.93	4,062	4,675	1,885	18.76	100
1994	29,217.11	17,755	20,433	8,784	19.04	461
1995	25,165.33	14,918	17,168	7,997	19.58	408
1996	58,774.81	34,101	39,245	19,530	19.90	981
1997	115,510.48	65,194	75,028	40,482	20.45	1,980
1998	69,851.40	38,474	44,278	25,574	20.80	1,230
1999	54,506.47	29,248	33,660	20,847	21.16	985
2000	47,330.67	24,692	28,417	18,914	21.55	878
2001	65,564.04	33,044	38,028	27,536	22.14	1,244
2002	94,751.21	46,239	53,214	41,537	22.56	1,841
2003	27,748.85	13,084	15,058	12,691	22.98	552
2004	181,730.07	82,578	95,034	86,696	23.42	3,702
2005	3,879.80	1,694	1,950	1,930	23.87	81
2006	111,923.85	46,807	53,868	58,056	24.34	2,385
2007	9,306.75	3,700	4,258	5,049	25.00	202
2008	78,534.49	29,702	34,182	44,352	25.48	1,741
2009	77,935.00	27,916	32,127	45,808	25.98	1,763
2010	77,881.91	26,285	30,250	47,632	26.50	1,797
2011	36,000.84	11,383	13,100	22,901	27.03	847
2012	9,612.23	2,830	3,257	6,355	27.56	231
2013	1,472.30	399	459	1,013	28.26	36
2014	2,742.40	680	783	1,960	28.81	68
2015	4,238.77	948	1,091	3,148	29.52	107
2016	13,257.55	2,645	3,044	10,214	30.09	339
2017	6,407.77	1,116	1,284	5,123	30.81	166
2018	19,731.53	2,930	3,372	16,360	31.54	519

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2019	1,948.17	238	274	1,674	32.26	52
2020	29,120.23	2,793	3,214	25,906	33.00	785
2021	20,518.00	1,412	1,625	18,893	33.86	558
	1,547,571.59	752,877	866,444	681,128		29,470
	18,953,576.18	8,098,070	9,351,213	9,602,363		375,664

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.6   1.98

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1953	691.53	637	692			
1956	2,239.85	2,019	2,240			
1957	4,785.87	4,284	4,786			
1960	16,750.58	14,666	16,751			
1961	12,800.59	11,122	12,801			
1962	22,033.72	18,998	21,897	137	6.20	22
1963	24,186.10	20,687	23,844	342	6.51	53
1964	21,937.83	18,613	21,453	485	6.82	71
1965	14,345.92	12,070	13,912	434	7.14	61
1966	22,819.15	19,031	21,935	884	7.47	118
1967	33,625.63	27,790	32,031	1,595	7.81	204
1968	78,227.64	64,060	73,835	4,392	8.15	539
1969	79,698.42	64,644	74,508	5,190	8.50	611
1970	56,628.40	45,466	52,404	4,224	8.87	476
1971	50,484.00	40,118	46,240	4,244	9.24	459
1972	74,487.40	58,547	67,481	7,006	9.63	728
1973	5,856.45	4,551	5,245	611	10.03	61
1974	2,435.60	1,871	2,157	279	10.44	27
1975	3,447.78	2,616	3,015	433	10.86	40
1976	1,925.80	1,442	1,662	264	11.30	23
1979	129,595.68	93,050	107,249	22,347	12.69	1,761
1980	273,942.52	193,707	223,266	50,677	13.18	3,845
1981	280,781.60	195,424	225,245	55,537	13.68	4,060
1982	232,089.47	177,224	204,268	27,822	12.85	2,165
1983	89,210.82	67,203	77,458	11,753	13.26	886
1984	47,248.78	35,087	40,441	6,808	13.69	497
1985	101,055.89	73,922	85,202	15,854	14.13	1,122
1986	78,585.49	56,582	65,216	13,369	14.58	917
1987	157,570.97	111,576	128,602	28,969	15.05	1,925
1988	283,620.35	197,343	227,457	56,164	15.52	3,619
1989	183,420.00	125,294	144,413	39,007	16.01	2,436
1990	203,975.86	136,664	157,518	46,457	16.50	2,816
1991	221,578.38	145,466	167,664	53,915	17.00	3,171
1992	121,714.83	78,214	90,149	31,566	17.52	1,802
1993	67,829.07	42,617	49,120	18,709	18.04	1,037
1994	215,739.93	132,378	152,578	63,162	18.58	3,399
1995	283,678.95	169,782	195,690	87,989	19.12	4,602
1996	638,322.65	372,142	428,929	209,393	19.67	10,645
1997	114,991.22	65,212	75,163	39,828	20.23	1,969
1998	89,135.98	49,096	56,588	32,548	20.80	1,565
1999	211,901.85	113,177	130,447	81,454	21.37	3,812
2000	61,111.51	31,595	36,416	24,695	21.95	1,125

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2001	5,688.76	2,842	3,276	2,413	22.55	107
2002	124,248.21	60,111	69,284	54,965	22.94	2,396
2005	16,976.59	7,286	8,398	8,579	24.60	349
2007	36,240.36	14,112	16,265	19,975	25.87	772
2008	123,273.33	45,660	52,628	70,646	26.34	2,682
2012	13,100.09	3,766	4,341	8,759	28.50	307
2014	217,660.91	52,935	61,013	156,648	29.56	5,299
2015	137,276.88	30,338	34,967	102,309	29.96	3,415
2016	122,361.10	24,130	27,812	94,549	30.52	3,098
2017	414,834.73	72,015	83,004	331,831	30.95	10,722
2018	224,701.21	33,615	38,745	185,957	31.26	5,949
2019	903,092.59	112,525	129,696	773,397	31.60	24,475
2020	3,023,610.46	299,337	345,015	2,678,596	31.84	84,127
2021	1,049,172.82	76,590	88,277	960,895	31.75	30,264
	11,028,748.10	3,931,249	4,530,688	6,498,060		236,631
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1954	860.15	787	860			
1956	7,054.30	6,360	7,054			
1957	11,192.51	10,019	11,193			
1958	5,050.93	4,489	5,051			
1959	689.61	608	690			
1960	32,725.24	28,653	32,725			
1961	10,605.59	9,215	10,606			
1962	22,867.17	19,717	22,867			
1963	60,787.04	51,993	60,787			
1964	79,108.77	67,119	79,109			
1965	131,939.84	111,005	131,940			
1966	124,040.09	103,449	123,686	354	7.47	47
1967	208,085.37	171,970	205,612	2,474	7.81	317
1968	233,579.88	191,276	228,694	4,886	8.15	600
1969	194,219.76	157,534	188,352	5,868	8.50	690
1970	271,294.84	217,820	260,431	10,864	8.87	1,225
1971	229,764.59	182,587	218,306	11,459	9.24	1,240
1972	257,964.38	202,760	242,425	15,539	9.63	1,614
1973	109,357.30	84,983	101,608	7,750	10.03	773
1974	90,753.81	69,699	83,334	7,420	10.44	711

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

PNG
SURVIVOR CURVE.. IOWA 45-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1975	52,979.89	40,194	48,057	4,923	10.86	453
1976	53,093.99	39,762	47,540	5,554	11.30	492
1977	29,803.40	22,021	26,329	3,475	11.75	296
1978	50,738.04	36,971	44,203	6,535	12.21	535
1979	92,133.69	66,152	79,093	13,041	12.69	1,028
1980	491,009.86	347,198	415,119	75,891	13.18	5,758
1981	230,826.16	160,655	192,083	38,743	13.68	2,832
1982	80,975.76	61,833	73,929	7,047	12.85	548
1983	42,059.45	31,683	37,881	4,178	13.26	315
1984	46,511.61	34,540	41,297	5,215	13.69	381
1985	72,222.02	52,830	63,165	9,057	14.13	641
1986	43,855.97	31,576	37,753	6,103	14.58	419
1987	107,897.65	76,402	91,348	16,550	15.05	1,100
1988	160,625.82	111,763	133,627	26,999	15.52	1,740
1989	30,425.01	20,783	24,849	5,576	16.01	348
1990	108,749.56	72,862	87,116	21,634	16.50	1,311
1991	127,229.75	83,526	99,866	27,364	17.00	1,610
1992	44,347.42	28,498	34,073	10,275	17.52	586
1993	29,918.28	18,798	22,475	7,443	18.04	413
1994	29,674.28	18,208	21,770	7,904	18.58	425
1995	34,913.41	20,896	24,984	9,930	19.12	519
1996	42,589.04	24,829	29,686	12,903	19.67	656
1997	147,679.42	83,749	100,132	47,547	20.23	2,350
1998	59,434.64	32,737	39,141	20,293	20.80	976
1999	107,844.18	57,600	68,868	38,976	21.37	1,824
2000	88,357.27	45,681	54,617	33,740	21.95	1,537
2001	82,991.73	41,454	49,563	33,428	22.55	1,482
2002	24,753.36	11,976	14,319	10,435	22.94	455
2003	6,572.47	3,059	3,657	2,915	23.55	124
2004	11,171.29	4,989	5,965	5,206	24.17	215
2005	8,155.02	3,500	4,185	3,970	24.60	161
2006	8,567.60	3,508	4,194	4,373	25.24	173
2007	26,075.02	10,154	12,140	13,935	25.87	539
2008	31,803.84	11,780	14,084	17,719	26.34	673
2009	68,220.04	23,836	28,499	39,721	27.00	1,471
2010	60,218.85	19,836	23,716	36,502	27.48	1,328
2011	489,447.99	151,142	180,709	308,739	27.98	11,034
2012	154,849.37	44,519	53,228	101,621	28.50	3,566
2013	5,908.18	1,569	1,876	4,032	29.03	139
2014	69,835.34	16,984	20,306	49,529	29.56	1,676

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2015	3,012,389.09	665,738	795,973	2,216,416	29.96	73,979
2016	2,481,717.48	489,395	585,133	1,896,585	30.52	62,142
2017	56,121.74	9,743	11,649	44,473	30.95	1,437
	11,086,635.15	4,826,972	5,763,527	5,323,108		196,904
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1940	90.00	90	90			
1942	90.00	89	90			
1943	132.66	130	133			
1944	519.95	508	520			
1945	66.33	64	66			
1946	197.92	191	198			
1947	210.99	202	211			
1948	189.93	181	190			
1949	87.26	83	87			
1950	87.44	82	87			
1951	87.28	82	87			
1953	1,265.02	1,165	1,265			
1955	1,296.62	1,177	1,289	8	4.14	2
1956	1,460.37	1,317	1,442	19	4.43	4
1957	7,995.25	7,157	7,835	160	4.72	34
1958	2,885.06	2,564	2,807	78	5.01	16
1959	2,623.82	2,315	2,534	89	5.30	17
1960	13,164.96	11,527	12,619	546	5.60	98
1961	21,807.35	18,948	20,743	1,064	5.90	180
1962	5,144.51	4,436	4,856	288	6.20	46
1963	11,141.18	9,529	10,432	709	6.51	109
1964	27,223.97	23,098	25,287	1,937	6.82	284
1965	25,450.83	21,413	23,442	2,009	7.14	281
1966	44,735.37	37,309	40,844	3,891	7.47	521
1967	40,165.22	33,194	36,339	3,826	7.81	490
1968	46,527.03	38,101	41,711	4,816	8.15	591
1969	40,719.90	33,028	36,157	4,562	8.50	537
1970	46,369.74	37,230	40,758	5,612	8.87	633
1971	37,753.88	30,002	32,845	4,909	9.24	531
1972	16,346.27	12,848	14,065	2,281	9.63	237
1973	17,281.90	13,430	14,703	2,579	10.03	257

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

CPG
SURVIVOR CURVE.. IOWA 45-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1974	15,500.00	11,904	13,032	2,468	10.44	236
1975	23,356.27	17,720	19,399	3,957	10.86	364
1976	7,679.24	5,751	6,296	1,383	11.30	122
1977	8,292.18	6,127	6,708	1,585	11.75	135
1978	4,682.18	3,412	3,735	947	12.21	78
1979	8,792.04	6,313	6,911	1,881	12.69	148
1980	17,159.04	12,133	13,283	3,876	13.18	294
1981	98,862.58	68,808	75,328	23,535	13.68	1,720
1982	107,317.69	81,948	89,713	17,605	12.85	1,370
1983	82,054.88	61,812	67,669	14,386	13.26	1,085
1984	56,055.83	41,627	45,571	10,485	13.69	766
1985	108,966.47	79,709	87,262	21,705	14.13	1,536
1986	78,897.92	56,807	62,190	16,708	14.58	1,146
1987	101,101.12	71,590	78,373	22,728	15.05	1,510
1988	89,032.58	61,949	67,819	21,214	15.52	1,367
1989	201,578.11	137,698	150,745	50,833	16.01	3,175
1990	181,749.75	121,772	133,310	48,439	16.50	2,936
1991	168,687.80	110,744	121,237	47,450	17.00	2,791
1992	259,022.46	166,448	182,219	76,803	17.52	4,384
1993	307,081.30	192,939	211,221	95,861	18.04	5,314
1994	257,960.73	158,285	173,283	84,678	18.58	4,557
1995	299,469.26	179,232	196,215	103,255	19.12	5,400
1996	383,632.67	223,658	244,850	138,782	19.67	7,056
1997	265,781.91	150,725	165,007	100,775	20.23	4,981
1998	699,360.80	385,208	421,708	277,653	20.80	13,349
1999	743,037.99	396,857	434,460	308,578	21.37	14,440
2000	582,884.63	301,351	329,905	252,980	21.95	11,525
2001	498,094.90	248,798	272,372	225,723	22.55	10,010
2002	223,078.26	107,925	118,151	104,927	22.94	4,574
2003	700,236.52	325,890	356,769	343,467	23.55	14,585
2004	1,411,277.60	630,277	689,998	721,280	24.17	29,842
2005	492,523.31	211,391	231,421	261,102	24.60	10,614
2006	776,322.51	317,904	348,026	428,296	25.24	16,969
2007	643,709.12	250,660	274,411	369,298	25.87	14,275
2008	820,138.66	303,779	332,563	487,576	26.34	18,511
2009	486,920.76	170,130	186,250	300,670	27.00	11,136
2010	543,937.56	179,173	196,150	347,787	27.48	12,656
2011	987,719.26	305,008	333,908	653,811	27.98	23,367
2012	353,222.86	101,552	111,174	242,049	28.50	8,493
2013	398,558.63	105,857	115,887	282,671	29.03	9,737
2014	361,466.55	87,909	96,239	265,228	29.56	8,973
2015	393,127.17	86,881	95,113	298,014	29.96	9,947

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2016	446,979.04	88,144	96,496	350,483	30.52	11,484
2017	844,671.07	146,635	160,529	684,142	30.95	22,105
2018	1,108,263.63	165,796	181,506	926,758	31.26	29,647
2019	573,973.60	71,517	78,293	495,680	31.60	15,686
2020	121,553.14	12,034	13,174	108,379	31.84	3,404
2021	35,273.65	2,575	2,819	32,455	31.75	1,022
	17,792,163.24	7,373,852	8,072,432	9,719,731		383,690
	39,907,546.49	16,132,073	18,366,647	21,540,899		817,225

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.4   2.05

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.0 OTHER PROPERTY ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1966	1,968.69	1,526	3,360-	5,328	10.35	515
1967	207.34	159	350-	557	10.71	52
1968	820.82	623	1,372-	2,192	11.07	198
1969	4,348.68	3,267	7,193-	11,542	11.44	1,009
1970	585.40	435	958-	1,543	11.81	131
1971	1,925.29	1,415	3,115-	5,041	12.19	414
1972	16,780.77	12,195	26,850-	43,630	12.57	3,471
2004	19,260.94	8,752	19,269-	38,530	23.42	1,645
2005	22,925.98	10,009	22,037-	44,963	23.87	1,884
	68,823.91	38,381	84,503-	153,327		9,319

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.5 13.54

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

UGI-GAS
SURVIVOR CURVE.. IOWA 45-R2
NET SALVAGE PERCENT.. 0

1929	141.00	141	141			
1955	2,275.45	2,066	2,275			
1956	989.22	892	989			
1957	545.83	489	546			
1958	236.59	210	237			
1959	739.15	652	739			
1960	6,231.82	5,456	6,232			
1961	5,465.73	4,749	5,429	37	5.90	6
1962	1,776.66	1,532	1,751	25	6.20	4
1963	1,519.13	1,299	1,485	34	6.51	5
1964	1,895.48	1,608	1,838	57	6.82	8
1965	611.14	514	588	24	7.14	3
1966	1,500.19	1,251	1,430	70	7.47	9
1967	7,810.50	6,455	7,379	432	7.81	55
1968	5,156.86	4,223	4,827	329	8.15	40
1969	2,743.23	2,225	2,543	200	8.50	24
1970	1,104.82	887	1,014	91	8.87	10
1971	31,924.90	25,370	29,001	2,923	9.24	316
1972	2,029.09	1,595	1,823	206	9.63	21
1973	5,741.28	4,462	5,101	641	10.03	64
1974	677.56	520	594	83	10.44	8
1975	501.75	381	436	66	10.86	6
1976	3,733.18	2,796	3,196	537	11.30	48
1977	1,421.54	1,050	1,200	221	11.75	19
1978	182.88	133	152	31	12.21	3
1979	5,235.99	3,759	4,297	939	12.69	74
1980	17,091.10	12,085	13,815	3,276	13.18	249
1981	121,509.06	84,570	96,675	24,834	13.68	1,815
1982	95,200.74	72,695	83,100	12,100	12.85	942
1983	6,768.10	5,098	5,828	940	13.26	71
1984	6,649.28	4,938	5,645	1,004	13.69	73
1985	25,257.56	18,476	21,121	4,137	14.13	293
1986	23,743.92	17,096	19,543	4,201	14.58	288
1987	25,830.88	18,291	20,909	4,922	15.05	327
1988	26,270.40	18,279	20,895	5,375	15.52	346
1989	52,802.47	36,069	41,232	11,571	16.01	723
1990	55,497.04	37,183	42,505	12,992	16.50	787
1991	30,826.21	20,237	23,134	7,693	17.00	453
1992	56,752.96	36,469	41,689	15,064	17.52	860
1993	45,455.69	28,560	32,648	12,808	18.04	710
1994	30,338.27	18,616	21,281	9,058	18.58	488
1995	22,678.63	13,573	15,516	7,163	19.12	375

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1996	22,335.06	13,021	14,885	7,450	19.67	379
1997	8,544.26	4,845	5,539	3,006	20.23	149
1998	8,784.27	4,838	5,531	3,254	20.80	156
1999	13,041.26	6,965	7,962	5,079	21.37	238
2000	2,551.99	1,319	1,508	1,044	21.95	48
2004	347.18	155	177	170	24.17	7
2005	3,317.00	1,424	1,628	1,689	24.60	69
2006	3,670.43	1,503	1,718	1,952	25.24	77
2010	54.74	18	21	34	27.48	1
2012	115,202.00	33,121	37,862	77,340	28.50	2,714
2013	22,348.33	5,936	6,786	15,563	29.03	536
2014	10,178.04	2,475	2,829	7,349	29.56	249
2015	499.19	110	126	373	29.96	12
2017	320.08	56	64	256	30.95	8
2018	5,899.53	883	1,009	4,890	31.26	156
2019	1,261.22	157	179	1,082	31.60	34
	953,217.86	593,776	678,603	274,615		14,356

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.1 1.51

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. 0						
1989	290.57	276	291			
1990	10,556.06	9,937	10,556			
1991	4,510.10	4,207	4,510			
1992	3,050.56	2,825	3,051			
1993	5,858.48	5,361	5,858			
1994	335.37	304	335			
1997	104.02	90	104			
	24,705.16	23,000	24,705			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1919	265.57	266	266			
1922	142.27	142	142			
1924	8,840.88	8,841	8,841			
1947	455.80	456	456			
1949	22,186.47	22,186	22,186			
1950	8,371.36	8,371	8,371			
1951	1,368.79	1,369	1,369			
1952	1,125.65	1,126	1,126			
1953	30,125.92	30,126	30,126			
1954	5,517.65	5,518	5,518			
1955	601.79	602	602			
1956	8,337.58	8,338	8,338			
1957	1,905.18	1,905	1,905			
1958	651.12	651	651			
1959	15,785.61	15,718	15,786			
1960	2,005.39	1,984	2,005			
1961	1,960.14	1,924	1,960			
1962	288.11	281	288			
1963	1,039.65	1,005	1,040			
1964	5,769.25	5,530	5,769			
1965	1,751.72	1,666	1,752			
1966	3,912.12	3,690	3,912			
1967	4,863.78	4,552	4,864			
1968	8,062.42	7,493	8,062			
1969	1,581.42	1,459	1,581			
1970	2,285.43	2,095	2,285			
1971	10,974.98	9,990	10,975			
1972	4,046.99	3,658	4,047			
1974	1,652.12	1,472	1,652			
1975	8,480.27	7,501	8,480			
1976	7,949.17	6,979	7,949			
1977	2,458.86	2,141	2,459			
1978	1,265.56	1,093	1,266			
1979	752.79	645	753			
1980	1,718.37	1,458	1,712	6	5.30	1
1981	10,162.67	8,542	10,031	132	5.58	24
1982	12,027.61	10,632	12,028			
1983	1,755.64	1,536	1,756			
1984	30,831.09	26,669	30,831			
1985	13,068.42	11,221	13,068			
1986	19,569.87	16,585	19,492	78	6.75	12
1987	23,586.65	19,801	23,272	315	6.98	45

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1988	13,276.05	10,982	12,907	369	7.42	50
1989	15,968.66	13,002	15,281	687	7.87	87
1990	33,323.13	26,678	31,355	1,968	8.34	236
1991	26,014.16	20,546	24,148	1,866	8.65	216
1992	15,045.39	11,659	13,703	1,343	9.15	147
1993	23,968.53	18,202	21,393	2,576	9.66	267
1994	51,100.60	37,988	44,647	6,453	10.18	634
1995	69,990.02	50,869	59,786	10,204	10.71	953
1996	45,414.72	32,344	38,014	7,401	11.11	666
1997	84,495.34	58,665	68,949	15,546	11.67	1,332
1998	75,399.07	50,955	59,887	15,512	12.23	1,268
1999	119,656.29	78,566	92,339	27,318	12.81	2,133
2000	199,968.82	127,340	149,663	50,306	13.40	3,754
2001	116,038.59	71,538	84,079	31,960	14.00	2,283
2002	42,457.03	25,287	29,720	12,737	14.60	872
2003	222,013.40	127,436	149,776	72,238	15.21	4,749
2004	109,705.10	60,535	71,147	38,558	15.84	2,434
2005	70,405.76	37,252	43,782	26,623	16.47	1,616
2006	85,043.37	43,015	50,556	34,488	17.10	2,017
2007	37,304.93	17,974	21,125	16,180	17.75	912
2008	97,908.80	44,764	52,611	45,298	18.40	2,462
2009	42,499.78	18,364	21,583	20,917	19.06	1,097
2011	14,980.73	5,711	6,712	8,269	20.29	408
2013	30,446.98	9,944	11,687	18,760	21.65	867
2018	12,429.20	2,256	2,651	9,778	24.80	394
2019	31,358.25	4,713	5,539	25,819	25.44	1,015
2020	191,812.76	22,826	26,827	164,985	25.91	6,368
	2,167,527.59	1,296,628	1,498,839	668,689		39,319
PNG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1962	460.81	449	461			
1976	21,500.00	18,877	21,500			
1984	1,544.96	1,336	1,545			
1987	5,496.89	4,615	5,497			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1988	2,425.60	2,006	2,426			
1997	821.60	570	755	67	11.67	6
2008	85,066.24	38,892	51,506	33,560	18.40	1,824
	117,316.10	66,745	83,689	33,627		1,830
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1915	0.25		0			
1920	46.40	46	46			
1921	65.00	65	65			
1925	288.57	289	289			
1927	8.25	8	8			
1928	265.80	266	266			
1929	32.00	32	32			
1930	401.84	402	402			
1931	576.33	576	576			
1932	862.24	862	862			
1933	179.53	180	180			
1936	339.96	340	340			
1937	180.10	180	180			
1938	702.11	702	702			
1939	70.20	70	70			
1940	114.20	114	114			
1942	93.19	93	93			
1947	107.86	108	108			
1948	228.20	228	228			
1951	115.54	116	116			
1952	399.62	400	400			
1954	526.32	526	526			
1955	866.71	867	867			
1956	3,485.13	3,485	3,485			
1957	166.98	167	167			
1958	807.41	807	807			
1959	3,980.48	3,963	3,980			
1960	3,557.12	3,518	3,557			
1961	940.90	924	941			
1962	2,160.12	2,105	2,160			
1963	2,440.64	2,359	2,441			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1964	1,463.53	1,403	1,464			
1965	852.14	810	852			
1966	4,391.44	4,142	4,391			
1967	7,725.03	7,231	7,725			
1968	9,375.01	8,713	9,375			
1969	1,802.13	1,663	1,802			
1970	4,312.49	3,953	4,312			
1971	727.19	662	727			
1972	12,970.95	11,726	12,971			
1973	4,161.73	3,736	4,162			
1974	5,521.13	4,920	5,480	41	3.81	11
1975	4,072.92	3,603	4,013	60	4.04	15
1976	1,691.94	1,486	1,655	37	4.27	9
1977	2,859.26	2,490	2,774	86	4.52	19
1978	9,079.27	7,842	8,735	344	4.77	72
1979	8,076.46	6,916	7,704	373	5.03	74
1980	16,025.59	13,599	15,148	878	5.30	166
1981	16,463.34	13,839	15,415	1,048	5.58	188
1982	18,913.59	16,720	18,624	289	5.45	53
1983	17,303.36	15,137	16,861	442	5.80	76
1984	24,489.09	21,183	23,596	893	6.16	145
1985	30,607.35	26,279	29,272	1,335	6.34	211
1986	47,810.95	40,520	45,135	2,676	6.75	396
1987	41,095.26	34,499	38,428	2,667	6.98	382
1988	31,108.85	25,733	28,664	2,445	7.42	330
1989	67,276.33	54,776	61,015	6,262	7.87	796
1990	73,855.80	59,129	65,864	7,992	8.34	958
1991	72,040.64	56,898	63,378	8,662	8.65	1,001
1992	46,648.02	36,148	40,265	6,383	9.15	698
1993	72,629.85	55,155	61,437	11,193	9.66	1,159
1994	50,628.58	37,637	41,924	8,705	10.18	855
1995	79,302.27	57,637	64,202	15,101	10.71	1,410
1996	207,257.72	147,609	164,421	42,837	11.11	3,856
1997	83,557.81	58,014	64,622	18,936	11.67	1,623
1998	20,844.66	14,087	15,691	5,153	12.23	421
1999	283,838.00	186,368	207,595	76,243	12.81	5,952
2000	62,321.83	39,687	44,207	18,115	13.40	1,352
2001	24,248.93	14,949	16,652	7,597	14.00	543
2007	20,518.49	9,886	11,012	9,507	17.75	536
2011	4,783.98	1,824	2,032	2,752	20.29	136
2014	897.06	268	299	599	22.25	27
2016	7,240.43	1,749	1,948	5,292	23.56	225

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
2017	323,394.81	68,527	76,332	247,063	24.17	10,222
2018	165,355.70	30,012	33,430	131,925	24.80	5,320
2019	186,196.01	27,985	31,172	155,024	25.44	6,094
2020	386,652.62	46,012	51,253	335,400	25.91	12,945
	2,586,398.54	1,306,960	1,452,045	1,134,354		58,276
	4,871,242.23	2,670,333	3,034,573	1,836,670		99,425

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.5 2.04

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387.1 OTHER EQUIPMENT - GRAPHIC DATA BASE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1980	53,900.00	53,900	53,900			
1981	184,018.30	184,018	184,018			
1982	328,563.00	328,563	328,563			
1983	92,573.18	92,573	92,573			
1984	103,914.03	103,914	103,914			
1985	109,975.52	109,976	109,976			
1986	113,888.51	113,889	113,889			
1987	112,021.79	112,022	112,022			
1988	167,324.21	167,324	167,324			
1989	77,363.35	77,363	77,363			
1990	11,534.69	11,535	11,535			
1991	1,588.30	1,588	1,588			
1992	3,540.35	3,540	3,540			
1993	514.88	515	515			
1995	4,074.64	4,075	4,075			
1998	10,727.14	10,727	10,727			
2001	13,978.74	12,581	12,806	1,173	2.50	469
2002	7,564.41	6,505	6,621	943	3.50	269
2003	93,599.07	76,751	78,123	15,476	4.50	3,439
	1,490,664.11	1,471,359	1,473,072	17,592		4,177

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.2 0.28

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

UGI-GAS - LANCASTER SERVICE BUILDING
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5
PROBABLE RETIREMENT YEAR.. 6-2026
NET SALVAGE PERCENT.. 0

1943	59.43	57	57	2	2.67	1
1944	149.04	143	144	5	2.67	2
1945	160.16	154	155	5	2.67	2
1949	355.93	341	344	12	2.68	4
1950	37,799.00	36,214	36,485	1,314	2.69	488
1951	12,293.22	11,773	11,861	432	2.69	161
1952	15,801.08	15,126	15,239	562	2.69	209
1953	17,382.45	16,633	16,757	625	2.69	232
1954	239,607.74	229,178	230,892	8,716	2.69	3,240
1955	932.69	892	899	34	2.69	13
1956	820.40	784	790	31	2.70	11
1957	3,223.63	3,078	3,101	123	2.70	46
1958	1,656.88	1,581	1,593	64	2.70	24
1959	2,242.75	2,139	2,155	88	2.70	33
1960	4,893.36	4,665	4,700	193	2.70	71
1961	15,449.19	14,720	14,830	619	2.70	229
1962	11,135.11	10,602	10,681	454	2.71	168
1963	7,834.78	7,455	7,511	324	2.71	120
1964	10,008.31	9,517	9,588	420	2.71	155
1965	5,180.81	4,923	4,960	221	2.71	82
1966	315.95	300	302	14	2.71	5
1967	440.99	418	421	20	2.71	7
1968	1,622.38	1,538	1,550	73	2.71	27
1969	6,835.36	6,476	6,524	311	2.71	115
1970	2,728.90	2,583	2,602	127	2.71	47
1971	1,339.89	1,267	1,276	63	2.72	23
1972	543.86	514	518	26	2.72	10
1973	2,934.98	2,770	2,791	144	2.72	53
1978	1,596.88	1,499	1,510	87	2.72	32
1980	5,857.50	5,486	5,527	330	2.72	121
1983	14,559.47	13,622	13,724	836	2.79	300
1985	12,065.43	11,288	11,372	693	2.65	262
1988	50,749.12	47,202	47,555	3,194	2.67	1,196
1989	8,120.75	7,536	7,592	528	2.68	197
1990	119,302.94	110,307	111,132	8,171	2.73	2,993
1992	46,382.43	42,663	42,982	3,400	2.75	1,236
1994	1,677,780.70	1,534,330	1,545,803	131,978	2.76	47,818
1995	21,591.68	19,692	19,839	1,752	2.75	637
1996	2,203.41	2,006	2,021	182	2.71	67
1998	25,219.24	22,765	22,935	2,284	2.75	831
2000	8,158.17	7,305	7,360	799	2.75	291

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. 0						
2001	23,624.17	21,049	21,206	2,418	2.75	879
2002	46,085.21	40,924	41,230	4,855	2.71	1,792
2003	134,242.68	118,335	119,220	15,023	2.76	5,443
2004	71,754.76	62,965	63,436	8,319	2.72	3,058
2005	59,030.79	51,439	51,824	7,207	2.73	2,640
2012	73,434.54	59,284	59,727	13,707	2.75	4,984
2014	122,043.63	94,730	95,438	26,605	2.74	9,710
2015	9,281.96	7,022	7,075	2,207	2.74	805
2016	79,714.90	58,415	58,852	20,863	2.73	7,642
2018	20,438.20	13,647	13,749	6,689	2.74	2,441
2020	28,733.14	16,131	16,252	12,482	2.73	4,572
2022	1,964,913.18	696,365	701,572	1,263,341	2.73	462,762
2023	601,957.90	93,484	94,183	507,775	2.72	186,682
	5,632,591.05	3,545,332	3,571,842	2,060,749		754,969
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2030						
NET SALVAGE PERCENT.. 0						
1951	800.31	723	728	72	6.37	11
1953	24,478.83	22,063	22,228	2,251	6.39	352
1954	20,116.86	18,110	18,245	1,871	6.40	292
1955	789,782.35	710,172	715,482	74,300	6.41	11,591
1956	1,030.99	926	933	98	6.42	15
1957	10,092.77	9,053	9,121	972	6.43	151
1958	2,445.55	2,191	2,207	238	6.44	37
1959	5,548.15	4,963	5,000	548	6.45	85
1960	4,877.78	4,357	4,390	488	6.46	76
1961	531,931.76	474,467	478,015	53,917	6.47	8,333
1962	334.45	298	300	34	6.47	5
1963	274.27	244	246	28	6.48	4
1966	3,812.57	3,374	3,399	413	6.50	64
1967	2,757.53	2,436	2,454	303	6.51	47
1969	856.72	754	760	97	6.53	15
1970	8,586.49	7,543	7,599	987	6.53	151
1971	17,031.63	14,930	15,042	1,990	6.54	304
1972	3,352.40	2,932	2,954	398	6.55	61
1973	2,831.49	2,471	2,489	342	6.55	52

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2030						
NET SALVAGE PERCENT.. 0						
1974	1,200,663.16	1,045,465	1,053,283	147,381	6.56	22,467
1975	22,526.91	19,571	19,717	2,810	6.56	428
1976	53,019.42	45,943	46,287	6,733	6.57	1,025
1977	34,894.73	30,163	30,389	4,506	6.57	686
1978	15,946.86	13,746	13,849	2,098	6.58	319
1979	147,852.13	127,100	128,050	19,802	6.58	3,009
1980	464,672.60	398,234	401,212	63,461	6.59	9,630
1981	56,919.44	48,635	48,999	7,921	6.59	1,202
1982	38,274.54	33,039	33,286	4,988	6.58	758
1983	2,890.82	2,482	2,501	390	6.67	58
1984	89,028.04	76,315	76,886	12,142	6.58	1,845
1985	57,289.37	48,965	49,331	7,958	6.55	1,215
1986	139,000.77	118,317	119,202	19,799	6.56	3,018
1987	3,305.19	2,799	2,820	485	6.60	73
1988	2,076.87	1,755	1,768	309	6.52	47
1989	965,568.04	809,532	815,585	149,983	6.65	22,554
1990	706,485.26	589,350	593,757	112,728	6.66	16,926
1991	56,952.53	47,385	47,739	9,213	6.56	1,404
1992	350,298.47	289,101	291,263	59,036	6.67	8,851
1993	36,768.43	30,165	30,391	6,378	6.68	955
1994	354,770.73	289,919	292,087	62,684	6.60	9,498
1995	57,663.12	46,834	47,184	10,479	6.59	1,590
1996	43,084.49	34,717	34,977	8,108	6.63	1,223
1997	18,060.88	14,454	14,562	3,499	6.61	529
1998	265,441.28	210,495	212,069	53,372	6.66	8,014
1999	63,044.02	49,578	49,949	13,095	6.65	1,969
2000	1,485,042.98	1,158,631	1,167,295	317,748	6.62	47,998
2001	470,007.52	362,752	365,465	104,543	6.65	15,721
2002	172,725.93	131,824	132,810	39,916	6.67	5,984
2003	216,118.71	163,040	164,259	51,860	6.67	7,775
2004	251,735.93	187,518	188,920	62,816	6.68	9,404
2005	753,627.45	554,896	559,045	194,582	6.63	29,349
2006	210,683.51	152,640	153,781	56,902	6.65	8,557
2007	817,480.24	582,700	587,057	230,423	6.65	34,650
2008	545,092.38	381,020	383,869	161,223	6.67	24,171
2009	131,681.97	90,307	90,982	40,700	6.64	6,130
2010	91,797.98	61,468	61,928	29,870	6.66	4,485
2011	74,744.13	48,771	49,136	25,608	6.66	3,845
2012	248,364.26	157,364	158,541	89,824	6.65	13,507
2013	35,837.92	21,940	22,104	13,734	6.65	2,065
2014	442,334.38	260,093	262,038	180,297	6.66	27,072

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

UGI-GAS - READING SERVICE BUILDING
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5
PROBABLE RETIREMENT YEAR.. 6-2030
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2015	381,309.24	213,914	215,514	165,796	6.65	24,932
2016	805,897.67	426,723	429,914	375,984	6.66	56,454
2017	192,306.04	94,999	95,709	96,597	6.66	14,504
2018	1,022,829.81	462,933	466,395	556,435	6.65	83,674
2019	2,654,481.36	1,071,349	1,079,360	1,575,121	6.65	236,860
2020	67,173.39	23,182	23,355	43,818	6.64	6,599
2021	362,357.10	99,213	99,955	262,402	6.63	39,578
2022	656,695.14	121,554	122,463	534,232	6.60	80,944
2023	532,069.56	37,883	38,166	493,903	6.52	75,752
	19,299,835.60	12,572,780	12,666,794	6,633,042		1,000,949

UGI-GAS - BETHLEHEM SERVICE BUILDING
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5
PROBABLE RETIREMENT YEAR.. 3-2050
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1965	453,217.33	307,458	309,757	143,460	22.12	6,486
1966	67,530.18	45,541	45,882	21,649	22.24	973
1967	9,289.08	6,227	6,274	3,016	22.35	135
1968	6,116.52	4,074	4,104	2,012	22.47	90
1969	12,678.67	8,394	8,457	4,222	22.57	187
1970	9,017.44	5,930	5,974	3,043	22.68	134
1971	5,197.77	3,396	3,421	1,776	22.78	78
1975	343.98	218	220	124	23.17	5
1976	2,969.56	1,871	1,885	1,085	23.26	47
1977	2,287.29	1,429	1,440	848	23.35	36
1981	757.98	457	460	298	23.68	13
1982	5,397.42	3,472	3,498	1,899	23.02	82
1984	23,183.72	14,652	14,762	8,422	23.00	366
1987	77,174.31	47,045	47,397	29,778	23.38	1,274
1989	23,989.19	14,317	14,424	9,565	23.31	410
1990	136,615.53	80,084	80,683	55,933	23.65	2,365
1991	1,719.87	995	1,002	717	23.68	30
1992	55,042.35	31,385	31,620	23,423	23.75	986
1994	10,008.36	5,551	5,593	4,416	23.69	186
1996	302,475.74	162,187	163,400	139,076	23.78	5,848
1997	200,645.79	105,821	106,612	94,034	23.75	3,959
1998	97,620.04	50,284	50,660	46,960	24.00	1,957
1999	75,017.36	37,861	38,144	36,873	24.04	1,534

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2050						
NET SALVAGE PERCENT.. 0						
2000	1,426.84	707	712	715	23.90	30
2001	96,880.76	46,871	47,221	49,659	24.01	2,068
2002	60,938.96	28,824	29,040	31,899	23.95	1,332
2003	65,996.03	30,305	30,532	35,464	24.14	1,469
2004	89,542.55	39,990	40,289	49,254	24.17	2,038
2005	177,934.58	77,366	77,945	99,990	24.05	4,158
2006	24,852.97	10,438	10,516	14,337	24.17	593
2007	25,774.02	10,462	10,540	15,234	24.15	631
2008	2,078.83	812	818	1,261	24.18	52
2009	1,633.83	614	619	1,015	24.11	42
2010	11,415.88	4,085	4,116	7,300	24.23	301
2011	101,582.18	34,660	34,919	66,663	24.13	2,763
2012	73,361.95	23,623	23,800	49,562	24.21	2,047
2013	45,778.31	13,889	13,993	31,785	24.10	1,319
2014	309,875.93	87,447	88,101	221,775	24.17	9,176
2015	319,877.30	83,488	84,112	235,765	24.07	9,795
2016	634,420.11	150,865	151,993	482,427	24.04	20,068
2017	525,575.26	112,053	112,891	412,684	23.99	17,202
2018	1,482,857.14	277,294	279,367	1,203,490	23.91	50,334
2019	1,379,576.30	219,077	220,715	1,158,861	23.83	48,630
2020	220,249.06	28,368	28,580	191,669	23.67	8,098
2021	305,047.23	29,437	29,657	275,390	23.41	11,764
2022	52,874.62	3,247	3,271	49,603	22.95	2,161
2023	13,968,553.06	314,292	316,642	13,651,911	21.72	628,541
	21,556,399.18	2,566,863	2,586,057	18,970,342		851,793
UGI-GAS - LEBANON SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2027						
NET SALVAGE PERCENT.. 0						
1992	1,964,102.72	1,757,086	1,770,224	193,878	3.71	52,258
1993	15,189.26	13,528	13,629	1,560	3.75	416
1994	10,032.68	8,909	8,976	1,057	3.72	284
2000	1,875.94	1,618	1,630	246	3.75	66

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LEBANON SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2027						
NET SALVAGE PERCENT.. 0						
2001	34,130.92	29,257	29,476	4,655	3.75	1,241
2022	7,522.95	2,164	2,180	5,343	3.71	1,440
2023	50,199.22	5,994	6,039	44,160	3.69	11,967
	2,083,053.69	1,818,556	1,832,154	250,900		67,672
UGI-GAS - STONE RIDGE SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2059						
NET SALVAGE PERCENT.. 0						
2009	4,739,134.55	1,511,784	1,523,089	3,216,046	30.95	103,911
2011	172,554.12	49,609	49,980	122,574	30.98	3,957
2020	35,115.39	3,663	3,690	31,425	30.06	1,045
2021	38,492.01	2,995	3,017	35,475	29.65	1,196
2022	20,137.39	995	1,002	19,135	28.89	662
2023	601,539.22	10,948	11,030	590,509	26.97	21,895
	5,606,972.68	1,579,994	1,591,809	4,015,164		132,666
UGI-GAS - GAS TRAINING CENTER						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2071						
NET SALVAGE PERCENT.. 0						
2021	27,836,758.65	1,795,471	1,808,897	26,027,861	36.26	717,812
2022	900,000.00	36,900	37,176	862,824	35.13	24,561
2023	2,646,645.00	40,229	40,530	2,606,115	32.29	80,710
	31,383,403.65	1,872,600	1,886,603	29,496,801		823,083
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1871	2,385.33	2,385	2,385			
1905	642.75	643	643			
1910	67.06	67	67			
1911	241.41	241	241			
1915	150.63	151	151			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES SURVIVOR CURVE.. IOWA 40-R2 NET SALVAGE PERCENT.. 0						
1922	250.95	251	251			
1923	297.04	297	297			
1924	61.13	61	61			
1928	44,791.52	44,792	44,792			
1929	1,227.11	1,227	1,227			
1931	6,591.16	6,591	6,591			
1932	589.45	589	589			
1933	40.24	40	40			
1934	309.40	309	309			
1935	4,124.32	4,124	4,124			
1937	242.44	242	242			
1938	143.77	144	144			
1940	95.93	96	96			
1943	273.84	274	274			
1947	6,946.66	6,947	6,947			
1948	401.47	401	401			
1949	1,806.43	1,806	1,806			
1950	2,196.55	2,185	2,197			
1951	233.36	231	233			
1953	2,899.07	2,828	2,853	46	0.98	46
1955	1,973.05	1,899	1,916	57	1.51	38
1957	1,355.54	1,285	1,297	59	2.07	29
1958	5,763.15	5,425	5,474	290	2.35	123
1959	1,512.13	1,413	1,426	86	2.63	33
1960	3,574.90	3,314	3,344	231	2.92	79
1961	649.28	597	602	47	3.21	15
1962	9,412.34	8,589	8,666	746	3.50	213
1963	12,936.88	11,711	11,816	1,121	3.79	296
1964	3,052.55	2,741	2,766	287	4.08	70
1966	2,516.15	2,222	2,242	274	4.67	59
1967	1,274.89	1,117	1,127	148	4.96	30
1968	419.83	365	368	52	5.26	10
1970	80.61	69	70	11	5.87	2
1971	1,544.75	1,306	1,318	227	6.19	37
1972	1,090.13	913	921	169	6.51	26
1975	164.27	133	134	30	7.54	4
1976	3,452.10	2,770	2,795	657	7.90	83
1977	7,165.00	5,682	5,733	1,432	8.28	173
1978	6,220.72	4,872	4,916	1,305	8.67	151
1979	3,107.33	2,403	2,425	683	9.07	75
1980	5,058.60	3,858	3,893	1,166	9.49	123
1983	369.74	298	301	69	9.75	7

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1986	5,526.05	4,269	4,307	1,219	11.04	110
1988	338.67	254	256	82	11.90	7
1989	11,535.55	8,476	8,552	2,984	12.45	240
1991	3,137.18	2,223	2,243	894	13.37	67
1994	17,386.12	11,541	11,644	5,742	14.94	384
1995	5,075.97	3,298	3,328	1,748	15.36	114
1997	38,896.24	24,015	24,230	14,666	16.42	893
1998	20,290.00	12,211	12,320	7,970	16.87	472
1999	9,250.00	5,394	5,442	3,808	17.52	217
2000	4,627.46	2,621	2,644	1,983	17.99	110
2001	14,287.96	7,813	7,883	6,405	18.65	343
2002	39,331.76	20,803	20,989	18,342	19.15	958
2003	18,220.00	9,299	9,382	8,838	19.66	450
2005	53,233.48	25,116	25,341	27,892	20.71	1,347
2007	2,169.82	931	939	1,230	21.96	56
2011	148,951.37	50,822	51,277	97,674	24.13	4,048
2012	1,935.54	614	620	1,316	24.73	53
2013	5,265.73	1,548	1,562	3,704	25.21	147
2014	34,471.72	9,300	9,383	25,088	25.71	976
2015	20,002.66	4,897	4,941	15,062	26.22	574
2016	52,555.80	11,510	11,613	40,943	26.75	1,531
2017	7,563.46	1,460	1,473	6,090	27.17	224
2018	262,071.27	43,530	43,920	218,151	27.61	7,901
2019	145,916.08	20,224	20,405	125,511	27.97	4,487
2020	106,559.48	11,785	11,891	94,669	28.15	3,363
2021	33,284.92	2,703	2,727	30,558	28.27	1,081
	1,211,587.25	436,561	439,825	771,762		31,875
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1960	100,067.62	71,358	76,294	23,773	20.10	1,183
1961	86,146.04	61,132	65,361	20,785	20.21	1,028
1962	139,981.34	98,841	105,678	34,303	20.32	1,688
1963	9,404.23	6,607	7,064	2,340	20.42	115
1964	3,660.00	2,558	2,735	925	20.53	45
1965	475.28	330	353	122	20.63	6
1966	295.13	204	218	77	20.73	4

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1967	853.95	587	628	226	20.82	11
1968	3,544.15	2,423	2,591	954	20.92	46
1969	656.51	446	477	180	21.01	9
1970	2,308.59	1,559	1,667	642	21.10	30
1971	74,315.06	49,897	53,349	20,966	21.18	990
1972	5,243.38	3,497	3,739	1,504	21.27	71
1973	5,824.04	3,860	4,127	1,697	21.35	79
1974	1,070.45	705	754	317	21.43	15
1975	19,982.00	13,060	13,963	6,019	21.51	280
1976	97,770.89	63,452	67,841	29,930	21.58	1,387
1977	260,875.91	168,015	179,637	81,238	21.66	3,751
1978	14,771.52	9,441	10,094	4,677	21.73	215
1979	31,127.48	19,736	21,101	10,026	21.80	460
1980	49,955.56	31,419	33,592	16,363	21.86	749
1981	48,677.50	30,351	32,451	16,227	21.93	740
1982	16,005.63	10,561	11,292	4,714	21.40	220
1983	15,829.25	10,321	11,035	4,794	21.61	222
1984	47,340.07	30,667	32,788	14,552	21.48	677
1985	68,374.47	43,698	46,721	21,654	21.74	996
1986	219,189.40	138,922	148,532	70,657	21.67	3,261
1987	95,221.16	59,780	63,915	31,306	21.64	1,447
1988	78,530.36	48,783	52,158	26,373	21.65	1,218
1989	133,148.76	81,767	87,423	45,726	21.68	2,109
1990	1,467.04	890	952	515	21.75	24
1991	12,693.53	7,591	8,116	4,577	21.85	209
1992	107,764.72	63,473	67,864	39,901	21.98	1,815
1993	237,846.63	138,569	148,154	89,692	21.85	4,105
1994	9,185.18	5,257	5,621	3,565	22.05	162
1995	132,495.37	74,767	79,939	52,556	22.01	2,388
1996	77,268.81	42,923	45,892	31,377	22.00	1,426
1997	4,604,109.67	2,513,383	2,687,246	1,916,864	22.04	86,972
1998	279,386.10	149,611	159,960	119,426	22.12	5,399
1999	84,505.25	44,306	47,371	37,134	22.23	1,670
2000	89,361.09	45,985	49,166	40,195	22.16	1,814
2001	722,355.35	364,067	389,251	333,104	22.14	15,045
2002	42,093.72	20,727	22,161	19,933	22.17	899
2003	180,049.74	86,370	92,345	87,705	22.24	3,944
2004	145,578.20	67,839	72,532	73,046	22.34	3,270
2005	166,367.90	75,398	80,614	85,754	22.32	3,842
2006	139,476.18	61,258	65,496	73,981	22.34	3,312
2007	873,823.56	370,501	396,130	477,693	22.41	21,316

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
2008	79,004.84	32,329	34,565	44,439	22.38	1,986
2009	53,933.31	21,196	22,662	31,271	22.40	1,396
2010	195,541.46	73,641	78,735	116,806	22.34	5,229
2011	313,875.66	112,619	120,409	193,466	22.34	8,660
2012	49,250.77	16,706	17,862	31,389	22.40	1,401
2013	122,264.10	39,027	41,727	80,537	22.39	3,597
2014	163,436.77	48,753	52,125	111,311	22.35	4,980
2015	94,594.58	26,127	27,934	66,660	22.27	2,993
2016	606,727.01	152,895	163,471	443,256	22.26	19,913
2017	58,017.51	13,124	14,032	43,986	22.24	1,978
2018	71,547.06	14,209	15,192	56,355	22.20	2,539
2019	6,718.32	1,137	1,216	5,503	22.10	249
2020	45,537.61	6,266	6,699	38,838	21.94	1,770
2021	220,832.84	22,790	24,366	196,466	21.71	9,050
2022	258,647.19	16,967	18,141	240,506	21.38	11,249
2023	266,057.20	6,385	6,827	259,231	20.29	12,776
	12,142,460.00	5,801,063	6,202,351	5,940,109		270,430
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
1960	27,374.98	27,375	27,375			
1961	2,250.14	2,250	2,250			
1962	11,395.40	11,395	11,395			
1964	212.41	212	212			
1965	479.69	480	480			
1972	4,846.95	4,847	4,847			
1973	59,338.04	59,338	59,338			
1976	674.99	675	675			
1977	9,114.69	9,115	9,115			
1978	24,124.85	24,125	24,125			
1979	540.75	541	541			
1980	8,726.53	8,727	8,727			
1981	52,430.77	52,431	52,431			
1982	22,292.87	22,293	22,293			
1984	11,417.15	11,417	11,417			
1986	31,130.64	31,131	31,131			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
1987	11,362.33	11,362	11,362			
1988	15,773.37	15,773	15,773			
1989	8,654.63	8,655	8,655			
1990	94,337.02	94,337	94,337			
1992	6,049.58	6,050	6,050			
1993	1,598.34	1,598	1,598			
1994	38,859.45	38,859	38,859			
1995	4,586.75	4,587	4,587			
1996	1,532.27	1,532	1,532			
1997	1,129.92	1,130	1,130			
1998	3,483.10	3,483	3,483			
2001	6,551.41	6,551	6,551			
2002	8,685.69	8,686	8,686			
2003	26,975.97	26,976	26,976			
2004	262,708.52	262,709	262,709			
2005	28,203.02	28,203	28,203			
2008	29,302.79	29,303	29,303			
2010	189,349.18	189,349	189,349			
2011	217,404.63	217,405	217,405			
2014	19,697.18	19,697	19,697			
2016	36,430.01	36,430	36,430			
2017	42,967.09	42,967	42,967			
2018	58,528.05	58,528	58,528			
2019	838,990.00	838,990	838,990			
	2,219,511.15	2,219,512	2,219,511			
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2001	6,479.79	3,003	3,316	3,163	26.04	121
2002	3,717,459.49	1,678,433	1,853,623	1,863,836	26.12	71,357
2003	86,366.70	37,889	41,844	44,523	26.23	1,697
2004	114,455.34	48,872	53,973	60,482	26.16	2,312
2005	21,018.75	8,710	9,619	11,400	26.14	436
2006	69,562.49	27,881	30,791	38,771	26.17	1,482
2007	23,610.52	9,116	10,068	13,543	26.24	516
2008	35,659.63	13,208	14,587	21,073	26.34	800

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ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2009	2,413.42	857	946	1,467	26.32	56
2010	43,728.67	14,815	16,361	27,367	26.34	1,039
2011	22,599.66	7,288	8,049	14,551	26.26	554
2012	5,648.26	1,722	1,902	3,747	26.23	143
2013	10,825.90	3,092	3,415	7,411	26.26	282
2014	81,905.36	21,787	24,061	57,844	26.21	2,207
2015	2,283.12	559	617	1,666	26.22	64
2016	41,255.41	9,192	10,151	31,104	26.17	1,189
2017	11,058.96	2,207	2,437	8,622	26.07	331
2018	113,373.18	19,829	21,899	91,474	25.95	3,525
2019	931,227.37	137,822	152,207	779,020	25.90	30,078
2020	15,591.87	1,871	2,066	13,526	25.66	527
2021	84,279.77	7,568	8,358	75,922	25.35	2,995
2022	815,637.96	46,328	51,164	764,474	24.89	30,714
	6,256,441.62	2,102,049	2,321,455	3,934,987		152,425
PNG - BLOOMSBURG						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2059						
NET SALVAGE PERCENT.. 0						
1907	12.46	11	12			
1909	57.76	48	53	5	12.86	
1910	136.78	114	126	11	13.13	1
1912	15.65	13	14	1	13.68	
1915	2,677.72	2,192	2,421	257	14.51	18
1930	25,467.58	19,488	21,522	3,946	18.67	211
1933	41.56	31	34	7	19.51	
1934	68.83	52	57	11	19.78	1
1944	71.26	51	56	15	22.52	1
1968	646.66	392	433	214	28.31	8
1974	842.24	483	533	309	29.45	10
1976	103,603.50	58,336	64,425	39,179	29.79	1,315
1977	20,984.75	11,695	12,916	8,069	29.96	269
1978	83.39	46	51	33	30.12	1
1980	1,544.84	834	921	624	30.44	20
1981	984.45	525	580	405	30.59	13
1983	3,281.25	1,914	2,114	1,167	28.94	40
1984	4,173.75	2,391	2,641	1,533	29.46	52

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - BLOOMSBURG						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2059						
NET SALVAGE PERCENT.. 0						
1987	1,513.65	834	921	593	29.72	20
1988	13,483.87	7,324	8,088	5,395	29.86	181
1991	1,061.00	552	610	451	30.00	15
1996	7,009.14	3,315	3,661	3,348	30.64	109
1998	26,471.23	12,015	13,269	13,202	30.68	430
2000	16,127.75	6,974	7,702	8,426	30.85	273
2001	5,503.51	2,316	2,558	2,946	30.97	95
2003	14,245.64	5,665	6,256	7,989	31.05	257
2007	20,621.98	7,110	7,852	12,770	31.35	407
2008	5,631.08	1,868	2,063	3,568	31.23	114
2010	19,035.29	5,730	6,328	12,707	31.35	405
2011	187,198.19	53,351	58,920	128,279	31.36	4,091
2014	780,161.32	181,622	200,579	579,582	31.31	18,511
2015	32,204.52	6,898	7,618	24,587	31.18	789
2016	12,899.16	2,505	2,766	10,133	31.11	326
2018	55,602.72	8,407	9,284	46,318	30.87	1,500
2019	14,930.36	1,908	2,107	12,823	30.71	418
	1,378,394.84	407,010	449,492	928,903		29,901
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1971	255,515.71	215,975	238,518	16,998	6.19	2,746
1972	1,409.73	1,180	1,303	107	6.51	16
1973	1,337.89	1,109	1,225	113	6.84	17
1974	12,848.65	10,539	11,639	1,210	7.19	168
1975	136,871.91	111,072	122,665	14,207	7.54	1,884
1976	266,384.42	213,773	236,086	30,298	7.90	3,835
1978	1,690.35	1,324	1,462	228	8.67	26
1983	1,712.01	1,380	1,524	188	9.75	19
1984	8,199.95	6,511	7,191	1,009	10.25	98
1986	1,464.90	1,132	1,250	215	11.04	19
1987	63,125.74	47,925	52,927	10,198	11.58	881
1988	164,648.24	123,322	136,194	28,454	11.90	2,391
1989	18,159.05	13,343	14,736	3,423	12.45	275
1990	3,264.86	2,351	2,596	668	13.01	51
1992	900.75	624	689	212	13.95	15
1994	8,449.62	5,609	6,194	2,255	14.94	151

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ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1995	469.42	305	337	133	15.36	9
1996	2,262.77	1,431	1,580	682	15.98	43
1997	23,086.19	14,253	15,741	7,346	16.42	447
1998	20,598.33	12,396	13,690	6,908	16.87	409
1999	4,954.86	2,889	3,191	1,764	17.52	101
2000	406,485.00	230,233	254,264	152,221	17.99	8,461
2001	15,740.11	8,607	9,505	6,235	18.65	334
2002	130,879.32	69,222	76,447	54,432	19.15	2,842
2003	14,117.80	7,206	7,958	6,160	19.66	313
2004	40,562.57	19,932	22,012	18,550	20.18	919
2005	19,852.65	9,366	10,344	9,509	20.71	459
2007	62,801.52	26,942	29,754	33,047	21.96	1,505
2008	2,269.95	925	1,022	1,248	22.52	55
2009	9,229.31	3,560	3,932	5,298	23.09	229
2010	65,988.32	24,053	26,564	39,425	23.54	1,675
2011	411,376.94	140,362	155,013	256,364	24.13	10,624
2012	83,849.45	26,614	29,392	54,458	24.73	2,202
2014	113,745.30	30,688	33,891	79,854	25.71	3,106
2015	183,475.30	44,915	49,603	133,872	26.22	5,106
2016	68,250.12	14,947	16,507	51,743	26.75	1,934
2017	316,466.69	61,078	67,453	249,014	27.17	9,165
2018	369,132.11	61,313	67,713	301,419	27.61	10,917
2019	368,538.14	51,079	56,410	312,128	27.97	11,159
2020	667,264.87	73,799	81,502	585,763	28.15	20,809
2021	1,438,049.62	116,770	128,958	1,309,092	28.27	46,307
2022	806,054.82	40,948	45,222	760,833	28.00	27,173
2023	80,338.76	1,494	1,650	78,689	26.45	2,975
	6,671,824.02	1,852,496	2,045,854	4,625,970		181,870
CPG - STROUDSBURG DISTRICT OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. 0						
1970	2,405.60	2,005	2,406			
1971	856.40	712	855	1	9.30	
1977	337.88	275	330	7	9.37	1
1989	1,796.89	1,413	1,698	99	9.36	11
1991	11,012.42	8,518	10,235	778	9.52	82
1993	1,815.54	1,384	1,663	153	9.50	16

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - STROUDSBURG DISTRICT OFFICE INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2033 NET SALVAGE PERCENT.. 0						
1994	163,361.24	123,860	148,821	14,540	9.41	1,545
1995	8,885.02	6,660	8,002	883	9.52	93
1996	549.62	408	490	59	9.54	6
1997	6,779.59	4,995	6,002	778	9.47	82
1998	2,746.90	2,003	2,407	340	9.47	36
2000	60,363.60	42,979	51,641	8,723	9.50	918
2005	3,322.01	2,194	2,636	686	9.51	72
2006	4,194.08	2,716	3,263	931	9.53	98
2008	48,795.58	30,253	36,350	12,446	9.50	1,310
2010	2,580.94	1,512	1,817	764	9.54	80
2011	12,737.88	7,229	8,686	4,052	9.53	425
2015	136,006.52	64,168	77,100	58,907	9.52	6,188
2016	124,033.08	54,599	65,602	58,431	9.54	6,125
2017	98,192.15	39,827	47,853	50,339	9.53	5,282
2018	17,582.52	6,440	7,738	9,845	9.52	1,034
2021	55,041.79	11,504	13,822	41,219	9.46	4,357
2022	37,576.07	5,170	6,212	31,364	9.40	3,337
	800,973.32	420,824	505,629	295,344		31,098
CPG - PORT ALLEGANY OPERATIONS CENTER INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2042 NET SALVAGE PERCENT.. 0						
1990	97.48	64	77	21	17.52	1
1993	722,446.56	458,320	550,681	171,765	17.58	9,770
1994	3,007.87	1,890	2,271	737	17.45	42
1995	8,299.43	5,132	6,166	2,133	17.59	121
1996	2,596.50	1,585	1,904	692	17.55	39
1997	9,570.48	5,758	6,918	2,652	17.55	151
1999	1,682.45	977	1,174	509	17.70	29
2001	408,163.44	228,653	274,731	133,432	17.66	7,556
2003	83,825.01	45,022	54,095	29,730	17.67	1,683
2004	10,415.23	5,464	6,565	3,850	17.67	218
2005	31,960.10	16,319	19,608	12,352	17.73	697
2007	33,654.67	16,215	19,483	14,172	17.75	798
2009	25,242.59	11,347	13,634	11,609	17.76	654
2010	22,431.55	9,690	11,643	10,789	17.75	608
2011	16,615.12	6,875	8,260	8,355	17.71	472

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - PORT ALLEGANY OPERATIONS CENTER						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
2012	2,355.97	927	1,114	1,242	17.74	70
2013	4,094.96	1,522	1,829	2,266	17.75	128
2014	18,455.86	6,434	7,731	10,725	17.75	604
2015	134,792.97	43,767	52,587	82,206	17.68	4,650
2016	10,209.86	3,040	3,653	6,557	17.69	371
2018	11,797.08	2,803	3,368	8,429	17.65	478
2019	5,748.00	1,171	1,407	4,341	17.58	247
2020	32,004.34	5,332	6,407	25,598	17.51	1,462
2021	4,184.24	526	632	3,552	17.38	204
2022	321,717.57	25,866	31,079	290,639	17.16	16,937
2023	265,770.57	7,814	9,389	256,382	16.48	15,557
	2,191,139.90	912,513	1,096,404	1,094,736		63,547
CPG - POTTSVILLE METER SHOP						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. 0						
1937	1,234.84	955	1,147	87	17.55	5
1961	294.42	206	248	47	21.16	2
1970	377.45	250	300	77	22.16	3
1976	1,808.65	1,150	1,382	427	22.71	19
1982	26,509.40	17,162	20,620	5,889	22.60	261
1987	357.42	220	264	93	22.67	4
1988	95.00	58	70	25	22.98	1
1989	24.29	15	18	6	22.97	
1990	2,123.00	1,259	1,513	610	22.99	27
1992	4,760.80	2,744	3,297	1,464	23.15	63
1993	2,703.40	1,534	1,843	860	23.26	37
1995	18,973.34	10,435	12,538	6,435	23.32	276
1996	4,307.22	2,334	2,804	1,503	23.26	65
1997	9,271.45	4,938	5,933	3,338	23.25	144
1998	11,191.78	5,851	7,030	4,162	23.28	179
2000	519,130.02	259,876	312,246	206,884	23.45	8,822
2001	12,387.00	6,076	7,300	5,087	23.37	218
2002	2,306.86	1,101	1,323	984	23.55	42
2004	6,184.42	2,810	3,376	2,808	23.42	120

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - POTTSVILLE METER SHOP						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. 0						
2009	184,472.34	70,358	84,537	99,936	23.52	4,249
2014	17,931.59	5,161	6,201	11,731	23.50	499
2017	149,837.36	32,530	39,085	110,752	23.44	4,725
	976,282.05	427,023	513,077	463,205		19,761
CPG - LEHIGHTON OPERATIONS CENTER						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 8-2073						
NET SALVAGE PERCENT.. 0						
2022	150,681.29	6,027	7,242	143,440	35.96	3,989
2023	2,134,652.00	32,020	38,472	2,096,180	32.94	63,636
	2,285,333.29	38,047	45,714	2,239,619		67,625
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1947	83.04	83	83			
1949	60.87	61	61			
1950	1,717.03	1,708	1,717			
1954	80.73	78	81			
1955	2,484.53	2,391	2,485			
1959	8,364.97	7,815	8,365			
1960	22,868.83	21,199	22,869			
1961	1,330.30	1,224	1,330			
1962	1,109.43	1,012	1,109			
1963	524.00	474	524			
1964	642.99	577	643			
1965	748.08	666	748			
1966	1,360.54	1,202	1,361			
1967	92,432.27	80,971	92,432			
1968	21,209.32	18,420	21,209			
1969	4,153.20	3,576	4,153			
1970	1,809.55	1,544	1,810			
1971	1,825.69	1,543	1,826			
1972	3,903.39	3,268	3,903			
1973	2,545.74	2,110	2,542	3	6.84	

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1974	3,011.77	2,470	2,976	36	7.19	5
1975	11,918.69	9,672	11,654	265	7.54	35
1977	455.40	361	435	20	8.28	2
1978	3,450.00	2,702	3,256	194	8.67	22
1979	399.58	309	372	27	9.07	3
1980	1,239.02	945	1,139	100	9.49	11
1981	3,822.25	2,874	3,463	359	9.92	36
1982	4,395.85	3,576	4,309	87	9.52	9
1983	10,901.68	8,787	10,587	314	9.75	32
1984	479.14	380	458	21	10.25	2
1985	12,331.16	9,638	11,613	718	10.76	67
1986	985.02	761	917	68	11.04	6
1988	1,723.95	1,291	1,556	168	11.90	14
1989	13,431.36	9,869	11,891	1,540	12.45	124
1990	1,460.55	1,052	1,268	193	13.01	15
1991	229,969.08	162,933	196,316	33,653	13.37	2,517
1992	43,448.92	30,110	36,279	7,170	13.95	514
1993	17,597.29	11,970	14,423	3,175	14.34	221
1994	110,317.04	73,228	88,232	22,085	14.94	1,478
1995	120,669.26	78,411	94,477	26,193	15.36	1,705
1996	38,278.82	24,211	29,172	9,107	15.98	570
1997	704,714.66	435,091	524,236	180,478	16.42	10,991
1998	242,060.28	145,672	175,519	66,542	16.87	3,944
1999	273,122.80	159,258	191,888	81,235	17.52	4,637
2000	43,644.74	24,720	29,785	13,860	17.99	770
2001	176,444.05	96,480	116,248	60,196	18.65	3,228
2002	89,209.26	47,183	56,850	32,359	19.15	1,690
2003	33,396.16	17,045	20,537	12,859	19.66	654
2004	721,110.55	354,354	426,957	294,153	20.18	14,576
2005	693,161.48	327,034	394,040	299,122	20.71	14,443
2006	225,801.97	101,566	122,376	103,426	21.41	4,831
2007	123,787.49	53,105	63,986	59,802	21.96	2,723
2008	646,870.10	263,664	317,686	329,184	22.52	14,617
2009	317,730.37	122,549	147,658	170,072	23.09	7,366
2010	121,350.49	44,232	53,295	68,056	23.54	2,891
2011	81,222.16	27,713	33,391	47,831	24.13	1,982
2012	15,266.21	4,845	5,838	9,429	24.73	381
2013	152,321.92	44,783	53,959	98,363	25.21	3,902
2014	185,281.62	49,989	60,231	125,050	25.71	4,864
2015	350,494.98	85,801	103,381	247,114	26.22	9,425
2016	260,140.08	56,971	68,644	191,496	26.75	7,159
2017	93,693.59	18,083	21,788	71,906	27.17	2,647

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
2018	297,431.95	49,403	59,525	237,907	27.61	8,617
2019	199,188.88	27,608	33,265	165,924	27.97	5,932
2020	786,002.66	86,932	104,743	681,259	28.15	24,201
2021	806,801.53	65,512	78,935	727,867	28.27	25,747
2022	1,610,727.18	81,825	98,590	1,512,137	28.00	54,005
2023	230,940.71	4,295	5,175	225,766	26.45	8,536
	10,281,458.20	3,381,185	4,062,565	6,218,893		252,147
	131,977,661.49	41,954,408	44,037,136	87,940,526		4,731,811

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.6 3.59

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	19,545.79	19,057	13,995	5,550	0.50	5,550
2005	12,973.40	12,000	8,813	4,161	1.50	2,774
2006	15,741.19	13,774	10,116	5,626	2.50	2,250
2007	98,862.25	81,561	59,898	38,964	3.50	11,133
2008	10,904.48	8,451	6,206	4,698	4.50	1,044
2009	196,763.79	142,654	104,765	91,999	5.50	16,727
2010	29,674.64	20,030	14,710	14,965	6.50	2,302
2013	49,177.44	25,818	18,961	30,217	9.50	3,181
2014	164,928.32	78,341	57,533	107,395	10.50	10,228
2015	142,233.63	60,449	44,394	97,840	11.50	8,508
2016	156,448.43	58,668	43,086	113,363	12.50	9,069
2017	694,772.06	225,801	165,828	528,944	13.50	39,181
2018	365,293.03	100,456	73,775	291,518	14.50	20,105
2019	260,157.81	58,536	42,989	217,169	15.50	14,011
2020	235,363.22	41,189	30,249	205,114	16.50	12,431
2021	186,194.50	23,274	17,092	169,102	17.50	9,663
2022	239,796.94	17,985	13,208	226,589	18.50	12,248
2023	200,000.00	5,000	3,672	196,328	19.50	10,068
	3,078,830.92	993,044	729,289	2,349,542		190,473
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	826.89	806	802	25	0.50	25
2005	1,086.91	1,005	1,000	87	1.50	58
2006	1,234.22	1,080	1,074	160	2.50	64
2007	1,312.22	1,083	1,077	235	3.50	67
2008	24,417.03	18,923	18,822	5,595	4.50	1,243
2010	2,239.24	1,511	1,503	736	6.50	113
2011	20,678.25	12,924	12,855	7,823	7.50	1,043
2014	33,759.66	16,036	15,950	17,809	10.50	1,696
2015	35,177.20	14,950	14,870	20,307	11.50	1,766
2016	233,275.70	87,478	87,011	146,265	12.50	11,701
2017	400,100.57	130,033	129,339	270,762	13.50	20,056
2018	31,187.62	8,577	8,531	22,656	14.50	1,562
2019	69,735.23	15,690	15,606	54,129	15.50	3,492
2020	115,739.37	20,254	20,146	95,593	16.50	5,794

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	61,990.92	7,749	7,708	54,283	17.50	3,102
2022	50,000.00	3,750	3,730	46,270	18.50	2,501
2023	50,000.00	1,250	1,243	48,757	19.50	2,500
	1,132,761.03	343,099	341,268	791,493		56,783
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	11,966.55	11,667	11,369	597	0.50	597
2006	1,393.32	1,219	1,188	205	2.50	82
2007	4,828.41	3,983	3,881	947	3.50	271
2010	1,926.82	1,301	1,268	659	6.50	101
2014	4,225.61	2,007	1,956	2,270	10.50	216
2015	64,028.79	27,212	26,518	37,511	11.50	3,262
2016	22,950.78	8,607	8,387	14,563	12.50	1,165
2017	29,884.80	9,713	9,465	20,420	13.50	1,513
2018	66,579.64	18,309	17,842	48,738	14.50	3,361
2019	9,728.37	2,189	2,133	7,595	15.50	490
2020	395,875.29	69,278	67,510	328,365	16.50	19,901
2021	17,352.44	2,169	2,114	15,239	17.50	871
2022	110,598.61	8,295	8,083	102,515	18.50	5,541
2023	100,000.00	2,500	2,436	97,564	19.50	5,003
	841,339.43	168,449	164,151	677,188		42,374
	5,052,931.38	1,504,592	1,234,708	3,818,223		289,630

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.2   5.73

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	4,313.90	3,667	3,816	498	1.50	332
2016	42,502.55	31,877	33,175	9,328	2.50	3,731
2017	3,747.59	2,436	2,535	1,212	3.50	346
2020	18,196.00	6,369	6,628	11,568	6.50	1,780
2021	30,929.53	7,732	8,047	22,883	7.50	3,051
	99,689.57	52,081	54,201	45,489		9,240
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	7,913.29	6,726	6,404	1,509	1.50	1,006
2016	5,541.48	4,156	3,957	1,584	2.50	634
2017	8,554.22	5,560	5,294	3,260	3.50	931
2018	2,800.72	1,540	1,466	1,334	4.50	296
2021	67,496.24	16,874	16,067	51,430	7.50	6,857
	92,305.95	34,856	33,188	59,118		9,724
	191,995.52	86,937	87,389	104,607		18,964

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5 9.88

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS SURVIVOR CURVE.. 5-SQUARE NET SALVAGE PERCENT.. 0						
2021	20,690.72	10,345	9,196	11,495	2.50	4,598
	20,690.72	10,345	9,196	11,495		4,598
PNG SURVIVOR CURVE.. 5-SQUARE NET SALVAGE PERCENT.. 0						
2021	46,130.82	23,065	13,735-	59,866	2.50	23,946
	46,130.82	23,065	13,735-	59,866		23,946
CPG SURVIVOR CURVE.. 5-SQUARE NET SALVAGE PERCENT.. 0						
2021	20,690.76	10,345	12,631-	33,322	2.50	13,329
	20,690.76	10,345	12,631-	33,322		13,329
	87,512.30	43,755	17,170-	104,683		41,873

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.5 47.85

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2020	739,692.50	352,833	371,298	368,394	3.84	95,936
2021	1,110,006.13	394,274	414,908	695,098	4.54	153,105
2022	544,961.77	119,892	126,166	418,795	5.32	78,721
2023	339,434.68	25,390	26,719	312,716	6.18	50,601
	2,734,095.08	892,389	939,091	1,795,004		378,363
PNG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2018	218,583.42	144,505	136,727	81,857	2.82	29,027
2020	79,100.31	37,731	35,700	43,400	3.84	11,302
2022	307,641.27	67,681	64,038	243,603	5.32	45,790
2023	242,549.43	18,143	17,166	225,383	6.18	36,470
	847,874.43	268,060	253,631	594,243		122,589
CPG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2019	34,454.25	19,983	16,370	18,084	3.26	5,547
2020	56,212.10	26,813	21,966	34,246	3.84	8,918
2021	82,000.10	29,126	23,861	58,140	4.54	12,806
2022	250,333.37	55,073	45,117	205,216	5.32	38,574
2023	454,408.30	33,990	27,845	426,563	6.18	69,023
	877,408.12	164,985	135,159	742,249		134,868
	4,459,377.63	1,325,434	1,327,881	3,131,496		635,820

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.9   14.26

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	103,951.73	72,039	71,551	32,401	3.32	9,759
2018	960,166.13	548,159	544,447	415,719	4.13	100,658
2019	458,414.33	223,798	222,282	236,132	4.72	50,028
2020	4,508,370.11	1,773,593	1,761,582	2,746,788	5.40	508,664
2021	710,416.44	205,452	204,061	506,356	6.14	82,468
2022	4,071,384.72	721,857	716,968	3,354,416	6.96	481,956
2023	2,533,248.22	151,488	150,462	2,382,786	7.85	303,540
	13,345,951.68	3,696,386	3,671,353	9,674,599		1,537,073
PNG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	528,244.46	366,073	344,448	183,797	3.32	55,361
2018	519,183.28	296,402	278,892	240,291	4.13	58,182
2019	1,581,394.11	772,037	726,430	854,964	4.72	181,136
2020	3,496,735.67	1,375,616	1,294,353	2,202,382	5.40	407,849
2021	732,398.24	211,810	199,298	533,101	6.14	86,824
2022	2,298,977.01	407,609	383,530	1,915,447	6.96	275,208
2023	1,810,201.86	108,250	101,855	1,708,347	7.85	217,624
	10,967,134.63	3,537,797	3,328,806	7,638,329		1,282,184
CPG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2009	11,512.06	9,982	9,489	2,023	2.22	911
2010	3,490.09	2,964	2,818	673	2.40	280
2019	1,200,984.83	586,321	557,352	643,633	4.72	136,363
2020	3,055,255.22	1,201,937	1,142,552	1,912,704	5.40	354,204
2021	452,270.68	130,797	124,335	327,936	6.14	53,410
2022	1,902,043.84	337,232	320,570	1,581,474	6.96	227,223
2023	3,392,890.30	202,895	192,870	3,200,020	7.85	407,646
	10,018,447.02	2,472,128	2,349,985	7,668,462		1,180,037
	34,331,533.33	9,706,311	9,350,144	24,981,390		3,999,294

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.2   11.65

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2019	35,491.71	14,630	2,433	33,059	6.42	5,149
2022	395,523.28	55,927	9,301	386,223	9.10	42,442
2023	247,819.38	11,697	1,945	245,874	10.09	24,368
	678,834.37	82,254	13,679	665,155		71,959
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	401,841.19	198,469	176,717	225,124	5.64	39,916
2020	461,508.78	150,221	133,757	327,752	7.25	45,207
2022	225,283.96	31,855	28,364	196,920	9.10	21,640
2023	177,081.00	8,358	7,442	169,639	10.09	16,813
	1,265,714.93	388,903	346,280	919,435		123,576
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2004	121,413.98	111,507	117,685	3,729	1.73	2,155
2005	69,521.56	62,889	66,373	3,148	1.95	1,614
2006	172,475.34	153,331	161,826	10,649	2.19	4,863
2019	602,398.92	248,309	262,066	340,332	6.42	53,011
2020	491,552.36	160,000	168,865	322,688	7.25	44,509
2022	187,036.61	26,447	27,912	159,124	9.10	17,486
2023	331,937.00	15,667	16,535	315,402	10.09	31,259
	1,976,335.77	778,150	821,263	1,155,073		154,897
	3,920,885.07	1,249,307	1,181,222	2,739,663		350,432

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.8 8.94

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	403,560.63	199,319	218,156	185,404	5.64	32,873
2019	345,379.32	142,365	155,820	189,560	6.42	29,526
2020	490,460.78	159,645	174,733	315,728	7.25	43,549
2021	306,144.91	71,883	78,677	227,468	8.15	27,910
2022	622,825.25	88,067	96,390	526,435	9.10	57,850
2023	386,373.00	18,237	19,961	366,412	10.09	36,314
	2,554,743.89	679,516	743,736	1,811,008		228,022
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	342,626.00	169,223	146,276	196,350	5.64	34,814
2019	290,458.76	119,727	103,491	186,967	6.42	29,123
2020	337,021.24	109,700	94,824	242,197	7.25	33,406
2022	351,206.30	49,661	42,927	308,280	9.10	33,877
2023	276,083.00	13,031	11,264	264,819	10.09	26,246
	1,597,395.30	461,342	398,782	1,198,613		157,466
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2001	34,828.72	33,227	34,829			
2002	50,124.09	47,202	49,763	361	1.33	271
2005	195,085.29	176,474	186,047	9,038	1.95	4,635
2019	303,937.59	125,283	132,079	171,858	6.42	26,769
2020	513,765.32	167,231	176,303	337,462	7.25	46,546
2022	291,604.11	41,233	43,470	248,134	9.10	27,267
2023	517,516.00	24,427	25,752	491,764	10.09	48,738
	1,906,861.12	615,077	648,243	1,258,618		154,226
	6,059,000.31	1,755,935	1,790,761	4,268,239		539,714

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.9   8.91

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2012	10,716.56	7,259	7,051	3,666	5.48	669
2016	254,717.26	135,255	131,372	123,346	6.62	18,632
2019	25,125.61	8,809	8,556	16,570	8.34	1,987
2022	260,938.88	32,617	31,681	229,258	10.50	21,834
2023	162,107.27	6,825	6,629	155,478	11.38	13,662
	713,605.58	190,765	185,288	528,318		56,784
PNG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1998	512.74	459	431	82	2.99	27
2004	515.28	424	398	117	4.20	28
2011	31,925.78	22,428	21,057	10,868	5.29	2,054
2018	70,027.63	29,195	27,411	42,617	7.69	5,542
2020	292,987.92	81,919	76,913	216,075	9.02	23,955
2021	334,581.76	68,422	64,241	270,341	9.72	27,813
2022	147,089.20	18,386	17,262	129,827	10.50	12,364
2023	115,832.56	4,877	4,579	111,254	11.38	9,776
	993,472.87	226,110	212,292	781,181		81,559
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1994	1,906.00	1,771	1,881	25	2.25	11
2001	30,872.14	26,606	28,255	2,617	3.61	725
2002	4,805.72	4,081	4,334	472	3.82	124
2003	14,017.08	11,724	12,451	1,567	4.01	391
2004	34,730.50	28,580	30,351	4,379	4.20	1,043
2005	144,584.18	116,882	124,125	20,459	4.38	4,671
2006	17,170.56	13,613	14,457	2,714	4.57	594
2009	11,228.82	8,352	8,870	2,359	4.99	473
2017	6,935.21	3,309	3,514	3,421	7.12	480
2019	68,843.21	24,136	25,632	43,211	8.34	5,181
2020	139,747.77	39,073	41,494	98,253	9.02	10,893

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2021	246,513.61	50,412	53,536	192,977	9.72	19,854
2022	122,284.53	15,286	16,233	106,051	10.50	10,100
2023	217,137.77	9,142	9,709	207,429	11.38	18,228
	1,060,777.10	352,967	374,841	685,936		72,768
	2,767,855.55	769,842	772,421	1,995,435		211,111

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.5 7.63

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG SURVIVOR CURVE.. 20-SQUARE NET SALVAGE PERCENT.. 0						
2004	1,768.11	1,724	1,726	42	0.50	42
	1,768.11	1,724	1,726	42		42
CPG SURVIVOR CURVE.. 20-SQUARE NET SALVAGE PERCENT.. 0						
2014	5,589.99	2,655	2,655	2,935	10.50	280
2018	10,248.45	2,818	2,818	7,430	14.50	512
	15,838.44	5,473	5,473	10,365		792
	17,606.55	7,197	7,199	10,407		834

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.5   4.74

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	376,497.34	367,085	369,767	6,730	0.50	6,730
2005	585,131.98	541,247	545,202	39,930	1.50	26,620
2006	533,535.20	466,843	470,254	63,281	2.50	25,312
2007	637,237.38	525,721	529,562	107,675	3.50	30,764
2008	236,121.16	182,994	184,331	51,790	4.50	11,509
2009	267,438.49	193,893	195,310	72,129	5.50	13,114
2010	162,964.81	110,001	110,805	52,160	6.50	8,025
2011	451,363.00	282,102	284,163	167,200	7.50	22,293
2012	368,654.37	211,976	213,525	155,130	8.50	18,251
2013	792,113.30	415,859	418,897	373,216	9.50	39,286
2014	476,076.46	226,136	227,788	248,288	10.50	23,646
2015	1,648,297.12	700,526	705,644	942,653	11.50	81,970
2016	1,270,294.92	476,361	479,842	790,453	12.50	63,236
2017	1,830,420.92	594,887	599,234	1,231,187	13.50	91,199
2018	915,728.07	251,825	253,665	662,063	14.50	45,660
2019	1,013,890.01	228,125	229,792	784,098	15.50	50,587
2020	1,692,662.34	296,216	298,380	1,394,282	16.50	84,502
2021	1,785,140.52	223,143	224,773	1,560,367	17.50	89,164
2022	2,220,574.48	166,543	167,760	2,052,815	18.50	110,963
2023	1,231,857.00	30,796	31,021	1,200,836	19.50	61,581
	18,495,998.87	6,492,279	6,539,715	11,956,284		904,412
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	270,994.91	264,220	263,620	7,375	0.50	7,375
2005	107,276.26	99,231	99,006	8,271	1.50	5,514
2006	272,070.63	238,062	237,521	34,549	2.50	13,820
2007	397,958.98	328,316	327,571	70,388	3.50	20,111
2008	194,881.81	151,033	150,690	44,192	4.50	9,820
2009	386,652.36	280,323	279,687	106,966	5.50	19,448
2010	528,508.76	356,743	355,933	172,576	6.50	26,550
2011	46,412.17	29,008	28,942	17,470	7.50	2,329
2012	106,370.79	61,163	61,024	45,347	8.50	5,335
2013	245,409.98	128,840	128,547	116,863	9.50	12,301
2014	495,061.18	235,154	234,620	260,441	10.50	24,804
2015	960,119.93	408,051	407,125	552,995	11.50	48,087
2016	582,263.35	218,349	217,853	364,410	12.50	29,153
2017	608,859.13	197,879	197,430	411,429	13.50	30,476

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	1,012,779.35	278,514	277,882	734,898	14.50	50,683
2019	536,030.46	120,607	120,333	415,697	15.50	26,819
2020	1,296,129.90	226,823	226,308	1,069,822	16.50	64,838
2021	1,226,021.61	153,253	152,905	1,073,117	17.50	61,321
2022	1,470,338.24	110,275	110,025	1,360,314	18.50	73,530
2023	1,417,177.00	35,429	35,349	1,381,828	19.50	70,863
	12,161,316.80	3,921,273	3,912,370	8,248,947		603,177
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	403,566.38	393,477	359,386	44,180	0.50	44,180
2005	471,228.17	435,886	398,121	73,107	1.50	48,738
2006	277,067.07	242,434	221,430	55,637	2.50	22,255
2007	507,181.09	418,424	382,172	125,009	3.50	35,717
2008	544,153.86	421,719	385,181	158,972	4.50	35,327
2009	190,844.18	138,362	126,374	64,470	5.50	11,722
2010	675,112.97	455,701	416,219	258,894	6.50	39,830
2011	41,307.18	25,817	23,580	17,727	7.50	2,364
2012	185,811.11	106,841	97,584	88,227	8.50	10,380
2013	268,626.03	141,029	128,810	139,816	9.50	14,717
2014	510,814.37	242,637	221,615	289,199	10.50	27,543
2015	362,285.21	153,971	140,631	221,654	11.50	19,274
2016	632,442.31	237,166	216,618	415,824	12.50	33,266
2017	243,698.39	79,202	72,340	171,358	13.50	12,693
2018	534,429.05	146,968	134,235	400,194	14.50	27,600
2019	795,631.49	179,017	163,507	632,124	15.50	40,782
2020	463,388.36	81,093	74,067	389,321	16.50	23,595
2021	934,658.67	116,832	106,710	827,949	17.50	47,311
2022	782,352.30	58,676	53,592	728,760	18.50	39,392
2023	717,692.00	17,942	16,388	701,304	19.50	35,964
	9,542,290.19	4,093,194	3,738,561	5,803,729		572,650
	40,199,605.86	14,506,746	14,190,646	26,008,960		2,080,239

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.5   5.17

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	552.73	235	230	323	11.50	28
2016	1,085.72	407	399	687	12.50	55
2017	330,397.55	107,379	105,152	225,245	13.50	16,685
2018	105,742.64	29,079	28,476	77,267	14.50	5,329
	437,778.64	137,100	134,257	303,522		22,097

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.7 5.05

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2000	6,498.36	5,681	6,226	273	3.38	81
2001	30,317.91	26,128	28,633	1,685	3.61	467
2002	3,719.59	3,159	3,462	258	3.82	68
2003	35,492.23	29,686	32,532	2,960	4.01	738
2004	54,943.24	45,213	49,548	5,395	4.20	1,285
2005	14,736.28	11,913	13,055	1,681	4.38	384
2006	28,808.32	22,839	25,029	3,779	4.57	827
2007	37,931.66	29,480	32,307	5,625	4.73	1,189
2009	64,652.45	48,088	52,699	11,954	4.99	2,396
2013	15,373.86	9,993	10,951	4,423	5.65	783
2018	220,480.47	91,918	100,731	119,749	7.69	15,572
2019	308,929.87	108,311	118,696	190,234	8.34	22,810
2020	1,614,013.94	451,278	494,549	1,119,465	9.02	124,109
2021	76,359.04	15,615	17,112	59,247	9.72	6,095
	2,512,257.22	899,302	985,531	1,526,726		176,804
PNG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2003	68,109.74	56,967	66,598	1,511	4.01	377
2004	167,248.57	137,629	160,898	6,351	4.20	1,512
2007	13,369.18	10,391	12,148	1,221	4.73	258
2008	35,075.31	26,692	31,205	3,870	4.87	795
2009	48,114.46	35,788	41,839	6,276	4.99	1,258
2010	12,089.03	8,748	10,227	1,862	5.16	361
2018	1,346,981.57	561,557	656,500	690,482	7.69	89,790
2020	783,198.88	218,982	256,005	527,193	9.02	58,447
2021	45,428.50	9,290	10,861	34,568	9.72	3,556
	2,519,615.24	1,066,044	1,246,281	1,273,334		156,354
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2001	21,592.29	18,608	17,235	4,357	3.61	1,207
2002	30,786.38	26,144	24,215	6,571	3.82	1,720
2003	50,494.67	42,234	39,118	11,377	4.01	2,837
2004	106,224.95	87,413	80,963	25,262	4.20	6,015

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2005	199,925.67	161,620	149,695	50,231	4.38	11,468
2006	32,646.90	25,882	23,972	8,675	4.57	1,898
2009	69,039.30	51,351	47,562	21,477	4.99	4,304
2018	909.08	379	351	558	7.69	73
2019	106,125.88	37,208	34,463	71,663	8.34	8,593
2020	920,993.58	257,510	238,509	682,484	9.02	75,663
	1,538,738.70	708,349	656,083	882,656		113,778
	6,570,611.16	2,673,695	2,887,895	3,682,716		446,936

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.2 6.80

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	40,712.05	10,178	7,659	33,053	7.50	4,407
	40,712.05	10,178	7,659	33,053		4,407
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	713,351.62	463,679	393,764	319,587	3.50	91,311
2019	33,841.70	15,229	12,933	20,909	5.50	3,802
2021	50,379.19	12,595	10,696	39,683	7.50	5,291
	797,572.51	491,503	417,393	380,180		100,404
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	151.47	144	151			
2015	28,671.36	24,371	28,671			
2017	17,961.49	11,675	17,039	923	3.50	264
2021	21,890.53	5,473	7,987	13,903	7.50	1,854
	68,674.85	41,663	53,849	14,826		2,118
	906,959.41	543,344	478,901	428,059		106,929

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.0 11.79

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	102,456.20	78,550	52,326	50,130	3.50	14,323
2013	51,777.87	36,245	24,145	27,633	4.50	6,141
2014	178,624.07	113,128	75,360	103,264	5.50	18,775
2015	39,471.49	22,367	14,900	24,572	6.50	3,780
2016	32,235.43	16,118	10,737	21,498	7.50	2,866
2017	165,977.94	71,923	47,912	118,066	8.50	13,890
2018	106,282.35	38,971	25,961	80,322	9.50	8,455
2020	146,222.17	34,118	22,728	123,494	11.50	10,739
2022	59,425.00	5,942	3,958	55,467	13.50	4,109
	882,472.52	417,362	278,026	604,447		83,078
PNG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	72,298.45	69,889	68,796	3,502	0.50	3,502
2010	346,189.24	311,570	306,698	39,491	1.50	26,327
2011	26,672.91	22,227	21,879	4,793	2.50	1,917
2012	6,969.59	5,343	5,259	1,710	3.50	489
2014	262,109.02	166,002	163,406	98,703	5.50	17,946
2016	184,658.73	92,329	90,885	93,773	7.50	12,503
2017	64,069.97	27,763	27,329	36,741	8.50	4,322
2018	1,869.95	686	675	1,195	9.50	126
2020	61,699.27	14,396	14,171	47,528	11.50	4,133
2022	89,137.51	8,914	8,775	80,363	13.50	5,953
	1,115,674.64	719,119	707,875	407,800		77,218
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	19,072.92	18,437	17,841	1,232	0.50	1,232
2010	46,085.64	41,477	40,136	5,949	1.50	3,966
2011	70,068.25	58,390	56,503	13,565	2.50	5,426
2012	14,758.99	11,315	10,949	3,810	3.50	1,089
2014	2,414.03	1,529	1,480	934	5.50	170
2015	4,956.48	2,809	2,718	2,238	6.50	344
2016	65,279.25	32,640	31,585	33,694	7.50	4,493
2017	81,771.73	35,434	34,289	47,483	8.50	5,586

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	4,477.95	1,642	1,589	2,889	9.50	304
2019	1,267.76	380	368	900	10.50	86
2020	4,259.10	994	962	3,297	11.50	287
2022	29,712.49	2,971	2,875	26,838	13.50	1,988
	344,124.59	208,018	201,295	142,830		24,971
	2,342,271.75	1,344,499	1,187,196	1,155,077		185,267

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.2 7.91

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI HEADQUARTERS BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 1-2069						
NET SALVAGE PERCENT.. 0						
2019	30,037,912.33	3,676,640	3,612,737	26,425,175	32.26	819,131
2020	1,907,500.04	189,606	186,310	1,721,190	31.71	54,279
2021	671,173.69	50,338	49,463	621,711	30.83	20,166
2022	2,123,767.06	102,578	100,795	2,022,972	29.56	68,436
2023	100,454.00	1,878	1,845	98,609	26.24	3,758
	34,840,807.12	4,021,040	3,951,151	30,889,656		965,770

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.0   2.77

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	11,896.38	11,599	10,594	1,302	0.50	1,302
2005	39,965.68	36,968	33,765	6,201	1.50	4,134
2006	2,468.81	2,160	1,973	496	2.50	198
2007	878.14	724	661	217	3.50	62
2008	572.40	444	406	166	4.50	37
2009	4,753.12	3,446	3,147	1,606	5.50	292
2010	747,318.56	504,440	460,740	286,579	6.50	44,089
2019	3,525,485.48	793,234	724,516	2,800,969	15.50	180,708
2020	27,303.10	4,778	4,364	22,939	16.50	1,390
	4,360,641.67	1,357,793	1,240,166	3,120,476		232,212

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.4 5.33

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	277,204.74	249,484	233,477	43,728	0.50	43,728
2021	1,076,384.85	538,192	503,660	572,725	2.50	229,090
	1,353,589.59	787,676	737,137	616,453		272,818

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.3   20.16

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L2.5						
NET SALVAGE PERCENT.. 0						
2004	26,875.84	26,876	26,876			
2008	22,536.44	21,658	22,536			
2014	22,224.80	18,940	22,225			
	71,637.08	67,474	71,637			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	27,967.27	9,789	7,091	20,876	6.50	3,212
	27,967.27	9,789	7,091	20,876		3,212

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5   11.48

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS - NEW READING DATA CENTER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2073						
NET SALVAGE PERCENT.. 0						
2023	4,000,001.00	5,200	5,200	3,994,801	31.50	126,819
	4,000,001.00	5,200	5,200	3,994,801		126,819

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.5   3.17

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	5,698.56	5,556	5,171	528	0.50	528
2007	1,760.05	1,452	1,352	408	3.50	117
	7,458.61	7,008	6,523	936		645

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.5   8.65

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	9,507,270.50	8,556,543	7,978,774	1,528,496	0.50	1,528,496
2020	1,980,934.07	1,386,654	1,293,022	687,912	1.50	458,608
2021	504,089.49	252,045	235,026	269,063	2.50	107,625
	11,992,294.06	10,195,242	9,506,822	2,485,472		2,094,729

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.2 17.47

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SUCCESS FACTORS INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2024 NET SALVAGE PERCENT.. 0						
2019	2,803,866.07	2,294,067	2,076,802	727,064	1.00	727,064
	2,803,866.07	2,294,067	2,076,802	727,064		727,064
UNITE ERP INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2034 NET SALVAGE PERCENT.. 0						
2019	10,695,816.43	3,105,209	2,359,182	8,336,634	11.00	757,876
	10,695,816.43	3,105,209	2,359,182	8,336,634		757,876
	13,499,682.50	5,399,276	4,435,984	9,063,698		1,484,940

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.1 11.00

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	988,604.39	939,174	874,812	113,792	0.50	113,792
2015	732,102.69	622,287	579,641	152,462	1.50	101,641
2016	930,430.13	697,823	650,001	280,429	2.50	112,172
2017	1,349,992.48	877,495	817,360	532,632	3.50	152,181
2018	1,384,581.24	761,520	709,332	675,249	4.50	150,055
2019	7,509,579.44	3,379,311	3,147,724	4,361,855	5.50	793,065
2020	13,110,042.00	4,588,515	4,274,061	8,835,981	6.50	1,359,382
2021	6,971,595.51	1,742,899	1,623,457	5,348,139	7.50	713,085
2022	13,214,700.50	1,982,205	1,846,363	11,368,338	8.50	1,337,452
2023	20,180,262.00	1,009,013	939,865	19,240,397	9.50	2,025,305
	66,371,890.38	16,600,242	15,462,616	50,909,274		6,858,130

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.4   10.33

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2011	425,873.07	354,893	348,918	76,955	2.50	30,782
2012	401,290.13	307,657	302,477	98,813	3.50	28,232
2013	142,364.69	99,655	97,977	44,388	4.50	9,864
2014	495,556.48	313,851	308,567	186,989	5.50	33,998
2016	1,419,264.44	709,632	697,685	721,579	7.50	96,211
2017	76,271,826.62	33,050,871	32,494,439	43,777,388	8.50	5,150,281
2018	171,914.66	63,036	61,975	109,940	9.50	11,573
2019	43,689,680.34	13,106,904	12,886,240	30,803,440	10.50	2,933,661
2021	6,526,337.79	1,087,745	1,069,432	5,456,906	12.50	436,552
2022	1,880,199.40	188,020	184,855	1,695,344	13.50	125,581
	131,424,307.62	49,282,264	48,452,565	82,971,743		8,856,735

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.4 6.74

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS - UNITE ADC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2023

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2023	41,177,032.00	1,372,430	1,945,443	39,231,589	14.50	2,705,627
	41,177,032.00	1,372,430	1,945,443	39,231,589		2,705,627

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.5 6.57

PART IV. EXPERIENCED AND ESTIMATED NET SALVAGE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2019 TRANSACTION YEAR				
369.00		131.00		131.00-
376.00	2,599,001.00	440,534.00	62,338.00	378,196.00-
378.00	159,150.00	154,135.00	15,813.00	138,322.00-
379.00	231,613.00			
380.00	8,211,461.00	3,425,191.00		3,425,191.00-
381.00	1,090,648.00	770.00		770.00-
382.00	72,768.00	262,633.00		262,633.00-
383.00		54,424.00-		54,424.00
384.00		2.00-		2.00
385.00		4,047.00		4,047.00-
390.10		76,973.00		76,973.00-
391.10	461,640.00			
391.20	75,179.00			
391.30	5,022.00			
391.40	3,295,776.00			
393.00	774.00			
394.00	609,662.00			
397.00	111,549.00			
398.00	76,034.00	652.00		652.00-
	17,000,277.00	4,310,640.00	78,151.00	4,232,489.00-
2020 TRANSACTION YEAR				
376.00	6,459,698.00	1,030,068.00		1,030,068.00-
378.00	2,984.00	29,723.00		29,723.00-
380.00	11,637,744.00	4,911,297.00		4,911,297.00-
381.00	904,135.00			
382.00		1,144,545.00		1,144,545.00-
383.00		2,130.00		2,130.00-
384.00		515,427.00		515,427.00-
390.10		17,949.00		17,949.00-
391.10	127,130.00			
391.20	33,245.00			
391.30	174,316.00			
392.00			691,071.00	691,071.00
394.00	808,538.00			
397.00	1,182,932.00			
398.00	54,164.00	257,300.00		257,300.00-
	21,384,886.00	7,908,439.00	691,071.00	7,217,368.00-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2021 TRANSACTION YEAR				
305.00			115,195.00	115,195.00
367.00	24.00	1,660.00		1,660.00-
369.00		3,386.00		3,386.00-
375.00	18,008.00			
376.00	4,504,366.00	2,534,160.00		2,534,160.00-
378.00		168,692.00		168,692.00-
379.00		15,105.00		15,105.00-
380.00	12,500,315.00	4,191,361.00		4,191,361.00-
381.00	3,015,928.00	1,237.00	19,201.00	17,964.00
382.00		224,823.00		224,823.00-
383.00		269.00		269.00-
384.00		13,720.00		13,720.00-
385.00		35,290.00		35,290.00-
386.00	269,143.00			
390.10	231,077.00	135.00		135.00-
391.10	661,188.00			
391.20	74,471.00			
391.30	120,424.00			
392.00			526,894.00	526,894.00
393.00	3,091.00			
394.00	869,872.00			
397.00	8,099.00			
398.00	88,752.00	391,820.00		391,820.00-
	22,364,758.00	7,581,658.00	661,290.00	6,920,368.00-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2022 TRANSACTION YEAR				
376.00	6,206,044.00	2,022,087.00		2,022,087.00-
378.00	3,311,668.00	656,781.00	218,659.00	438,122.00-
380.00	6,926,792.00	3,574,917.00		3,574,917.00-
381.00	1,717,529.00	1,589.00	4,145.00	2,556.00
382.00	561,313.00	289,694.00		289,694.00-
383.00	6,349.00	3,276.00		3,276.00-
384.00	24,046.00	12,410.00		12,410.00-
390.10	657,344.00	65,735.00		65,735.00-
391.10	85,045.00			
391.20	6,467.00			
391.30	356,493.00			
391.40	4,378,298.00			
392.00	2,229,069.00		477,914.00	477,914.00
394.00	684,358.00			
397.00	82,938.00			
398.00	143,552.00			
399.00	16,032.00			
	27,393,337.00	6,626,489.00	700,718.00	5,925,771.00-
2023 TRANSACTION YEAR				
376.00	6,871,683.00	2,143,071.02		2,143,071.02-
378.00	2,678,253.00	531,160.46	176,836.16	354,324.30-
380.00	7,021,602.00	3,623,848.28		3,623,848.28-
381.00	1,534,160.00	1,419.52	3,701.77	2,282.25
382.00	517,857.00	267,265.48		267,265.48-
383.00	6,349.00	3,276.31		3,276.31-
384.00	24,046.00	12,410.31		12,410.31-
390.10	1,663,190.00	166,319.00		166,319.00-
391.10	74,005.00			
391.20	1,638.00			
391.30	575,464.00			
392.00	2,077,805.00		445,481.30	445,481.30
394.00	645,980.00			
397.00	31,838.00			
398.00	48,107.00			
	23,771,977.00	6,748,770.38	626,019.23	6,122,751.15-
TOTAL	111,915,235.00	33,175,996.38	2,757,249.23	30,418,747.15-

BOOK VII

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT C (FUTURE)

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2022

Witness: John F. Wiedmayer
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 Effective: March 29, 2022

UGI Gas Exhibit C (Future)
Witness: J. F. Wiedmayer

UGI UTILITIES, INC. – GAS DIVISION

DOCKET NO. R-2021-3030218

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AT SEPTEMBER 30, 2022

Prepared by:

Gannett Fleming

*Excellence Delivered **As Promised***

UGI UTILITIES, INC. - GAS DIVISION

Docket No. R-2021-3030218

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AT SEPTEMBER 30, 2022

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Valley Forge, Pennsylvania

Gannett Fleming

Excellence Delivered ***As Promised***

January 6, 2022

Mr. Anton R. Hummer
Controller and Principal Accounting Officer
UGI Utilities, Inc. – Gas Division
1 UGI Drive
Denver, PA 17517

Ladies and Gentlemen:

Pursuant to your request, we have determined the annual depreciation accruals applicable to gas plant in service. The results of our study at September 30, 2022 are presented in the attached report labelled as UGI Gas Exhibit C (Future).

The results of our study at September 30, 2021 are presented in our report titled "Depreciation Study- Calculated Annual Depreciation Accruals Related to Gas Plant at September 30, 2021". This report is identified for purposes of this filing as UGI Gas Exhibit C (Historic). The results of our study at September 30, 2023 are presented in our report titled "Depreciation Study- Calculated Annual Depreciation Accruals Related to Gas Plant at September 30, 2023". This report is identified for purposes of this filing as UGI Gas Exhibit C (Fully Projected Future). The same methods, procedures and estimates are used in all three exhibits and test years.

The attached report sets forth a description of the methods and procedures upon which the studies were based, the estimates of survivor curves and the calculated annual depreciation rates at September 30, 2022.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John F. Wiedmayer

JOHN F. WIEDMAYER, C.D.P.
Project Manager, Depreciation Studies

JFW:mle
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PART I. INTRODUCTION

UGI UTILITIES, INC. - GAS DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study conducted for UGI Utilities, Inc. - Gas Division to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of gas plant at September 30, 2022.

The depreciation accrual rates and amounts presented herein are based on estimated survivor curves and on methods and procedures set forth in previous orders approved by the Pennsylvania Public Utility Commission. The estimated survivor curves presented herein were based on the results of a service life study incorporating statistical analyses of data through 2017 for the consolidated UGI gas company. The consolidated gas company includes the former UGI Penn Natural Gas Company (UGI PNG, now UGI North), UGI Central Penn Gas Company (UGI CPG, now UGI Central) and UGI Utilities, Inc. – Gas Division (UGI Gas, now UGI South).

BASIS OF STUDY

Depreciation and Amortization

Depreciation, as defined in the Uniform System of Accounts, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

The calculation of annual and accrued depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. These subjects are discussed in the sections which follow.
For most plant accounts, depreciation accruals and accrued depreciation were calculated using the straight line method, the remaining life basis, the average service life (ASL) procedure for plant installed prior to 1982 and the equal life group (ELG) procedure for 1982 and subsequent vintages. The calculations were based on the attained ages and estimated service life characteristics for each depreciable group of gas property. For certain general plant accounts, the amortization amounts, annual and accrued, were based on the age of the vintage and the selected amortization period.

Survivor curves were used to reflect the expected dispersion of retirements, thus providing a consistent method of estimating service lives and depreciation for mass property. Iowa type curves were used to depict the estimated survivor curves. For life span groups, the estimate of life characteristics is consistent because the calculated lives of the units within a group are obtained by employing a single probable retirement date for the entire group.

Service Life Estimates

The method of estimating service life consisted of compiling the service life history of the plant accounts, subaccounts or depreciable groups, reducing this history to trends through the use of acceptable actuarial techniques, and forecasting the trend of survivors for each depreciable group on the basis of interpretations of past trends and consideration of Company plans for the future. The combination of the historical trend and the estimated future trend yielded a complete pattern of life characteristics from which the average service life was derived.

The Company's service life estimates used in the depreciation calculation incorporated historical data compiled through 2017 from the property records of the Company. Such data included plant additions, retirements, transfers and other activity. Generally, retirement data for the years 1960 through 2017 were used in the actuarial life table computations which were the primary statistical support of the service life estimates.

A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirement was obtained through field trips conducted during the course of the service life study. Discussions with operating and management personnel also provided information regarding plans for the future which was incorporated in the interpretation and extrapolation of the statistical analyses.

AMORTIZATION OF NET SALVAGE

Inasmuch as this report relates primarily to Pennsylvania rate regulation practices, under which experienced costs of negative net salvage are amortized after their occurrence, no adjustments for expected salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts. The annual provision for recovering negative net salvage is based on the amortization of experienced and estimated net salvage recorded October 1, 2017 through September 30, 2022 over a five-year period.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements (or the portion of the frequency curve with the highest level of retirements) in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family. A higher number designates a higher mode curve.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

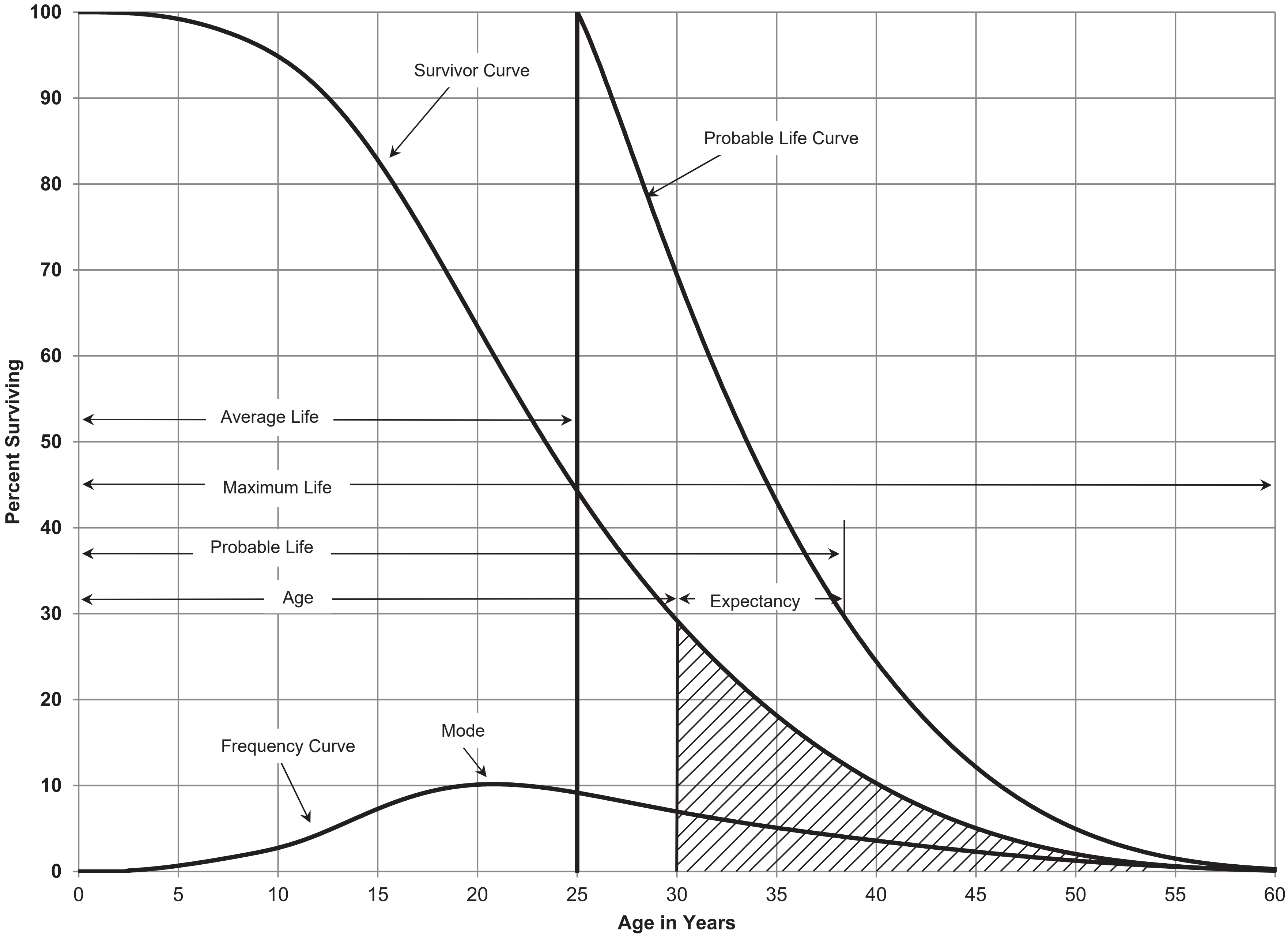

FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

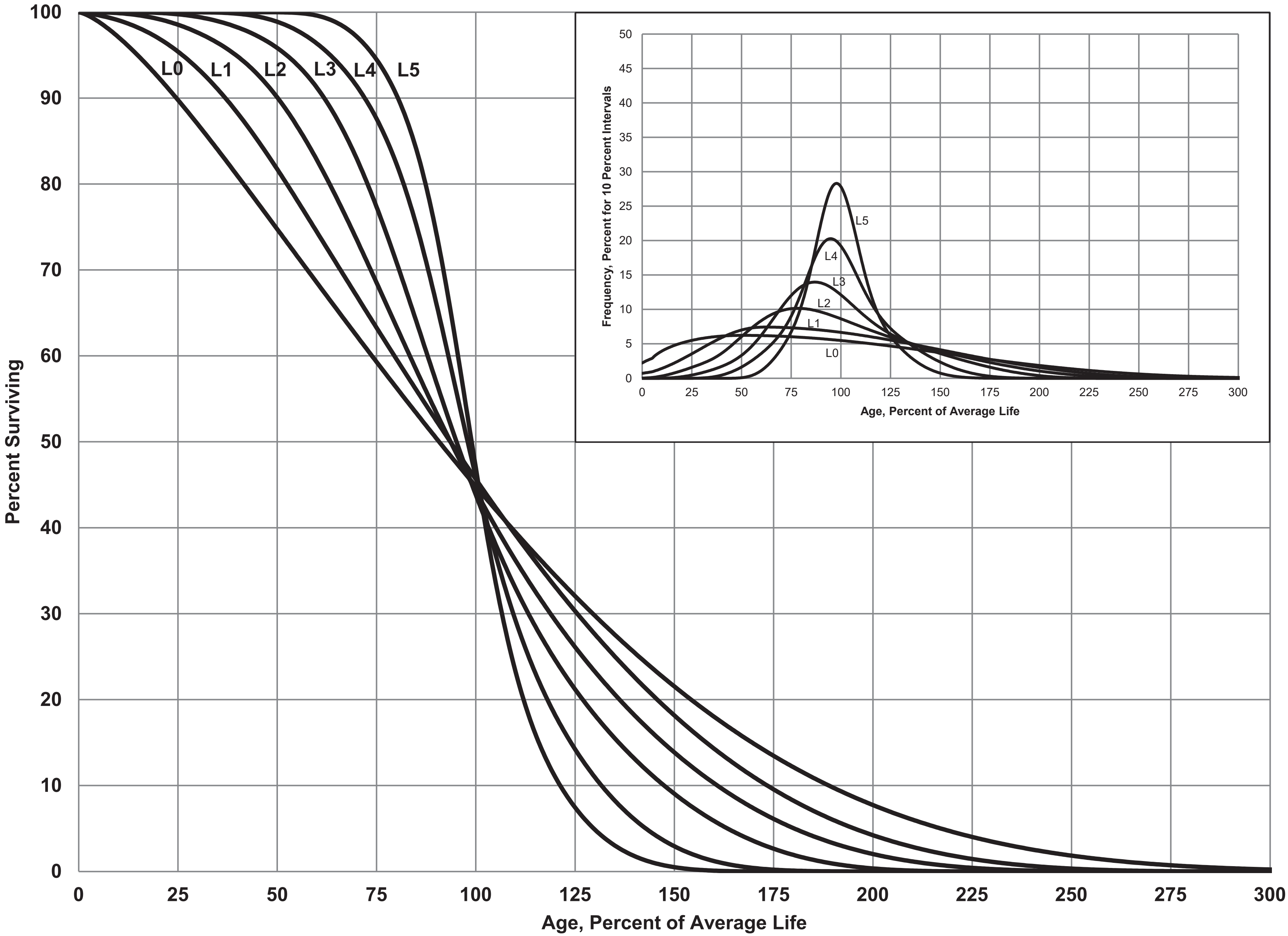

FIGURE 2. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

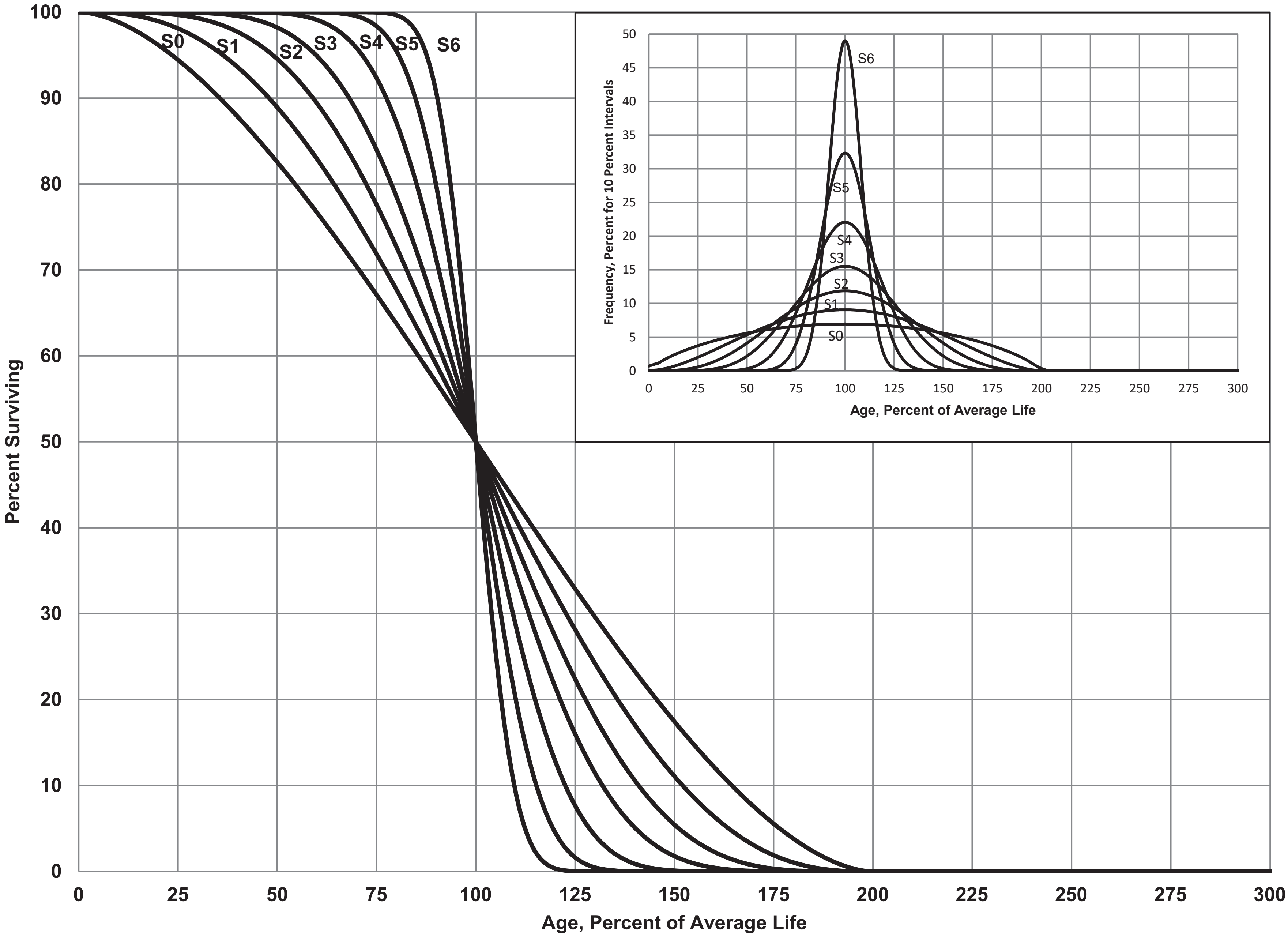

FIGURE 3. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

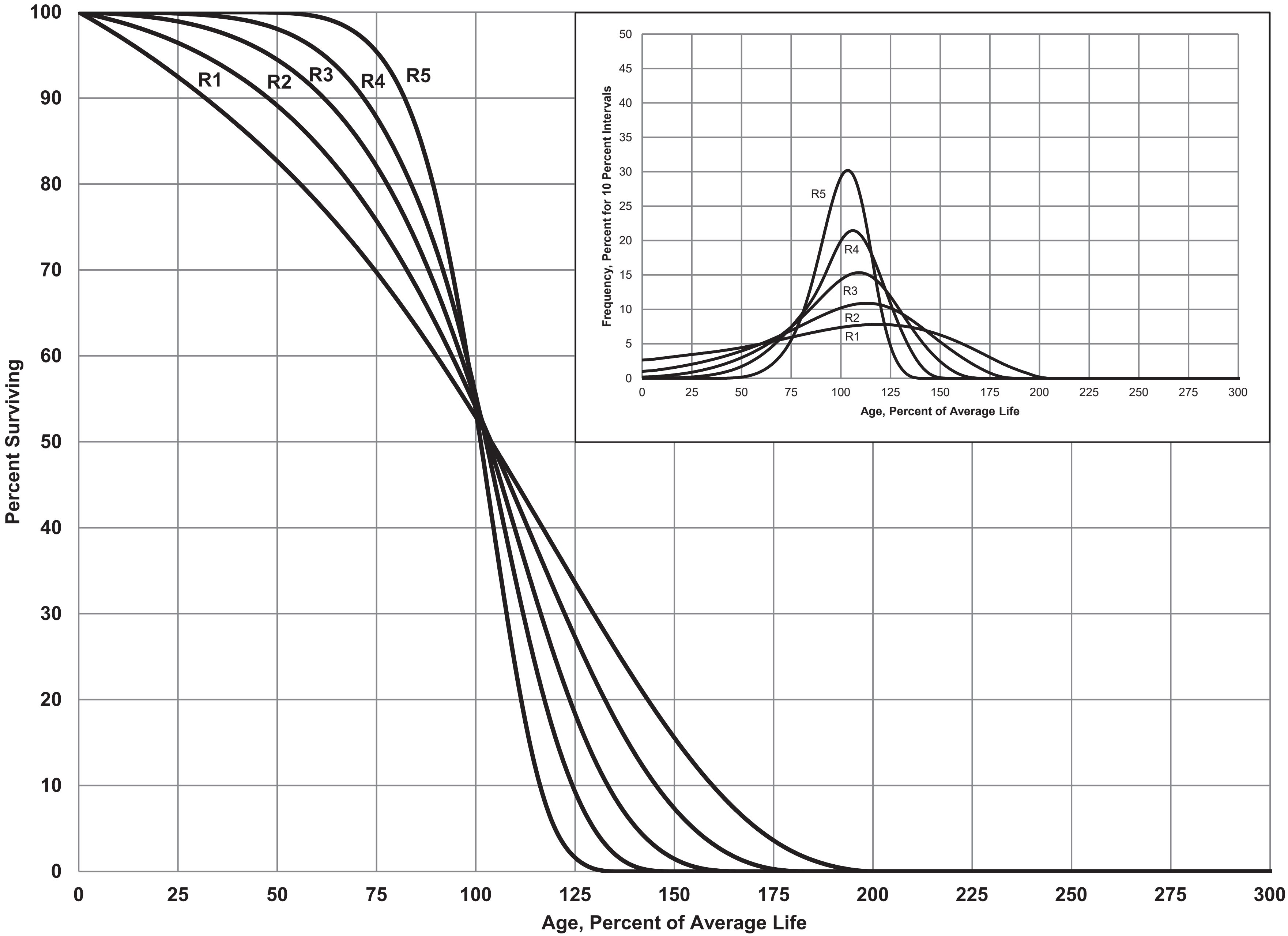

FIGURE 4. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

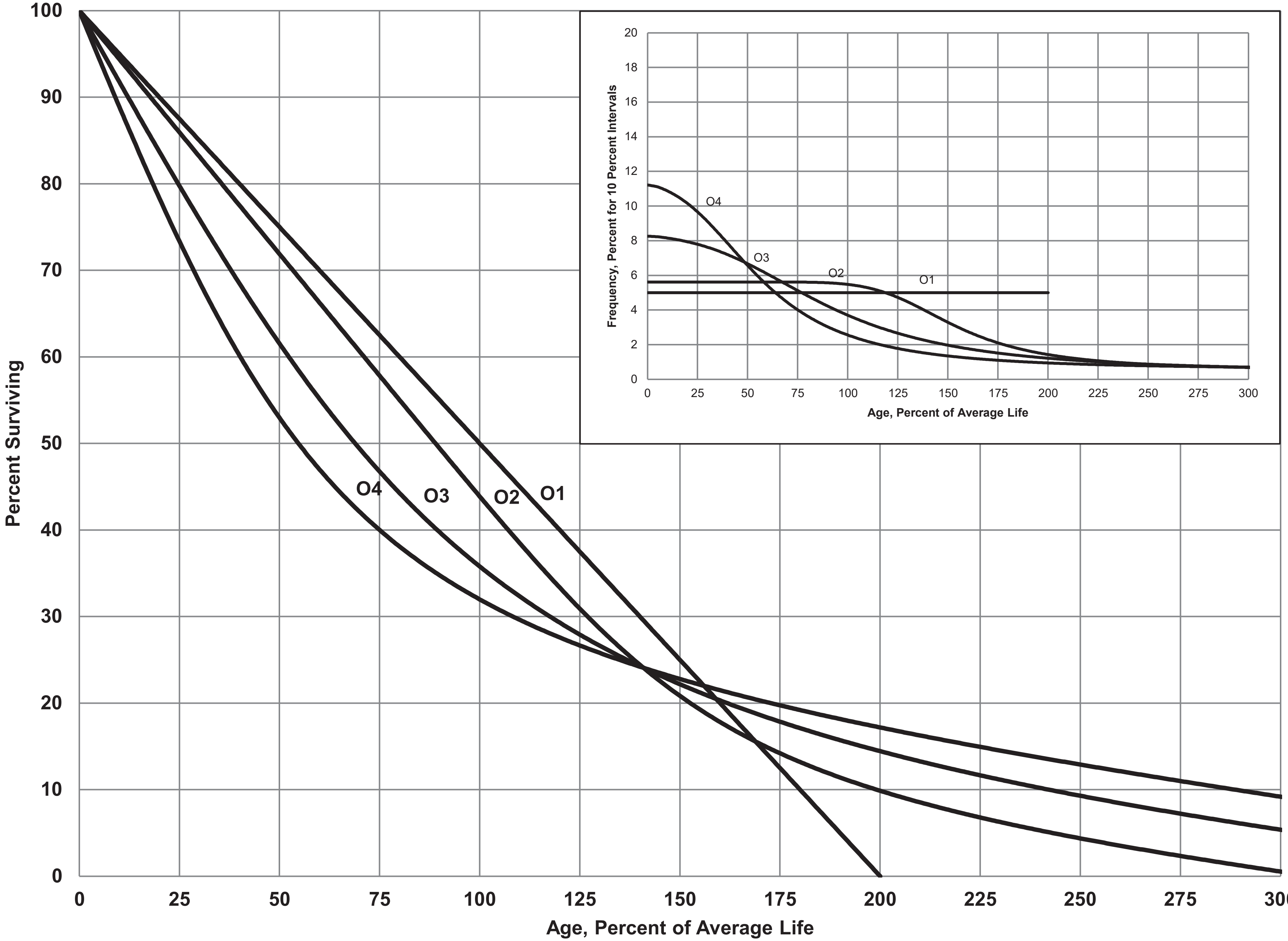

FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text and is also explained in several publications including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band. The band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

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[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2013-2022 for which there were placements during the years 2008-2022. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2008 were retired in 2013. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2013 retirements of 2008 installations and ending with the 2022 retirements of the 2017 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Gannett Fleming

Experience Band 2013-2022 Placement Band 2008-2022

Year Placed	Retirements, Thousands of Dollars During Year 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total During Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2009	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2010	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2011	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2012	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2013	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2014		5	11	12	13	14	15	16	18	20	113	7½-8½
2015			6	12	13	15	16	17	19	19	124	6½-7½
2016				6	13	15	16	17	19	19	131	5½-6½
2017					7	14	16	17	19	20	143	4½-5½
2018						8	18	20	22	23	146	3½-4½
2019							9	20	22	25	150	2½-3½
2020								11	23	25	151	1½-2½
2021									11	24	153	½-1½
2022										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 Placement Band 2008-2022

	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
Year Placed (1)	2013 (2)	2014 (3)	2015 (4)	2016 (5)	2017 (6)	2018 (7)	2019 (8)	2020 (9)	2021 (10)	2022 (11)	Total During Age Interval (12)	Age Interval (13)
2008	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2009	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2010	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2011	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2012	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2013	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2014		-	-	-	-	-	-	-	-	-	6	7½-8½
2015			-	-	-	-	-	-	-	-	-	6½-7½
2016				-	-	-	-	(12)[b]	-	-	-	5½-6½
2017					-	-	-	-	22[a]	-	-	4½-5½
2018						-	-	(19)[b]	-	-	10	3½-4½
2019							-	-	-	-	-	2½-3½
2020								-	-	(102)[c]	(121)	1½-2½
2021									-	-	-	½-1½
2022											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year

[b] Transfer Affecting Exposures at End of Year

[c] Sale with Continued Use

Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2013 through 2022 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2018 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2013-2022
SUMMARIZED BY AGE INTERVAL

Experience Band 2013-2022 | Placement Band 2008-2022

Year Placed	Exposures, Thousands of Dollars – Annual Survivors at the Beginning of the Year: 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total at Beginning of Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2008	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2009	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2010	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2011	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2012	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2013	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2014		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2015			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2016				580[a]	574	561	546	530	501	482	3,057	5½-6½
2017					660[a]	653	639	623	628	609	3,789	4½-5½
2018						750[a]	742	724	685	663	4,332	3½-4½
2019							850[a]	841	821	799	4,955	2½-3½
2020								960[a]	949	926	5,719	1½-2½
2021									1,080[a]	1,069	6,579	½-1½
2022										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2013-2022, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2013-2022 Placement Band 2008-2022

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

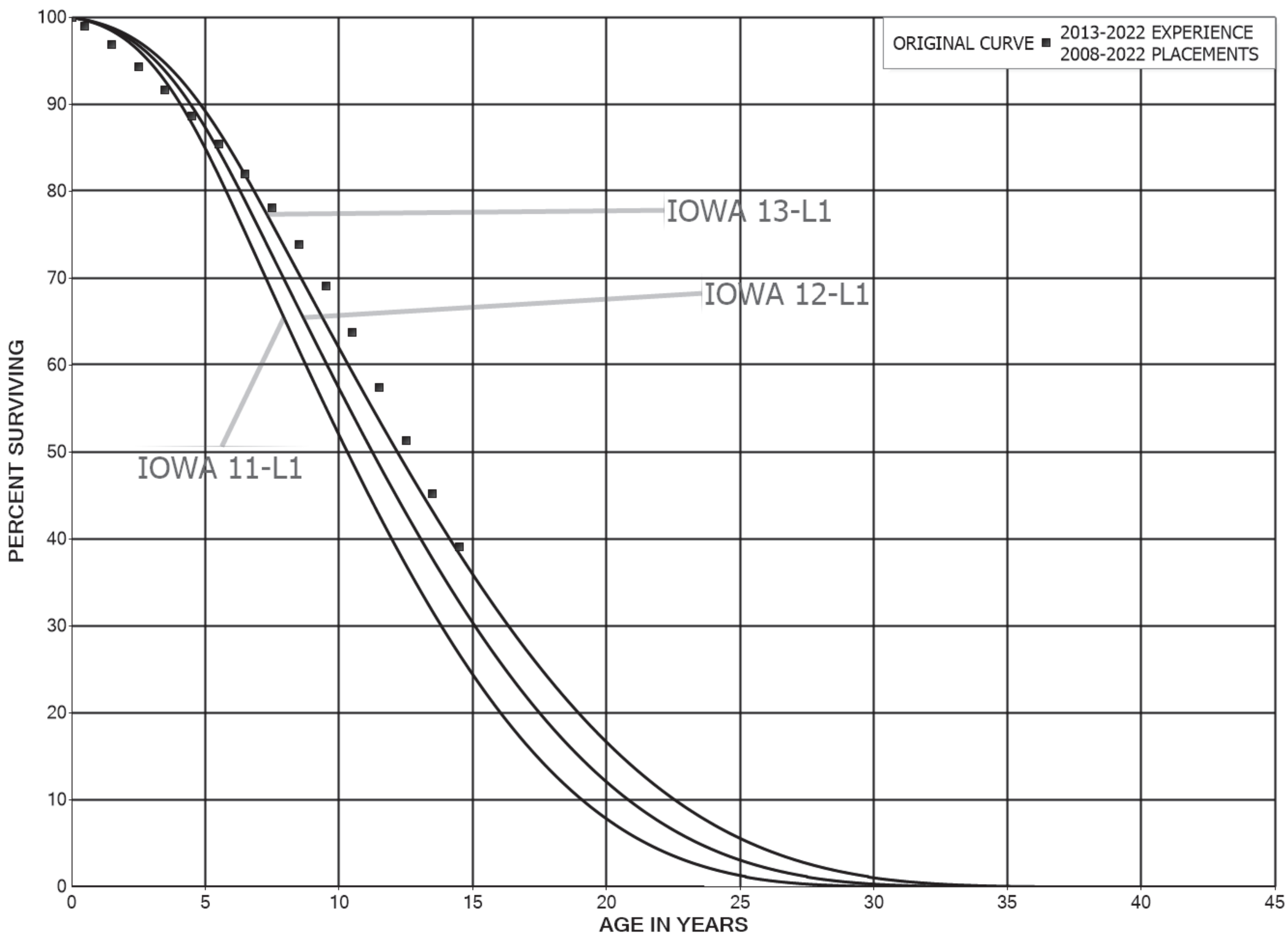


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

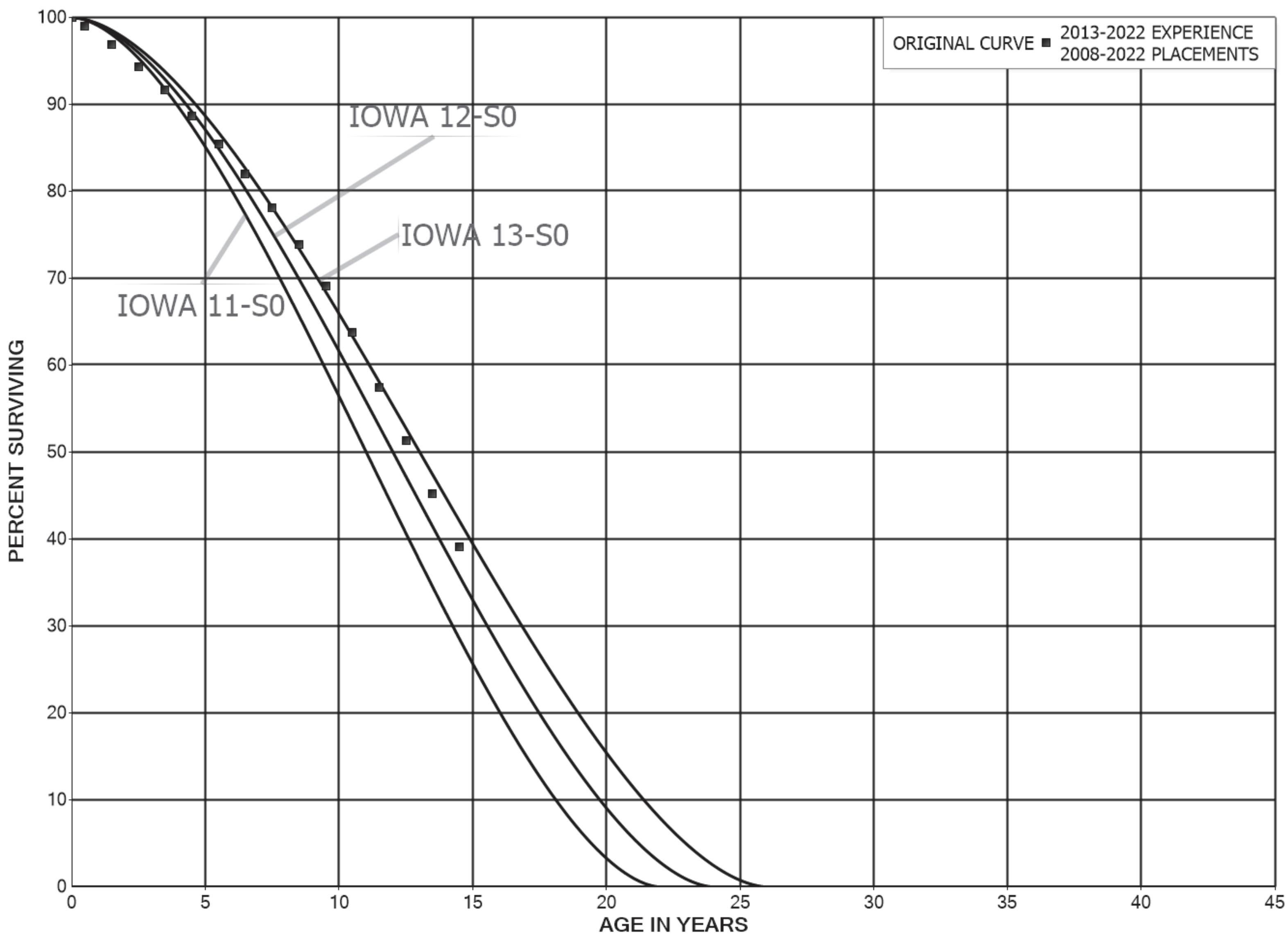


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

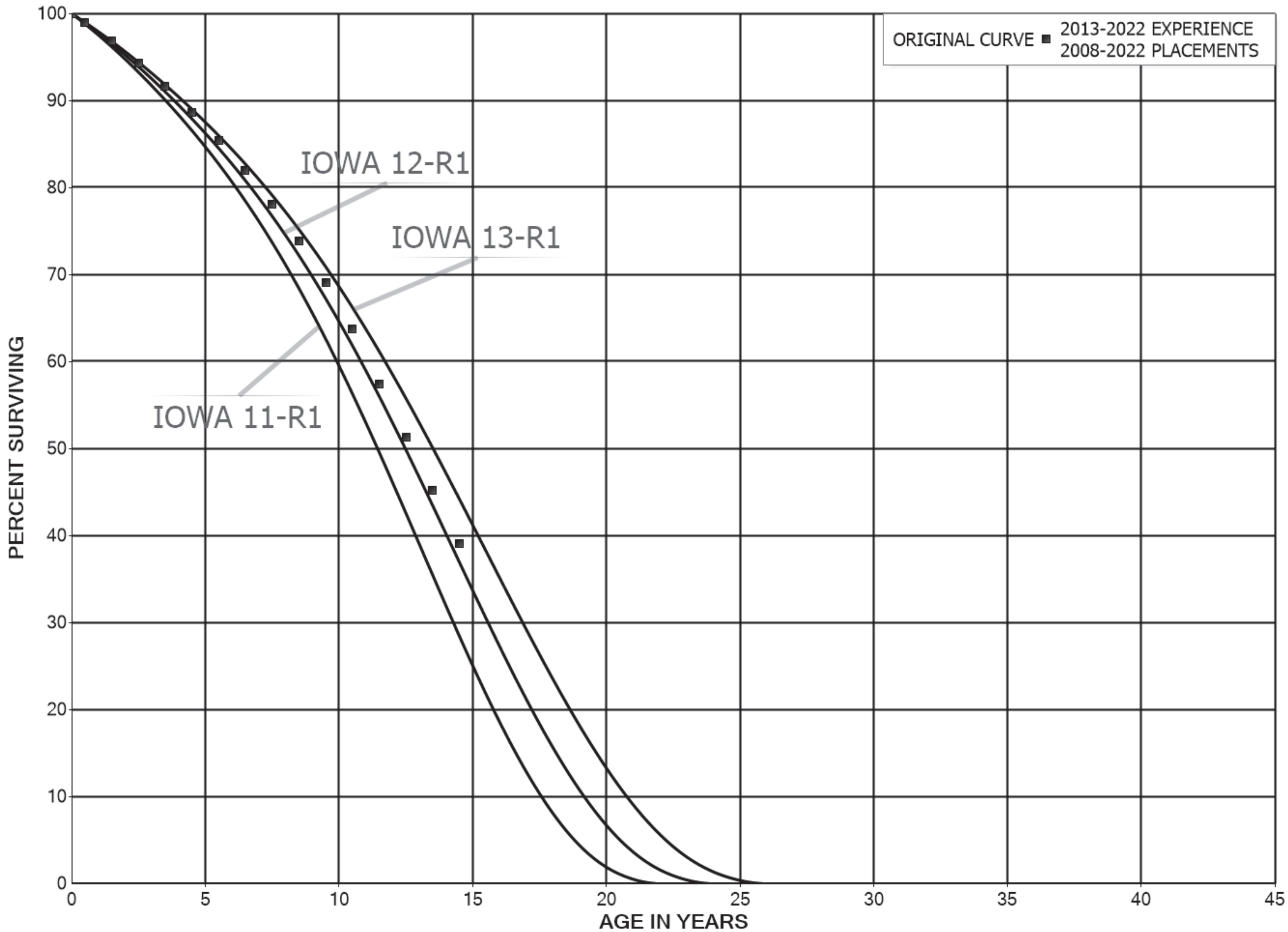
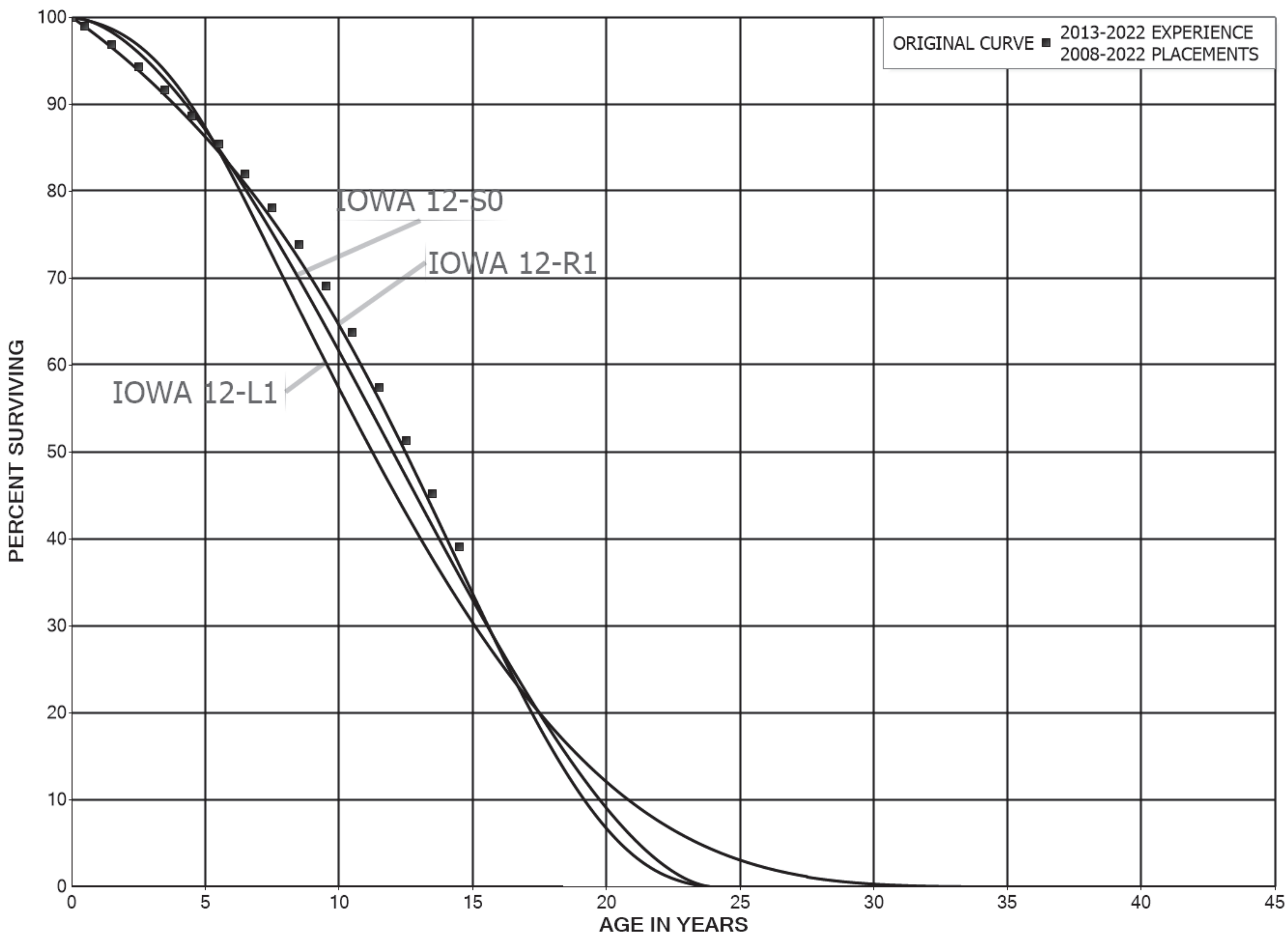


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

Field Trips.

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips have been conducted periodically. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during these field trips. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

During the extensive period of years our firm has been conducting depreciation studies for the Company, the field trips have resulted in numerous reviews of the Company's operating areas. The following is a list of the locations visited during the most recent trips:

August 16, 2018

- Lancaster Service Center
- Main Replacement Project on Conestoga St., Lancaster, PA
- Main Replacement Project on W. Frederick St., Lancaster, PA
- Fruitville City Gate Station
- Lititz Metering Station
- Lebanon Service Center
- Lebanon District Regulating Station
- Ono City Gate Station
- Bern Church Meter Station
- Leesport City Gate Station
- Temple City Gate Station
- Reading (Morgantown Road) Service Center

August 15, 2018

- Stroudsburg Operations Center
- Stroudsburg Measuring Station
- Delaware Water Gap M&R Station
- Bangor City Gate Station
- Mount Bethel Metering Station
- Main Replacement Project on Main Street, Easton, PA

August 15, 2018, cont.

Hellertown City Gate Station
Bethlehem (a.k.a., Lehigh Valley) Service Center

January 25, 2017

Lancaster Service Center
Lancaster District Regulating Station
West Lancaster City Gate Station
Marietta City Gate Station
Middletown (a.k.a., Stoneridge) Service Center
Main replacement, N 17th St & North St, Harrisburg, PA
Grantville City Gate Station
Lebanon City Gate Station

February 3, 2017

Reading Service Center
Reading Plant and Training Center, 4th St & Canal St.
Gas Control Center – Temple
Temple City Gate Station
Bethlehem (a.k.a., Lehigh Valley) Service Center
Route 512 Regulating Station (Temporary), S of Bath, PA
Locust Road Regulating Station
Hellertown City Gate Station
Bethlehem District Regulating Station at Bethlehem Plant

January 29, 2016

Empire Yard – Office and Service Center
Empire Yard District Regulating Station
Wyoming Avenue City Gate Station
Saylor Avenue City Gate Station
Archibald Service Center
Honesdale Service Center
Honesdale City Gate Station
Honesdale District Regulating Station
Watts Hill District Regulating Station

January 23, 2014

Mansfield/Wellsboro Operations Center
Port Allegheny Operations Center
Reed Run Take Station

December 20, 2011

Middletown (a.k.a., Stoneridge) Service Center
Marietta City Gate Station
Columbia City Gate Station
West Lancaster City Gate Station

December 14, 2011, cont.

Manheim District Regulating Station
Fruitville City Gate Station
Lancaster Service Center

December 14, 2011

Hazleton Service Center
West Hazleton District Regulating Station
Harleigh City Gate Station
Humboldt District Regulating Station

December 13, 2011

Lehigh Valley Service Center
4th and Emery District Regulating Station
Hellertown City Gate Station
Bethlehem District Regulating Station
Rosedale City Gate Station
Boyertown City Gate Station
Coventry City Gate Station
Morgantown Service Center
Central Gas Control (CGC)

December 7, 2010

Lewistown Operations Center
Lewistown City Gate Station
Belleville City Gate Station
Huntingdon Service Center
Huntington City Gate Station
Shippensburg Operations Center
Shippensburg City Gate Station

December 6, 2010

Stroudsburg Operations Center
Main Replacement Project, Smith St., East Stroudsburg
Smith St. District Regulator Station
Bangor City Gate Station
Wind Gap City Gate Station
East Stroudsburg City Gate Station
Delaware Water Gap City Gate Station
Palmerton City Gate Station
Palmerton District Regulating Station
Lehighton Operations Center
Frackville Operations Center
Mt. Laurel District Regulator Station
16th and Battery Street Regulator Station

June 7, 2007

Lehigh Valley Service Center
Rich Hill City Gate Regulator Station
Hellertown City Gate Regulator Station
Bally City Gate Station
Temple City Gate Station
Reading Service Center
Morgantown City Gate Station

May 15, 2007

Locust Point City Gate Station
Dauphin City Gate Regulator Station
Hershey City Gate Regulator Station
West Lancaster City Gate Station
Harrisburg Service Center and Warehouse
Lancaster Service Center
Morgantown City Gate Station

June 6, 2002

Lehigh Valley Service Center
Rich Hill City Gate Regulator Station
Hellertown City Gate Regulator Station
Bally City Gate Station
Temple City Gate Station
Reading Service Center
Morgantown City Gate Station

May 13, 2002

Hershey City Gate Station
Lebanon City Gate Station
Lebanon Service Center
Lebanon District Regulating Station
Manheim District Regulating Station
West Lancaster City Gate Station
Lancaster Service Center

May 7, 2002

Harrisburg Service Center
CNG Refueling Station at Arnold Fuel Oil
October 10, 1996
Harrisburg Service Building
Steelton LPG Plant
Marietta City Gate Station
Columbia City Gate Regulator Station
Lancaster Service Center
Lebanon Service Center

October 9, 1996

Reading Service Center
Reading LPG Plant
Temple LNG Plant and Central Gas Control

October 8, 1996

Lehigh Valley Service Center
Allentown Garage and Shop
Rich Hill City Gate Regulator Station
Hellertown City Gate Regulator Station
Bethlehem LPG Plant
Didier Plant

Judgment

The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during the field trips and other conversations with management; and the survivor curve estimates from previous studies of this company and other gas companies.

The current consolidated gas company service life study is based on data through 2017. For a majority of the mass plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses resulted in good to excellent indications of the survivor patterns experienced. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the following accounts:

375 Structures and Improvements
376 Mains - Primarily Steel
376 Mains - Cast Iron
378 Measuring and Regulating Station Equipment -General
379 Measuring and Regulating Station Equipment -City Gate
380 Services
381 Meters
385 Industrial Measuring and Regulating Station Equipment
387 Other Equipment
390 Structures and Improvements
396 Power Operated Equipment

Account 380, Services, is one of the largest depreciable groups and is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged retirement and other plant accounting data were compiled for the years 1951 through 2017. These data were coded in the course of the Company's normal recordkeeping according to plant account or property group, type of transaction, year in which the transaction took place, and year in which the gas plant was placed in service. The data were analyzed by the retirement rate method of life analysis. The survivor curve chart for the account is presented on page VI-69 and the life table for the experience band plotted on the chart immediately follows it.

The survivor curve estimate for this account for the consolidated gas company is the Iowa 46-S1. The survivor curve estimates for the three legacy companies were: 1) UGI Gas: 46-S0.5; 2) PNG: 47-R3 for plastic services and 48-R1 for steel and other services; 3) CPG: 40--R1.5. The service line typically consists of a length of steel or plastic pipe. Steel was predominantly used until the mid-1960's, after which copper and plastic inserts became more predominant. Direct buried plastic pipe began to displace steel and the inserts in the 1980's. Currently, the investment in plastic services represents over 90 percent of the total account balance.

During the 1970's, the rates of service line retirements increased causing the service life to significantly decrease. More recent retirement history indicates a decrease in the retirement levels expressed as a percent of the beginning plant balance. Discussions with operating and management personnel disclosed several reasons for the historical changes. Prior to 1970, the retirement of inactive services often was delayed due to operating practices in effect at that time. The effect of urban renewal in the

Company's service area during the 1970's caused substantially greater retirements at earlier ages, but this cause of retirement has not been as important in the more recent past. Services are often replaced in connection with a main replacement project since it is economic to do so even if the services are in reasonably good condition and not at the end of their physical life. The company during the past five years has significantly increased the miles of cast iron and bare steel main that are replaced annually. Based on the company's most recent plan as set forth in the Long-Term Infrastructure Improvement Plan (LTIIP), the accelerated replacement of cast iron mains will occur over a 15-year period ending in 2027. The accelerated replacement of bare steel mains will occur over a 30-year period ending in 2041. For steel services, the principal cause of retirement continues to be deterioration and the impact of the cast iron and bare steel main replacement program as steel service will be replaced in connection with the cast iron and bare steel main replacement. Steel services also will be retired when the company moves meters located indoors to outside the customer's home. The company plans to move all indoor meters, not located in a historic district, to the outside within the next 15 years. This program will also cause increased meter and meter set retirements in other related accounts such as Accounts 381-384.

The 46-S1 survivor curve estimated for Account 380, Services, also is estimated for Accounts 382, Meter Installations; 383, House Regulators; 384, House Regulator Installations; and 386, Other Property on Customers' Premises. The use of the estimate developed for Account 380, Services, for other property on customers' premises is based on the similar nature of the facilities in these groups. The use of the services estimate for the remaining accounts is based on management's intent to retire these facilities concurrently with the future retirements of service lines.

The third largest depreciable group is Account 376.1, Mains - Primarily Steel. The survivor curve estimate for this account is the Iowa 73-R2.5. In recent years, the rates of retirements of mains have been redistributed, with lesser retirement ratios during earlier age intervals and greater ratios during older age intervals after age 35. This has resulted in a somewhat different indication of the survivor curve during the recent past and for the future. Discussions with operating and management personnel indicated that corrosion control programs, including the use of plastic for smaller size mains, is the most probable cause of fewer early retirements. In addition, highway and urban renewal projects have caused relatively few retirements in the Company's service area in recent years. Increased rates of retirement at older ages are anticipated in conjunction with leak detection programs and street improvements. That is, older mains with a history of leaks will be replaced as municipalities perform street improvements in order to avoid the high cost of repair or replacement when repaving is required. In addition, the company typically will replace service lines in connection with the main replacement. As previously mentioned, the company has in the past five years or so significantly accelerated the rate at which bare steel mains are being replaced. Bare steel and cast iron mains were primarily installed up through 1960. The company has plans to replace all bare steel mains by 2041.

Typical service lives for mains of used by other gas companies range from 55 to 80 years. The Iowa 73-R2.5 survivor curve is within the range and is a reasonable interpretation of the significant portion of the stub survivor curve through age 65 and reflects the outlook of management.

The interim survivor curve estimate for Account 376.2, Mains – Cast Iron is the Iowa 65-R1. The 65-R1 survivor curve was based on the results of the life analysis for the experience band 1960-2017. The 65-year average service life estimate is consistent with management's expectations and estimates used by other gas companies. An estimated probable retirement date, or truncation date, was used for this account as well. The estimated probable retirement date (i.e., September 30, 2027) coincides with the date the company plans to complete its replacement of cast iron mains.

Similar studies were performed for the remaining significant mass plant accounts. The results of the statistical analyses are presented in account sequence in this report, beginning on page VI-2. The major structures included in Account 390.1, Structures and Improvements, were separated from the smaller structures for purposes of the study. The major structures group consists of twelve structures or office complexes of significant size and of a nature that the life span procedure is appropriate. The life spans assigned to the major structures were typically 45 to 75 years from the date of major installation and varied within this range based on individual circumstances such as size, condition, type of construction, location, and management's plans. Continued use is planned for most of the major structures, although the Lebanon and Lancaster service centers may be consolidated into neighboring service centers in the near term.

The Iowa 80-R1.5 interim survivor curve was judged appropriate for the major structures based on the 1942-2017 interim retirement experience, our observations of the buildings, consideration of the facilities which will be retired during the estimated life spans, and a review of the interim survivor curves derived for similar structures of other gas companies.

Generally, the survivor curve estimates for the remainder of the accounts, which comprise a minor portion of the total depreciable original cost, were based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data, and a general knowledge of the service lives for similar equipment in other gas companies.

PART IV. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART IV. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Group Depreciation Procedures

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally, the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group.

In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. This procedure eliminates the need to base depreciation on average lives, inasmuch as each group is equivalent to a unit having a single life. The full costs of short-lived units are accrued during their lives, leaving no deferral of accruals required to be added to the annual costs associated with long-lived units. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

Remaining Life Annual Accruals

For the purpose of calculating remaining life accrual rates as of September 30, 2022, the estimated book depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation for the vintages calculated by the average service life procedure and for the vintages calculated by the equal life group procedure follow. The detailed calculations are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future whole life depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account, based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life\ Expectancy}{Average\ Service\ Life}.$$

Equal Life Group Procedure

In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life is derived by compositing the individual equal life group remaining lives in accordance with the following equation:

$$\textit{Composite Remaining Life} \ - \ \frac{(\frac{\textit{Book Cost}}{\textit{Life}} \, x \ \textit{Remaining Life})}{\frac{\textit{Book Cost}}{\textit{Life}}}$$

The book costs and lives of the several equal life groups which are summed in the foregoing equation are defined by the estimated future survivor curve.

Inasmuch as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

$$\textit{Composite Remaining LIfe} \ = \ \frac{\sum \textit{Whole Life Future Accruals}}{\sum \textit{Whole Life Annual Accruals}}$$

or

$$\textit{Composite Remaining Life} \ = \ \frac{\sum \textit{Book Cost} \ - \ \textit{Calc. Reserve}}{\sum \textit{Whole Life Annual Accrual}}.$$

The annual accrual rate for each account is equal to the sum of the remaining life annual accruals for all vintages divided by the account's total original cost. The account's "composite remaining life" is calculated by dividing the sum of the future book accruals for all vintages by the sum of the remaining life annual accruals for all vintages.

The calculated accrued depreciation in the equal life group procedure also represents that portion of depreciable cost which will not be allocated to expense through future accruals. However, the calculation is based at the equal life group level rather than the vintage group level and does not require the use of averages. The equal life group accrued depreciation ratio is calculated as follows:

$$Ratio = \frac{Remaining\ Life}{Average\ Service\ Life}.$$

Inasmuch as service life minus remaining life equals age, when averages are not employed, the foregoing equation reduces to:

$$Ratio = \frac{Age}{Service\ Life}.$$

The table on the following page illustrates the procedure for calculating straight line equal life group accrued depreciation, using an Iowa 10-L2.5 survivor curve and a September 30, 2022 calculation date.

In the table, each equal life group is defined by the age interval shown in columns 1 and 2, which identify the ages at which the first and last retirement of each group occur. The group's designated life, shown in column 3, is the midpoint of the interval. In the calculation, the equal life groups of each vintage are arranged such that the midpoint of each one-year age interval coincides with the calculation date, e.g., September 30, in this case. This enables the calculation of annual accruals which are centered on, or as of, the same date as the calculation of accrued depreciation.

The retirement during each age interval, shown in column 4, is the size of each equal life group. It is derived from the Iowa 10-L2.5 survivor curve and is the difference between the percents surviving (not shown) at the beginning and end of the age interval.

DETAILED COMPUTATION OF ANNUAL AND ACCRUED FACTORS USING THE EQUAL LIFE GROUP PROCEDURE

INPUT PARAMETERS:
CALCULATION DATE.. 9-30-2022
SURVIVOR CURVE.... 10-L2.5

AGE INTERVAL BEG (1)	END (2)	LIFE (3)	RETIREMENTS DURING INTERVAL (4)	GROUP ANNUAL ACCRUAL (5)=(4)/(3)	YEAR INST (6)	SUMMATION OF ANNUAL ACCRUALS (7)	AVERAGE PERCENT SURVIVING (8)	ANNUAL FACTOR (9)	ACCRUED FACTOR (10)
0.000	1.000	0.500	0.05547	0.05547000000	2022	11.97110572523	99.985092	0.1197	0.0599
1.000	2.000	1.500	0.37986	0.25324000000	2021	11.78901572523	99.754600	0.1182	0.1773
2.000	3.000	2.500	1.03309	0.41323600000	2020	11.45577772523	99.048125	0.1157	0.2893
3.000	4.000	3.500	1.98796	0.56798857143	2019	10.96516543951	97.537600	0.1124	0.3934
4.000	5.000	4.500	3.59099	0.79799777778	2018	10.28217226491	94.748125	0.1085	0.4883
5.000	6.000	5.500	5.95921	1.08349272727	2017	9.34142701238	89.973025	0.1038	0.5709
6.000	7.000	6.500	8.74568	1.34548923077	2016	8.12693603336	82.620580	0.0984	0.6396
7.000	8.000	7.500	11.07393	1.47652400000	2015	6.71592941798	72.710775	0.0924	0.6930
8.000	9.000	8.500	11.94865	1.40572352941	2014	5.27480565327	61.199485	0.0862	0.7327
9.000	10.000	9.500	11.17963	1.17680315789	2013	3.98354230962	49.635345	0.0803	0.7629
10.000	11.000	10.500	9.46724	0.90164190476	2012	2.94431977830	39.311910	0.0749	0.7865
11.000	12.000	11.500	7.66323	0.66636782609	2011	2.16031491287	30.746675	0.0703	0.8085
12.000	13.000	12.500	6.19891	0.49591280000	2010	1.57917459983	23.815605	0.0663	0.8288
13.000	14.000	13.500	5.08620	0.37675555556	2009	1.14284042205	18.173050	0.0629	0.8492
14.000	15.000	14.500	4.18121	0.28835931034	2008	0.81028298910	13.539345	0.0598	0.8671
15.000	16.000	15.500	3.37519	0.21775419355	2007	0.55722623715	9.761145	0.0571	0.8851
16.000	17.000	16.500	2.63062	0.15943151515	2006	0.36863338280	6.758240	0.0545	0.8993
17.000	18.000	17.500	1.95714	0.11183657143	2005	0.23299933951	4.464360	0.0522	0.9135
18.000	19.000	18.500	1.37770	0.07447027027	2004	0.13984591866	2.796940	0.0500	0.9250
19.000	20.000	19.500	0.91035	0.04668461538	2003	0.07926847584	1.652915	0.0480	0.9360
20.000	21.000	20.500	0.56084	0.02735804878	2002	0.04224714376	0.917320	0.0461	0.9451
21.000	22.000	21.500	0.32136	0.01494697674	2001	0.02109463100	0.476220	0.0443	0.9525
22.000	23.000	22.500	0.17231	0.00765822222	2000	0.00979203152	0.229385	0.0427	0.9608
23.000	24.000	23.500	0.08679	0.00369319149	1999	0.00411632466	0.099835	0.0412	0.9682
24.000	25.000	24.500	0.03893	0.00158897959	1998	0.00147523912	0.036975	0.0399	0.9776
25.000	26.000	25.500	0.01385	0.00054313725	1997	0.00040918070	0.010585	0.0387	0.9869
26.000	27.000	26.500	0.00330	0.00012452830	1996	0.00007534793	0.002010	0.0375	0.9938
27.000	28.000	27.500	0.00035	0.00001272727	1995	0.00000672014	0.000185	0.0363	0.9983
28.000	28.100	28.050	0.00001	0.00000035651	1994	0.00000001783	0.000001	0.0178	1.0000
TOTAL			100.00000						

Each equal life group's whole life annual accrual, shown in column 5, equals the group's size (column 4) divided by its life (column 3), except that for the first age interval, the annual accrual is set equal to the group's size.

Columns 6 through 10 show the derivation of the whole life annual factor and accrued factor for each vintage based on the data developed in the first five columns. The year installed is shown in column 6. For all vintages other than the first and last year (2022 and 1994), the summation of annual accruals for each year installed, shown in column 7, is calculated by adding one-half of the group annual accrual (column 5) for that vintage's current age interval plus the group annual accruals for all succeeding age intervals. For example, the figure 11.78901572523 for 2019 equals one-half of 0.25324000000 plus all of the succeeding figures in column 5. Only one-half of the annual accrual for the vintage's current age interval group is included in the summation because the equal life group for that interval expires at the midpoint of the current year.

The summation of annual accruals (column 7) for installations during 2022 is calculated on the basis of an in-service date at the midpoint of the first nine months, i.e., four and one-half months prior to September 30. Since the overall calculation is centered on September 30, 2022, the accrual for 2022 installations (during the first nine months) represents only 0.875 of one year, 0.375 of a year prior to September 30 plus one-half year following September 30. For this reason, the first figure in column 7, for vintage 2022, equals the group annual accrual for 2022 plus 0.875 of the group annual accruals for each of the subsequent years.

The average percent surviving, derived from the Iowa 10-L2.5 survivor curve, is shown in column 8 for each age interval. The annual factor, shown in column 9, is the result of dividing the summation of annual accruals (column 7) by the average percent surviving (column 8).

The accrued depreciation factor, shown in column 10, equals the annual factor multiplied by the age of the group at September 30, 2022.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization, as defined in the Uniform System of Accounts, is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is appropriate for certain General Plant accounts that represent numerous units of property, but a very small portion of depreciable gas plant in service. The accounts and their amortization periods are as follows:

Account		Amortization Period, Years
391,	Office Furniture and Equipment	
	Furniture	20
	Equipment	10
	Computer Equipment	5
	Software	10
393,	Stores Equipment	20
394,	Tools, Shop and Garage Equipment	20
395,	Laboratory Equipment	20
397,	Communication Equipment	10
398,	Miscellaneous Equipment	15

For the purpose of calculating annual amortization amounts at September 30, 2022, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

AMORTIZATION OF NET SALVAGE

Experienced salvage is incorporated in the results of the study, as it was reported on the Company's books and records for the period October 1, 2017 through September 30, 2021, and as estimated for the twelve months ended September 30, 2022. The five-year amortization calculations are shown in Table 4.

Net salvage experienced during the five-year period is presented in this manner to determine the amount of negative net salvage to be amortized for book purposes. In developing the amount to be amortized, the data for the accounts which experienced positive net salvage have been netted with those for accounts which experienced negative net salvage.

In order to be consistent with this manner of recognizing salvage, no adjustments for salvage were made to the annual accruals and accrued depreciation calculated for each individual account. Also, there were no exclusions from the 2018 through 2022 experienced and estimated net salvage amounts that were used to determine the five-year net salvage amortization amount for each account.

PART V. RESULTS OF STUDY

PART V. RESULTS OF STUDY

DESCRIPTION OF SUMMARY TABULATIONS

Tables 1 through 4 presented on pages V-4 through V-13 summarize the results of the depreciation study at September 30, 2022 for the consolidated UGI gas company. Table 1 sets forth, by depreciable group, the estimated survivor curve, original cost, book depreciation reserve at September 30, 2022, future book accruals, and calculated annual accrual amount and rate. Table 2 presents the bringforward of the book reserve to September 30, 2022. Table 3 sets forth the calculation of the depreciation accruals for the twelve months ended September 30, 2022. Table 4 presents the annual amortization of experienced and estimated net salvage based on the period 2018 through 2022.

DESCRIPTION OF DETAILED TABULATIONS

Supporting statistical data for the estimates of average service lives and survivor curves, the annual depreciation calculations, and salvage and cost of removal for the years 2018-2022 are presented in three sections.

The section beginning on page VI-1 sets forth, for each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. A cumulative summary, by year installed, for gas plant and the supporting data for the original cost depreciation calculations are presented in the section beginning on page VII-1. The tabulations of experienced and estimated net salvage by year by account for the five-year period, 2018-2022, are presented in the section beginning on page VIII-1.

In Part VI, the survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the type curve designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. In cases where only a segment of the estimated curve is used in the depreciation calculation, the numeral used for identification purposes is not a designation of the average life of the group. The titles of the charts indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which were plotted. The experience band indicates the range of years for which the retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation related to original cost are presented in Part VII and indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, allocated book reserve, future book accruals, remaining life expectancy and the calculated annual accrual.

Detailed tabulations setting forth the cost of removal and salvage amounts, by plant account for each year, are presented beginning on page VIII-2. The total salvage and removal costs, by year, were used to calculate the five-year net salvage amortization presented in Table 4 in Part V.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2022

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
GAS PLANT								
PRODUCTION PLANT								
305	MANUFACTURED GAS PLANT SITE REMEDIATION		FULLY ACCRUED *	0	92,158	(92,158)	-	0
325.2	PRODUCING LEASEHOLDS		55 - S0.5	163,100	162,102	998	0.02	34
325.4	RIGHTS-OF-WAY		60 - R1	30,277	29,699	578	0.06	17
328	FIELD MEASURING AND REGULATING STATION STRUCTURES		FULLY ACCRUED	1,263	1,263	0	-	0
329	OTHER STRUCTURES		FULLY ACCRUED	44,785	44,783	2	-	0
330	PRODUCING GAS WELLS - WELL CONSTRUCTION		FULLY ACCRUED	18,209	18,209	0	-	0
331	PRODUCING GAS WELLS - WELL EQUIPMENT		FULLY ACCRUED	24,441	24,441	0	-	0
332	FIELD LINES		47 - L0	750,689	725,816	24,873	0.13	977
334	FIELD MEASURING AND REGULATING STATION EQUIPMENT		24 - O3	89,725	84,969	4,756	0.45	406
335	DRILLING AND CLEANING EQUIPMENT		30 - S0.5	49,604	49,483	121	0.04	18
337	OTHER EQUIPMENT		FULLY ACCRUED	11,062	11,062	0	-	0
TOTAL PRODUCTION PLANT				**1,183,155**	**1,243,985**	**(60,830)**	**0.12**	**1,452**
STORAGE PLANT								
352.01	WELL CONSTRUCTION		FULLY ACCRUED *	0	(35,934)	35,934	-	0
TOTAL STORAGE PLANT				**0**	**(35,934)**	**35,934**	-	**0**
TRANSMISSION PLANT								
365.2	RIGHTS-OF-WAY		70 - R4	868,160	536,830	331,330	1.34	11,659
366	STRUCTURES AND IMPROVEMENTS		30 - R1	162,216	146,334	15,882	0.75	1,214
367	MAINS		70 - R3	39,074,497	21,888,205	17,186,292	1.17	455,718
369	MEASURING AND REGULATING STATION EQUIPMENT		49 - R2	6,152,338	3,965,987	2,186,351	1.50	91,996
370	COMMUNICATION EQUIPMENT		23 - R0.5	3,486,136	2,140,531	1,345,605	2.98	103,824
371	OTHER EQUIPMENT		35 - R2.5	140,637	129,565	11,072	0.82	1,147
371.1	TESTING EQUIPMENT		20 - R3	210,011	152,562	57,449	2.41	5,053
TOTAL TRANSMISSION PLANT				**50,093,995**	**28,960,014**	**21,133,981**	**1.34**	**670,611**
DISTRIBUTION PLANT								
374.2	RIGHTS-OF-WAY		75 - R3	3,544,569	1,380,979	2,163,590	1.30	46,033
375	STRUCTURES AND IMPROVEMENTS		50 - S0.5	5,554,376	3,255,821	2,298,555	1.57	87,278
376.1	MAINS - PRIMARILY STEEL		73 - R2.5	642,022,976	186,259,998	455,762,978	1.53	9,810,096
376.2	MAINS - CAST IRON	09-2027	65 - R1	1,823,760	17,698	1,806,062	21.43	390,742
376.3	MAINS - PLASTIC		67 - R3	1,502,936,183	290,557,616	1,212,378,567	1.65	24,808,067
376.5	MAINS - PRIMARILY WROUGHT IRON	09-2041	70 - R1	290,185	243,917	46,268	1.64	4,755
376.7	REG AFUDC		5 - SQ	1,322,088	398,720	923,368	19.95	263,819
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		47 - S0	157,824,796	26,618,827	131,205,969	2.99	4,717,141
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		45 - R2	25,635,909	8,409,477	17,226,432	2.42	621,339
380	SERVICES		46 - S1	1,386,388,924	396,104,279	990,284,645	2.50	34,633,612
381	METERS		35 - R2	152,689,621	55,211,410	97,478,211	3.15	4,804,514
381.1	METERS - ERTS		17 - S3	23,249,326	19,365,192	3,884,134	2.61	606,443
382	METER INSTALLATIONS		46 - S1	103,616,708	36,058,830	67,557,878	2.39	2,477,628
383	HOUSE REGULATORS		46 - S1	10,665,811	6,698,745	3,967,066	1.52	162,009
384	HOUSE REGULATOR INSTALLATIONS		46 - S1	18,727,622	8,896,752	9,830,870	2.03	381,023
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		45 - R2	39,907,546	17,515,028	22,392,518	2.10	837,666
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES		46 - S1	68,824	(94,200)	163,024	14.09	9,695
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS		45 - R2	953,218	663,828	289,390	1.55	14,794
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS		25 - R3	24,705	24,705	0	-	0
387	OTHER EQUIPMENT		35 - R2.5	4,871,243	2,932,388	1,938,855	2.10	102,328
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE		25 - SQ	1,490,664	1,468,898	21,766	0.28	4,180
TOTAL DISTRIBUTION PLANT				**4,083,609,054**	**1,061,988,908**	**3,021,620,146**	**2.08**	**84,783,162**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2022

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS		VARIOUS**	112,227,654	42,197,098	70,030,557	4.17	3,571,458
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,776,937	1,008,484	3,768,453	6.16	294,113
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		10 - SQ	193,634	48,200	145,434	9.88	19,138
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT		5 - SQ	662,977	490,975	172,002	18.92	125,456
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE			0	(42,186)	42,186	-	0
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S		8 - L2.5	3,614,867	931,201	2,683,666	14.20	513,491
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS		10 - L2.5	28,028,980	7,238,621	20,790,359	11.45	3,208,839
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICL		12 - L3	3,304,380	998,425	2,305,955	8.77	289,931
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS		12 - L3	5,097,821	1,502,377	3,595,444	8.65	441,106
392.5	TRANSPORTATION EQUIPMENT - TRAILERS		15 - L2	2,364,560	688,700	1,675,860	7.35	173,809
393	STORES EQUIPMENT		20 - SQ	17,606	6,326	11,280	4.96	874
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	37,478,860	12,823,468	24,655,392	5.24	1,962,039
395	LABORATORY EQUIPMENT		20 - SQ	437,779	112,149	325,630	5.05	22,097
396	POWER OPERATED EQUIPMENT		15 - L2	6,570,611	2,417,013	4,153,598	7.17	470,815
397	COMMUNICATION EQUIPMENT		10 - SQ	938,798	401,771	537,027	11.83	111,023
398	MISCELLANEOUS EQUIPMENT		15 - SQ	2,390,379	889,505	1,500,874	9.08	217,117
TOTAL GENERAL PLANT				**208,105,843**	**71,712,127**	**136,393,717**	**5.49**	**11,421,306**
TOTAL DEPRECIABLE GAS PLANT				**4,342,992,047**	**1,163,869,100**	**3,179,122,948**	**2.23**	**96,876,531**
NONDEPRECIABLE PLANT								
301	ORGANIZATION			166,477				
302	FRANCHISES AND CONSENTS			193,597				
303	MISCELLANEOUS INTANGIBLE PLANT			289,868				
304.1	LAND AND LAND RIGHTS - LAND			375,198				
304.2	LAND AND LAND RIGHTS - LAND RIGHTS			6,454				
325.1	PRODUCING LANDS			13,029				
325.5	OTHER LAND			1,134				
365.1	LAND			47,323				
374.1	LAND AND LAND RIGHTS - LAND			849,347				
374.2	LAND AND LAND RIGHTS - LAND RIGHTS			7,305,823				
389.1	LAND AND LAND RIGHTS - LAND			10,369,471				
389.2	LAND AND LAND RIGHTS - LAND RIGHTS			1,313				
TOTAL NONDEPRECIABLE PLANT				**19,619,034**				
TOTAL GAS PLANT				**4,362,611,081**				

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2022

ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
OTHER UTILITY PLANT							
COMMON PLANT							
301 ORGANIZATION (NONDEPRECIABLE)			138,964				
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108				
390.1 STRUCTURES AND IMPROVEMENTS	01-2069	70 - R1	34,740,353	2,943,559	31,796,794	2.90	1,007,865
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY			0	0	0	-	0
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,367,824	1,014,315	3,353,509	5.34	233,169
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	1,442,208	516,102	926,106	22.21	320,294
392.1 TRANSPORTATION EQUIPMENT - CARS		7 - L2.5	71,637	71,637	0	-	0
398 MISCELLANEOUS EQUIPMENT		10 - SQ	27,967	3,880	24,087	11.48	3,212
TOTAL COMMON PLANT			**47,736,061**	**4,549,493**	**36,100,496**	**3.85**	**1,564,540**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 88.97%			**42,470,773**	**4,047,684**	**32,118,611**		**1,391,971**
INFORMATION SERVICES (IS)							
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	30,143 #	28,532	1,611	3.78	1,139
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	17,576,725 #	12,323,496	5,253,229	19.02	3,342,456
391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE		SQUARE	13,499,682	2,950,328	10,549,354	11.00	1,485,108
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	46,573,593 #	10,614,784	35,958,809	10.32	4,805,208
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	134,333,306 #	42,466,804	91,866,502	6.70	8,998,242
TOTAL INFORMATION SERVICES			**212,013,449**	**68,383,944**	**143,629,505**	**8.79**	**18,632,153**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 91.68%			**194,373,930**	**62,694,400**	**131,679,530**		**17,081,958**
READING SERVICE CENTER							
390.1 STRUCTURES AND IMPROVEMENTS	06-2030	80 - R1.5	2,213,194	1,559,965	653,229	3.89	86,104
LESS READING SERVICE CENTER ALLOCATED TO ELECTRIC DIVISION - 9.31%			**206,048**	**145,233**	**60,816**		**8,016**
EMPIRE YARD BUILDING							
390.1 STRUCTURES AND IMPROVEMENTS			14,122,387	8,165,613	5,956,774	1.85	260,724
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%			**1,845,796**	**1,067,246**	**778,550**		**34,077**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ALL GAS DIVISIONS			**234,792,859**	**65,529,605**	**162,958,775**		**18,431,836**
TOTAL PLANT IN SERVICE			**4,597,403,940**	**1,229,398,705**	**3,342,081,723**		**115,308,367**
AMORTIZATION OF NEGATIVE NET SALVAGE							*6,776,251*
GRAND TOTAL			**4,597,403,940**	**1,229,398,705**	**3,342,081,723**		**122,084,618**

* ACCOUNTS 305 AND 352.01 HAVE NO REMAINING DEPRECIATION ACCRUALS. THE FUTURE ACCRUALS SHOWN ARE RELATED TO THE AMORTIZATION OF NEGATIVE NET SALVAGE.
** SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES.INDIVIDUAL BUILDINGS ARE LIFE SPANNED.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2021 PROJECTED TO SEPTEMBER 30, 2022

	ACCOUNT	BOOK RESERVE AT BEGINNING OF YEAR	ANNUAL ACCRUAL	AMORTIZATION OF NET SALVAGE	RETIREMENTS	GROSS SALVAGE	COST OF REMOVAL	TRANSFERS AND ADJUSTMENTS	BOOK RESERVE AT END OF YEAR	BOOK RESERVE AS A PERCENT OF ORIGINAL COST
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
GAS PLANT										
	PRODUCTION PLANT									
305	MANUFACTURED GAS PLANT SITE REMEDIATION	100,374	0	(8,216)	0	0	0	0	92,158	0.00
325.2	PRODUCING LEASEHOLDS	162,069	33	0	0	0	0	0	162,102	99.39
325.4	RIGHTS-OF-WAY	29,681	18	0	0	0	0	0	29,699	98.09
328	FIELD MEASURING AND REGULATING STATION STRUCTURES	1,263	0	0	0	0	0	0	1,263	100.00
329	OTHER STRUCTURES	44,783	0	0	0	0	0	0	44,783	100.00
330	PRODUCING GAS WELLS - WELL CONSTRUCTION	18,209	0	0	0	0	0	0	18,209	100.00
331	PRODUCING GAS WELLS - WELL EQUIPMENT	24,441	0	0	0	0	0	0	24,441	100.00
332	FIELD LINES	724,840	976	0	0	0	0	0	725,816	96.69
334	FIELD MEASURING AND REGULATING STATION EQUIPMENT	84,547	422	0	0	0	0	0	84,969	94.70
335	DRILLING AND CLEANING EQUIPMENT	49,463	20	0	0	0	0	0	49,483	99.76
337	OTHER EQUIPMENT	11,062	0	0	0	0	0	0	11,062	100.00
	TOTAL PRODUCTION PLANT	**1,250,732**	**1,469**	**(8,216)**	**0**	**0**	**0**	**0**	**1,243,985**	**105.14**
	STORAGE PLANT									
352.01	WELL CONSTRUCTION	(51,904)	0	15,970	0	0	0	0	(35,934)	0.00
	TOTAL STORAGE PLANT	**(51,904)**	**0**	**15,970**	**0**	**0**	**0**	**0**	**(35,934)**	**0.00**
	TRANSMISSION PLANT									
365.2	RIGHTS-OF-WAY	525,023	11,807	0	0	0	0	0	536,830	61.84
366	STRUCTURES AND IMPROVEMENTS	145,020	1,314	0	0	0	0	0	146,334	90.21
367	MAINS	21,426,794	461,079	332	0	0	0	0	21,888,205	56.02
369	MEASURING AND REGULATING STATION EQUIPMENT	3,870,923	94,131	933	0	0	0	0	3,965,987	64.46
370	COMMUNICATION EQUIPMENT	2,030,369	110,162	0	0	0	0	0	2,140,531	61.40
371	OTHER EQUIPMENT	128,356	1,209	0	0	0	0	0	129,565	92.13
371.1	TESTING EQUIPMENT	147,396	5,166	0	0	0	0	0	152,562	72.64
	TOTAL TRANSMISSION PLANT	**28,273,881**	**684,868**	**1,265**	**0**	**0**	**0**	**0**	**28,960,014**	**57.81**
	DISTRIBUTION PLANT									
374.2	RIGHTS-OF-WAY	1,334,545	46,434	0	0	0	0	0	1,380,979	38.96
375	STRUCTURES AND IMPROVEMENTS	3,158,924	89,878	7,019	0	0	0	0	3,255,821	58.62
376.1	MAINS - PRIMARILY STEEL	175,899,219	9,899,085	966,872	(260,912)	0	(244,266)	0	186,259,998	29.01
376.2	MAINS - CAST IRON	268,125	336,329	248,891	(364,752)	0	(470,895)	0	17,698	0.97
376.3	MAINS - PLASTIC	274,291,463	22,774,940	343,529	(5,565,107)	0	(1,287,209)	0	290,557,616	19.33
376.5	MAINS - PRIMARILY WROUGHT IRON	276,113	2,794	0	(15,273)	0	(19,717)	0	243,917	84.06
376.7	REG AFUDC	134,963	263,757	0	0	0	0	0	398,720	30.16
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	26,330,599	3,908,433	129,585	(3,311,668)	218,659	(656,781)	0	26,618,827	16.87
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	7,762,976	643,480	3,021	0	0	0	0	8,409,477	32.80
380	SERVICES	367,843,768	33,970,878	4,791,342	(6,926,792)	0	(3,574,917)	0	396,104,279	28.57
381	METERS	52,248,571	4,680,180	(2,368)	(1,717,529)	4,145	(1,589)	0	55,211,410	36.16
381.1	METERS - ERTS	18,643,419	721,773	0	0	0	0	0	19,365,192	83.29
382	METER INSTALLATIONS	33,970,679	2,430,768	508,390	(561,313)	0	(289,694)	0	36,058,830	34.80
383	HOUSE REGULATORS	5,524,689	216,688	966,993	(6,349)	0	(3,276)	0	6,698,745	62.81
384	HOUSE REGULATOR INSTALLATIONS	8,437,825	389,128	106,255	(24,046)	0	(12,410)	0	8,896,752	47.51
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	16,636,654	863,073	15,301	0	0	0	0	17,515,028	43.89
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES	(104,269)	10,069	0	0	0	0	0	(94,200)	-136.87
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	648,577	15,251	0	0	0	0	0	663,828	69.64
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,720	0	0	0	0	0	(15)	24,705	100.00
387	OTHER EQUIPMENT	2,825,275	105,603	1,510	0	0	0	0	2,932,388	60.20
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE	1,464,426	4,472	0	0	0	0	0	1,468,898	98.54
	TOTAL DISTRIBUTION PLANT	**997,621,261**	**81,373,013**	**8,086,340**	**(18,753,741)**	**222,804**	**(6,560,754)**	**(15)**	**1,061,988,908**	**26.01**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. BOOK RESERVE AT SEPTEMBER 30, 2021 PROJECTED TO SEPTEMBER 30, 2022

	ACCOUNT (1)	BOOK RESERVE AT BEGINNING OF YEAR (2)	ANNUAL ACCRUAL (3)	AMORTIZATION OF NET SALVAGE (4)	RETIREMENTS (5)	GROSS SALVAGE (6)	COST OF REMOVAL (7)	TRANSFERS AND ADJUSTMENTS (8)	BOOK RESERVE AT END OF YEAR (9)	BOOK RESERVE AS A PERCENT OF ORIGINAL COST (10)
GENERAL PLANT										
390.1	STRUCTURES AND IMPROVEMENTS	39,865,784	3,019,860	34,533	(657,344)	0	(65,735)	0	42,197,098	37.60
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	800,633	292,896	0	(85,045)	0	0	0	1,008,484	21.11
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	35,807	18,860	0	(6,467)	0	0	0	48,200	24.89
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	653,878	193,590	0	(356,493)	0	0	0	490,975	74.06
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	4,336,112	0	0	(4,378,298)	0	0	0	(42,186)	0.00
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	666,930	432,927	(6,642)	(206,230)	44,216	0	0	931,201	25.76
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	5,971,127	2,680,006	(203,409)	(1,539,083)	329,980	0	0	7,238,621	25.83
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	882,856	250,154	(16,312)	(150,551)	32,278	0	0	998,425	30.22
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	1,315,349	378,059	(6,635)	(234,720)	50,324	0	0	1,502,377	29.47
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	644,625	147,136	(25,692)	(98,485)	21,116	0	0	688,700	29.13
393	STORES EQUIPMENT	5,453	873	0	0	0	0	0	6,326	35.93
394	TOOLS, SHOP AND GARAGE EQUIPMENT	11,576,680	1,931,146	0	(684,358)	0	0	0	12,823,468	34.22
395	LABORATORY EQUIPMENT	90,041	22,108	0	0	0	0	0	112,149	25.62
396	POWER OPERATED EQUIPMENT	1,924,973	492,527	(487)	0	0	0	0	2,417,013	36.79
397	COMMUNICATION EQUIPMENT	373,200	111,509	0	(82,938)	0	0	0	401,771	42.80
398	MISCELLANEOUS EQUIPMENT	649,081	248,187	135,789	(143,552)	0	0	0	889,505	37.21
399	OTHER TANGIBLE PROPERTY	16,032	0	0	(16,032)	0	0	0	0	0.00
TOTAL GENERAL PLANT		**69,808,561**	**10,219,838**	**(88,855)**	**(8,639,596)**	**477,914**	**(65,735)**	**0**	**71,712,127**	**34.46**
TOTAL DEPRECIABLE GAS PLANT		**1,096,902,531**	**92,279,188**	**8,006,504**	**(27,393,337)**	**700,718**	**(6,626,489)**	**(15)**	**1,163,869,100**	**26.80**
OTHER UTILITY PLANT										
COMMON PLANT										
390.1	STRUCTURES AND IMPROVEMENTS	1,929,837	1,013,722	0	0	0	0	0	2,943,559	8.47
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	10,628	0	0	0	0	0	(10,628)	0	0.00
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	780,636	233,679	0	0	0	0	0	1,014,315	23.22
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	213,695	353,760	0	(51,353)	0	0	0	516,102	35.79
392.1	TRANSPORTATION EQUIPMENT - CARS	71,637	0	0	0	0	0	0	71,637	100.00
398	MISCELLANEOUS EQUIPMENT	669	3,211	0	0	0	0	0	3,880	13.87
TOTAL COMMON PLANT		**3,007,102**	**1,604,372**	**0**	**(51,353)**	**0**	**0**	**(10,628)**	**4,549,493**	**11.19**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 88.97%		**2,675,419**	**1,427,410**	**0**	**(45,689)**	**0**	**0**	**(9,456)**	**4,047,684**	
INFORMATION SERVICES (IS)										
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	33,595	1,631	0	(6,694)	0	0	0	28,532	94.66
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	12,938,845	3,713,290	0	(4,328,639)	0	0	0	12,323,496	70.11
391.2	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 5 YEARS	1,464,953	1,485,375	0	0	0	0	0	2,950,328	21.85
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	18,682,455	4,486,252	0	(12,553,923)	0	0	0	10,614,784	22.79
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	39,050,337	8,987,806	0	(5,571,339)	0	0	0	42,466,804	31.61
TOTAL INFORMATION SERVICES		**72,170,185**	**18,674,354**	**0**	**(22,460,595)**	**0**	**0**	**0**	**68,383,944**	**32.25**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 91.68%		**66,165,626**	**17,120,648**	**0**	**(20,591,873)**	**0**	**0**	**0**	**62,694,400**	
READING SERVICE CENTER										
390.1	STRUCTURES AND IMPROVEMENTS	1,472,986	86,979	0	0	0	0	0	1,559,965	70.48
LESS READING SERVICE CENTER ALLOCATED TO ELECTRIC DIVISION - 9.31%		**137,135**	**8,098**	**0**	**0**	**0**	**0**	**0**	**145,233**	
EMPIRE YARD BUILDING										
390.1	STRUCTURES AND IMPROVEMENTS	8,071,066	123,056	0	(25,917)	0	(2,592) #	0	8,165,613	57.82
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%		**1,054,888**	**16,083**	**0**	**(3,387)**	**0**	**(339)**	**0**	**1,067,246**	
TOTAL OTHER UTILITY PLANT ALLOCATED TO ALL GAS DIVISIONS		**67,649,022**	**18,523,877**	**0**	**(20,634,175)**	**0**	**339**	**(9,456)**	**65,529,605**	
TOTAL DEPRECIABLE PLANT IN SERVICE		**1,164,551,553**	**110,803,065**	**8,006,504**	**(48,027,512)**	**700,718**	**(6,626,150)**	**(9,471)**	**1,229,398,705**	

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2022

ACCOUNT (1)	BEGINNING OF YEAR BALANCE (2)	ADDITIONS (3)	RETIREMENTS (4)	TRANSFERS (5)	END OF YEAR BALANCE (6)	AVERAGE BALANCE (7)	ANNUAL ACCRUAL RATE (8)	ANNUAL ACCRUAL AMOUNT* (9)
GAS PLANT								
PRODUCTION PLANT								
305 MANUFACTURED GAS PLANT SITE REMEDIATION	0	0	0	0	0	0	-	0
325.2 PRODUCING LEASEHOLDS	163,100	0	0	0	163,100	163,100	0.02	33
325.4 RIGHTS-OF-WAY	30,277	0	0	0	30,277	30,277	0.06	18
328 FIELD MEASURING AND REGULATING STATION STRUCTURES	1,263	0	0	0	1,263	1,263	-	0
329 OTHER STRUCTURES	44,785	0	0	0	44,785	44,785	-	0
330 PRODUCING GAS WELLS - WELL CONSTRUCTION	18,209	0	0	0	18,209	18,209	-	0
331 PRODUCING GAS WELLS - WELL EQUIPMENT	24,441	0	0	0	24,441	24,441	-	0
332 FIELD LINES	750,689	0	0	0	750,689	750,689	0.13	976
334 FIELD MEASURING AND REGULATING STATION EQUIPMENT	89,725	0	0	0	89,725	89,725	0.47	422
335 DRILLING AND CLEANING EQUIPMENT	49,604	0	0	0	49,604	49,604	0.04	20
337 OTHER EQUIPMENT	11,062	0	0	0	11,062	11,062	-	0
TOTAL PRODUCTION PLANT	**1,183,155**	**0**	**0**	**0**	**1,183,155**	**1,183,155**		**1,469**
STORAGE PLANT								
352.01 WELL CONSTRUCTION	0	0	0	0	0	0	-	0
TOTAL STORAGE PLANT	**0**	**0**	**0**	**0**	**0**	**0**		**0**
TRANSMISSION PLANT								
365.2 RIGHTS-OF-WAY	868,160	0	0	0	868,160	868,160	1.36	11,807
366 STRUCTURES AND IMPROVEMENTS	162,216	0	0	0	162,216	162,216	0.81	1,314
367 MAINS	39,074,497	0	0	0	39,074,497	39,074,497	1.18	461,079
369 MEASURING AND REGULATING STATION EQUIPMENT	6,152,338	0	0	0	6,152,338	6,152,338	1.53	94,131
370 COMMUNICATION EQUIPMENT	3,486,136	0	0	0	3,486,136	3,486,136	3.16	110,162
371 OTHER EQUIPMENT	140,637	0	0	0	140,637	140,637	0.86	1,209
371.1 TESTING EQUIPMENT	210,011	0	0	0	210,011	210,011	2.46	5,166
TOTAL TRANSMISSION PLANT	**50,093,995**	**0**	**0**	**0**	**50,093,995**	**50,093,995**		**684,868**
DISTRIBUTION PLANT								
374.2 RIGHTS-OF-WAY	3,544,569	0	0	0	3,544,569	3,544,569	1.31	46,434
375 STRUCTURES AND IMPROVEMENTS	5,554,376	0	0	0	5,554,376	5,554,376	1.62	89,878
376.1 MAINS - PRIMARILY STEEL	637,160,499	5,123,390	(260,912)	0	642,022,976	639,591,738	1.55	9,899,085
376.2 MAINS - CAST IRON	2,188,512	0	(364,752)	0	1,823,760	2,006,136	16.77	336,329
376.3 MAINS - PLASTIC	1,287,145,663	221,355,625	(5,565,107)	0	1,502,936,181	1,395,040,922	1.63	22,774,940
376.5 MAINS - PRIMARILY WROUGHT IRON	305,458	0	(15,273)	0	290,185	297,822	0.94	2,794
376.7 REG AFUDC	1,322,088	0	0	0	1,322,088	1,322,088	19.95	263,757
378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	118,827,801	42,308,664	(3,311,668)	0	157,824,797	138,326,299	2.83	3,908,433
379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	25,635,909	0	0	0	25,635,909	25,635,909	2.51	643,480
380 SERVICES	1,321,300,624	72,015,092	(6,926,792)	0	1,386,388,924	1,353,844,774	2.51	33,970,878
381 METERS	143,350,208	11,056,942	(1,717,529)	0	152,689,621	148,019,915	3.16	4,680,180
381.1 METERS - ERTS	23,249,326	0	0	0	23,249,326	23,249,326	3.11	721,773
382 METER INSTALLATIONS	98,342,272	5,835,749	(561,313)	0	103,616,708	100,979,490	2.40	2,430,768
383 HOUSE REGULATORS	10,606,160	66,000	(6,349)	0	10,665,811	10,635,986	2.04	216,688
384 HOUSE REGULATOR INSTALLATIONS	18,501,668	250,000	(24,046)	0	18,727,622	18,614,645	2.09	389,128
385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	39,907,546	0	0	0	39,907,546	39,907,546	2.16	863,073
386.0 OTHER PROPERTY ON CUSTOMERS PREMISES	68,824	0	0	0	68,824	68,824	14.63	10,069
386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS	953,218	0	0	0	953,218	953,218	1.60	15,251
386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS	24,705	0	0	0	24,705	24,705	-	0
387 OTHER EQUIPMENT	4,871,243	0	0	0	4,871,243	4,871,243	2.17	105,603
387.1 OTHER EQUIPMENT - GRAPHIC DATA BASE	1,490,664	0	0	0	1,490,664	1,490,664	0.30	4,472
TOTAL DISTRIBUTION PLANT	**3,744,351,333**	**358,011,462**	**(18,753,741)**	**0**	**4,083,609,053**	**3,913,980,193**		**81,373,013**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2022

	ACCOUNT	BEGINNING OF YEAR BALANCE	ADDITIONS	RETIREMENTS	TRANSFERS	END OF YEAR BALANCE	AVERAGE BALANCE	ANNUAL ACCRUAL RATE	ANNUAL ACCRUAL AMOUNT*
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GENERAL PLANT									
390.1	STRUCTURES AND IMPROVEMENTS	105,260,872	7,624,127	(657,344)	0	112,227,655	108,744,263	4.17	3,019,860
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE	4,461,586	400,396	(85,045)	0	4,776,937	4,619,262	6.33	292,896
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	200,101	0	(6,467)	0	193,634	196,868	9.59	18,860
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT	1,019,470	0	(356,493)	0	662,977	841,224	20.68	193,590
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE	4,378,298	0	(4,378,298)	0	0	2,189,149	-	0
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S	2,708,878	1,112,219	(206,230)	0	3,614,867	3,161,873	13.67	432,927
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS	21,267,604	8,300,457	(1,539,083)	0	28,028,978	24,648,291	10.91	2,680,006
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES	2,642,994	811,937	(150,551)	0	3,304,380	2,973,687	8.42	250,154
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS	4,066,668	1,265,874	(234,720)	0	5,097,822	4,582,245	8.24	378,059
392.5	TRANSPORTATION EQUIPMENT - TRAILERS	1,931,903	531,142	(98,485)	0	2,364,560	2,148,232	6.93	147,136
393	STORES EQUIPMENT	17,606	0	0	0	17,606	17,606	4.96	873
394	TOOLS, SHOP AND GARAGE EQUIPMENT	33,689,953	4,473,264	(684,358)	0	37,478,859	35,584,406	5.45	1,931,146
395	LABORATORY EQUIPMENT	437,779	0	0	0	437,779	437,779	5.05	22,108
396	POWER OPERATED EQUIPMENT	6,570,611	0	0	0	6,570,611	6,570,611	7.49	492,527
397	COMMUNICATION EQUIPMENT	1,021,736	0	(82,938)	0	938,798	980,267	11.23	111,509
398	MISCELLANEOUS EQUIPMENT	2,355,656	178,274	(143,552)	0	2,390,378	2,373,017	10.40	248,187
399	OTHER TANGIBLE PROPERTY	16,032	0	(16,032)	0	0	8,016	-	0
TOTAL GENERAL PLANT		**192,047,747**	**24,697,690**	**(8,639,596)**	**0**	**208,105,841**	**200,076,794**		**10,219,838**
TOTAL DEPRECIABLE GAS PLANT		**3,987,676,230**	**382,709,152**	**(27,393,337)**	**0**	**4,342,992,044**	**4,165,334,137**		**92,279,188**
NONDEPRECIABLE PLANT									
301	ORGANIZATION	166,478	0	0	0	166,478	166,478		
302	FRANCHISES AND CONSENTS	193,597	0	0	0	193,597	193,597		
303	MISCELLANEOUS INTANGIBLE PLANT	289,868	0	0	0	289,868	289,868		
304.1	LAND AND LAND RIGHTS - LAND	375,198	0	0	0	375,198	375,198		
304.2	LAND AND LAND RIGHTS - LAND RIGHTS	6,454	0	0	0	6,454	6,454		
325.1	PRODUCING LANDS	13,029	0	0	0	13,029	13,029		
325.5	OTHER LAND	1,134	0	0	0	1,134	1,134		
365.1	LAND	47,323	0	0	0	47,323	47,323		
374.1	LAND AND LAND RIGHTS - LAND	849,347	0	0	0	849,347	849,347		
374.2	LAND AND LAND RIGHTS - LAND RIGHTS	7,305,824	0	0	0	7,305,824	7,305,824		
389.1	LAND AND LAND RIGHTS - LAND	10,369,472	0	0	0	10,369,472	10,369,472		
389.2	LAND AND LAND RIGHTS - LAND RIGHTS	1,313	0	0	0	1,313	1,313		
TOTAL NONDEPRECIABLE PLANT		**19,619,037**	**0**	**0**	**0**	**19,619,037**	**19,619,037**		
TOTAL GAS PLANT		**4,007,295,267**	**382,709,152**	**(27,393,337)**	**0**	**4,362,611,081**	**4,184,953,174**		

UGI UTILITIES, INC. - GAS DIVISION

TABLE 3. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2022

ACCOUNT (1)	BEGINNING OF YEAR BALANCE (2)	ADDITIONS (3)	RETIREMENTS (4)	TRANSFERS (5)	END OF YEAR BALANCE (6)	AVERAGE BALANCE (7)	ANNUAL ACCRUAL RATE (8)	ANNUAL ACCRUAL AMOUNT* (9)
OTHER UTILITY PLANT								
COMMON PLANT								
301 ORGANIZATION (NONDEPRECIABLE)	138,964	0	0	0	138,964	138,964		
389.1 LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)	6,947,108	0	0	0	6,947,108	6,947,108		
390.1 STRUCTURES AND IMPROVEMENTS	32,616,586	2,123,767	0	0	34,740,353	33,678,470	3.01	1,013,722
390.2 STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	0	0	0	0	0	0	-	0
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	4,367,824	0	0	0	4,367,824	4,367,824	5.35	233,679
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	1,493,560	0	(51,353)	0	1,442,207	1,467,884	24.10	353,760
392.1 TRANSPORTATION EQUIPMENT - CARS	71,637	0	0	0	71,637	71,637	-	0
398 MISCELLANEOUS EQUIPMENT	27,967	0	0	0	27,967	27,967	11.48	3,211
TOTAL COMMON PLANT	**45,663,646**	**2,123,767**	**(51,353)**	**0**	**47,736,060**	**46,699,853**		**1,604,372**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISION - 88.97%	**40,626,946**	**1,889,515**	**(45,689)**	**0**	**42,470,773**	**41,548,859**		**1,427,410**
INFORMATION SERVICES (IS)								
391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE	36,837	0	(6,694)	0	30,143	33,490	4.87	1,631
391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT	21,905,364	0	(4,328,639)	0	17,576,725	19,741,045	18.81	3,713,290
391.2 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 5 YEARS	13,499,682	0	0	0	13,499,682	13,499,682	11.00	1,485,375
391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS	45,912,815	13,214,701	(12,553,923)	0	46,573,593	46,243,204	8.57	4,486,252
391.4 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS	138,024,446	1,880,199	(5,571,339)	0	134,333,306	136,178,876	6.60	8,987,806
TOTAL INFORMATION SERVICES	**219,379,144**	**15,094,900**	**(22,460,595)**	**0**	**212,013,449**	**215,696,297**		**18,674,354**
TOTAL INFORMATION SERVICES ALLOCATED TO GAS DIVISION - 91.68%	**201,126,799**	**13,839,004**	**(20,591,873)**	**0**	**194,373,930**	**197,750,365**		**17,120,648**
READING SERVICE CENTER								
390.1 STRUCTURES AND IMPROVEMENTS	2,213,194	0	0	0	2,213,194	2,213,194	3.51	86,979
LESS READING SERVICE CENTER ALLOCATED TO ELECTRIC DIVISION - 9.31%	**206,048**	**0**	**0**	**0**	**206,048**	**206,048**		**8,098**
EMPIRE YARD BUILDING								
390.1 STRUCTURES AND IMPROVEMENTS	13,889,132	259,172	(25,917)	0	14,122,387	14,005,760	0.88	123,056
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%	**1,815,310**	**33,874**	**(3,387)**	**0**	**1,845,796**	**1,830,553**		**16,083**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ALL GAS DIVISIONS	**239,732,387**	**15,694,645**	**(20,634,175)**	**0**	**234,792,859**	**237,262,623**		**18,523,877**
TOTAL PLANT IN SERVICE	**4,247,027,654**	**398,403,797**	**(48,027,512)**	**0**	**4,597,403,940**	**4,422,215,797**		**110,803,065**

* TOTAL ACCRUALS SHOWN ARE BASED ON EACH DIVISION'S AVERAGE BALANCES

UGI UTILITIES, INC. - GAS DIVISION

TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

ACCOUNT	2018 GROSS SALVAGE	2018 COST OF REMOVAL	2019 GROSS SALVAGE	2019 COST OF REMOVAL	2020 GROSS SALVAGE	2020 COST OF REMOVAL	2021 GROSS SALVAGE	2021 COST OF REMOVAL	2022 GROSS SALVAGE	2022 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GAS PLANT												
PRODUCTION PLANT												
305	0	(6)	0	0	0	0	(115,195)	0	0	0	(115,201)	(23,040)
325.2	0	0	0	0	0	0	0	0	0	0	0	0
325.4	0	0	0	0	0	0	0	0	0	0	0	0
328	0	0	0	0	0	0	0	0	0	0	0	0
329	0	0	0	0	0	0	0	0	0	0	0	0
330	0	0	0	0	0	0	0	0	0	0	0	0
331	0	0	0	0	0	0	0	0	0	0	0	0
332	0	0	0	0	0	0	0	0	0	0	0	0
334	0	0	0	0	0	0	0	0	0	0	0	0
335	0	0	0	0	0	0	0	0	0	0	0	0
337	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**(6)**	**0**	**0**	**0**	**0**	**(115,195)**	**0**	**0**	**0**	**(115,201)**	**(23,040)**
STORAGE PLANT												
352.01	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TRANSMISSION PLANT												
365.2	0	0	0	0	0	0	0	0	0	0	0	0
366	0	0	0	0	0	0	0	0	0	0	0	0
367	0	0	0	0	0	0	0	1,660	0	0	1,660	332
369	0	1,147	0	131	0	0	0	3,386	0	0	4,664	933
370	0	0	0	0	0	0	0	0	0	0	0	0
371	0	0	0	0	0	0	0	0	0	0	0	0
371.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**1,147**	**0**	**131**	**0**	**0**	**0**	**5,046**	**0**	**0**	**6,324**	**1,265**
DISTRIBUTION PLANT												
374.2	0	0	0	0	0	0	0	0	0	0	0	0
375	0	(184)	0	0	0	0	0	0	0	0	(184)	(37)
376.1	4,146	1,112,569	(23,558)	527,144	0	422,998	0	1,712,927	0	244,266	4,000,492	800,098
376.2	0	545,838	0	(284,507)	0	529,595	0	92,247	0	470,895	1,354,068	270,814
376.3	0	365,481	0	197,897	0	77,475	0	728,986	0	1,287,209	2,657,048	531,410
376.5	0	0	0	0	0	0	0	0	0	19,717	19,717	3,943
378	(216,520)	339,196	(54,593)	154,135	0	29,723	0	168,692	(218,659)	656,781	858,755	171,751
379	0	0	0	0	0	0	0	15,105	0	0	15,105	3,021
380	0	5,717,004	0	3,425,191	0	4,911,297	0	4,191,361	0	3,574,917	21,819,770	4,363,954
381	0	3,138	0	770	0	0	(19,201)	1,237	(4,145)	1,589	(16,612)	(3,322)
381.1	0	0	0	0	0	0	0	0	0	0	0	0
382	0	328,078	0	262,633	0	1,144,545	0	224,823	0	289,694	2,249,773	449,955
383	0	1,356,927	0	(54,424)	0	2,130	0	269	0	3,276	1,308,178	261,636
384	0	688	0	(2)	0	515,427	0	13,720	0	12,410	542,243	108,449
385	0	25,192	0	4,047	0	0	0	35,290	0	0	64,529	12,906
386.0	0	0	0	0	0	0	0	0	0	0	0	0
386.1	0	0	0	0	0	0	0	0	0	0	0	0
386.2	0	0	0	0	0	0	0	0	0	0	0	0
386.3	0	0	0	0	0	0	0	0	0	0	0	0
387	0	0	0	0	0	0	0	0	0	0	0	0
387.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**(212,374)**	**9,793,927**	**(78,151)**	**4,232,884**	**0**	**7,633,190**	**(19,201)**	**7,184,657**	**(222,804)**	**6,560,754**	**34,872,882**	**6,974,578**

UGI UTILITIES, INC. - GAS DIVISION

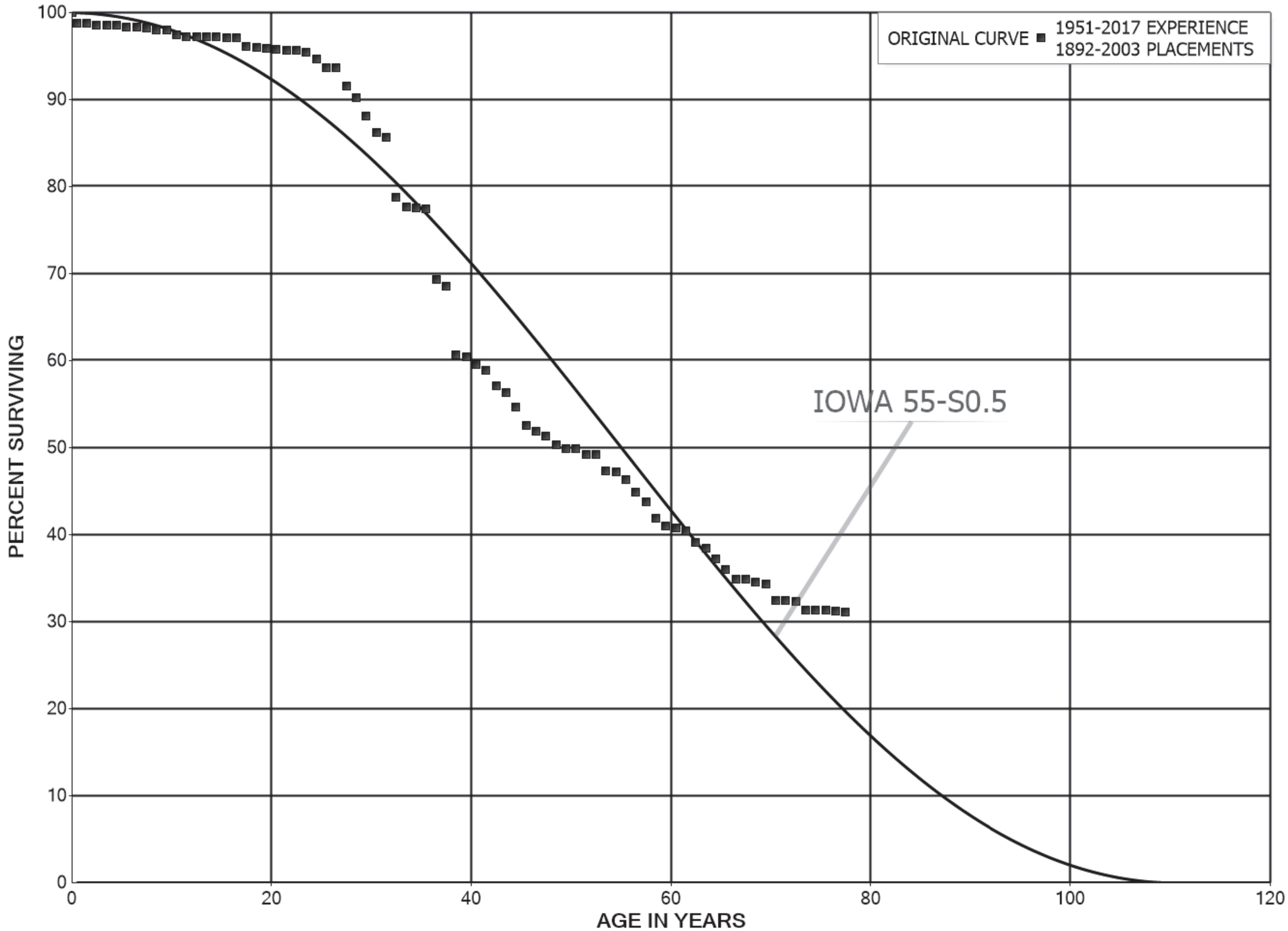
TABLE 4. AMORTIZATION OF EXPERIENCED AND ESTIMATED NET SALVAGE

ACCOUNT	2018 GROSS SALVAGE	2018 COST OF REMOVAL	2019 GROSS SALVAGE	2019 COST OF REMOVAL	2020 GROSS SALVAGE	2020 COST OF REMOVAL	2021 GROSS SALVAGE	2021 COST OF REMOVAL	2022 GROSS SALVAGE	2022 COST OF REMOVAL	FIVE YEAR NET SALVAGE TOTAL	NET SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GENERAL PLANT												
390.1	0	(705)	0	76,973	0	17,949	0	135	0	65,735	160,087	32,017
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	7	0	0	(30,492)	0	0	0	(44,216)	0	(74,701)	(14,940)
392.2	0	101	0	0	(449,978)	0	(526,894)	0	(329,980)	0	(1,306,751)	(261,350)
392.3	0	42	0	0	(64,698)	0	0	0	(32,278)	0	(96,934)	(19,387)
392.4	0	37	0	0	(18,471)	0	0	0	(50,324)	0	(68,758)	(13,752)
392.5	0	3	0	0	(127,432)	0	0	0	(21,116)	0	(148,545)	(29,709)
393	0	0	0	0	0	0	0	0	0	0	0	0
394	0	0	0	0	0	0	0	0	0	0	0	0
395	0	0	0	0	0	0	0	0	0	0	0	0
396	0	0	0	0	0	0	0	0	0	0	0	0
397	0	0	0	0	0	0	0	0	0	0	0	0
398	0	3,075	0	652	0	257,300	0	391,820	0	0	652,847	130,569
TOTAL	**0**	**2,559**	**0**	**77,625**	**(691,071)**	**275,249**	**(526,894)**	**391,955**	**(477,914)**	**65,735**	**(882,756)**	**(176,552)**
TOTAL GAS PLANT	**(212,374)**	**9,797,627**	**(78,151)**	**4,310,640**	**(691,071)**	**7,908,439**	**(661,290)**	**7,581,658**	**(700,718)**	**6,626,489**	**33,881,249**	**6,776,251**
OTHER UTILITY PLANT												
COMMON PLANT												
390.1	0	0	0	0	0	0	0	0	0	0	0	0
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
INFORMATION SERVICES												
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
GRAND TOTAL	**(212,374)**	**9,797,627**	**(78,151)**	**4,310,640**	**(691,071)**	**7,908,439**	**(661,290)**	**7,581,658**	**(700,718)**	**6,626,489**	**33,881,249**	**6,776,251**

* COLUMN (12) EQUALS THE SUMMATION OF COLUMNS (2) THROUGH (11).

PART VI. SERVICE LIFE STATISTICS

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 325.2 PRODUCING LEASEHOLDS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.2 PRODUCING LEASEHOLDS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1892-2003 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	15,696	198	0.0126	0.9874	100.00
0.5	15,545		0.0000	1.0000	98.74
1.5	15,436	30	0.0020	0.9980	98.74
2.5	15,513		0.0000	1.0000	98.55
3.5	15,514		0.0000	1.0000	98.55
4.5	15,665	44	0.0028	0.9972	98.55
5.5	16,891		0.0000	1.0000	98.27
6.5	17,075	21	0.0012	0.9988	98.27
7.5	19,938	40	0.0020	0.9980	98.15
8.5	19,915		0.0000	1.0000	97.95
9.5	19,915	116	0.0058	0.9942	97.95
10.5	36,437	75	0.0021	0.9979	97.38
11.5	36,079		0.0000	1.0000	97.18
12.5	36,094		0.0000	1.0000	97.18
13.5	36,095		0.0000	1.0000	97.18
14.5	35,049	56	0.0016	0.9984	97.18
15.5	35,011		0.0000	1.0000	97.02
16.5	37,221	378	0.0101	0.9899	97.02
17.5	36,843	31	0.0008	0.9992	96.04
18.5	36,841	49	0.0013	0.9987	95.96
19.5	36,792	53	0.0014	0.9986	95.83
20.5	33,195	9	0.0003	0.9997	95.69
21.5	33,593		0.0000	1.0000	95.66
22.5	35,720	110	0.0031	0.9969	95.66
23.5	44,302	332	0.0075	0.9925	95.37
24.5	44,229	495	0.0112	0.9888	94.65
25.5	50,688		0.0000	1.0000	93.59
26.5	51,649	1,166	0.0226	0.9774	93.59
27.5	52,833	779	0.0147	0.9853	91.48
28.5	51,796	1,185	0.0229	0.9771	90.13
29.5	60,774	1,287	0.0212	0.9788	88.07
30.5	63,464	445	0.0070	0.9930	86.20
31.5	67,550	5,425	0.0803	0.9197	85.60
32.5	72,008	980	0.0136	0.9864	78.72
33.5	75,459	185	0.0025	0.9975	77.65
34.5	81,907	52	0.0006	0.9994	77.46
35.5	81,854	8,648	0.1057	0.8943	77.41
36.5	73,357	731	0.0100	0.9900	69.23
37.5	74,491	8,646	0.1161	0.8839	68.54
38.5	111,963	392	0.0035	0.9965	60.59

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.2 PRODUCING LEASEHOLDS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1892-2003 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	124,474	1,844	0.0148	0.9852	60.38
40.5	124,278	1,327	0.0107	0.9893	59.48
41.5	125,637	3,902	0.0311	0.9689	58.85
42.5	126,800	1,688	0.0133	0.9867	57.02
43.5	129,467	3,803	0.0294	0.9706	56.26
44.5	131,576	4,974	0.0378	0.9622	54.61
45.5	138,391	1,760	0.0127	0.9873	52.54
46.5	179,837	2,060	0.0115	0.9885	51.87
47.5	191,853	3,770	0.0197	0.9803	51.28
48.5	201,733	1,676	0.0083	0.9917	50.27
49.5	218,250	115	0.0005	0.9995	49.85
50.5	238,512	2,893	0.0121	0.9879	49.83
51.5	240,605	310	0.0013	0.9987	49.22
52.5	276,900	10,848	0.0392	0.9608	49.16
53.5	273,446	239	0.0009	0.9991	47.23
54.5	273,206	5,551	0.0203	0.9797	47.19
55.5	267,645	7,798	0.0291	0.9709	46.23
56.5	262,450	6,718	0.0256	0.9744	44.89
57.5	256,175	11,283	0.0440	0.9560	43.74
58.5	246,867	5,166	0.0209	0.9791	41.81
59.5	241,559	1,535	0.0064	0.9936	40.94
60.5	240,023	1,666	0.0069	0.9931	40.68
61.5	238,355	7,919	0.0332	0.9668	40.39
62.5	230,428	3,914	0.0170	0.9830	39.05
63.5	226,514	7,003	0.0309	0.9691	38.39
64.5	219,473	7,072	0.0322	0.9678	37.20
65.5	212,402	6,577	0.0310	0.9690	36.00
66.5	205,825	232	0.0011	0.9989	34.89
67.5	205,593	1,973	0.0096	0.9904	34.85
68.5	203,439	1,317	0.0065	0.9935	34.52
69.5	202,122	11,365	0.0562	0.9438	34.29
70.5	190,754	116	0.0006	0.9994	32.36
71.5	190,638	401	0.0021	0.9979	32.34
72.5	189,607	5,498	0.0290	0.9710	32.28
73.5	178,451		0.0000	1.0000	31.34
74.5	176,229		0.0000	1.0000	31.34
75.5	176,229	1,082	0.0061	0.9939	31.34
76.5	175,147	599	0.0034	0.9966	31.15
77.5	159,323		0.0000	1.0000	31.04
78.5	159,309		0.0000	1.0000	31.04

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.2 PRODUCING LEASEHOLDS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1892-2003 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	159,294		0.0000	1.0000	31.04
80.5	159,294	3,072	0.0193	0.9807	31.04
81.5	156,169		0.0000	1.0000	30.44
82.5	156,169		0.0000	1.0000	30.44
83.5	155,218		0.0000	1.0000	30.44
84.5	155,218	1,172	0.0076	0.9924	30.44
85.5	154,046		0.0000	1.0000	30.21
86.5	154,046		0.0000	1.0000	30.21
87.5	154,046		0.0000	1.0000	30.21
88.5	154,046		0.0000	1.0000	30.21
89.5	153,084		0.0000	1.0000	30.21
90.5	151,648	4,518	0.0298	0.9702	30.21
91.5	147,130	11,926	0.0811	0.9189	29.31
92.5	131,157		0.0000	1.0000	26.94
93.5	131,157	1,108	0.0084	0.9916	26.94
94.5	130,049		0.0000	1.0000	26.71
95.5	130,048	869	0.0067	0.9933	26.71
96.5	129,179	3,114	0.0241	0.9759	26.53
97.5	123,072		0.0000	1.0000	25.89
98.5	123,072		0.0000	1.0000	25.89
99.5	121,098		0.0000	1.0000	25.89
100.5	120,396		0.0000	1.0000	25.89
101.5	119,196		0.0000	1.0000	25.89
102.5	119,196		0.0000	1.0000	25.89
103.5	119,196		0.0000	1.0000	25.89
104.5	118,055		0.0000	1.0000	25.89
105.5	86,138		0.0000	1.0000	25.89
106.5	83,444		0.0000	1.0000	25.89
107.5	82,918		0.0000	1.0000	25.89
108.5	82,918		0.0000	1.0000	25.89
109.5	80,977		0.0000	1.0000	25.89
110.5	80,902		0.0000	1.0000	25.89
111.5	80,431		0.0000	1.0000	25.89
112.5	78,750		0.0000	1.0000	25.89
113.5	35,661		0.0000	1.0000	25.89
114.5	27,440		0.0000	1.0000	25.89
115.5	27,440		0.0000	1.0000	25.89
116.5	22,949		0.0000	1.0000	25.89
117.5	22,201		0.0000	1.0000	25.89
118.5	21,156		0.0000	1.0000	25.89

UGI UTILITIES, INC. - GAS DIVISION

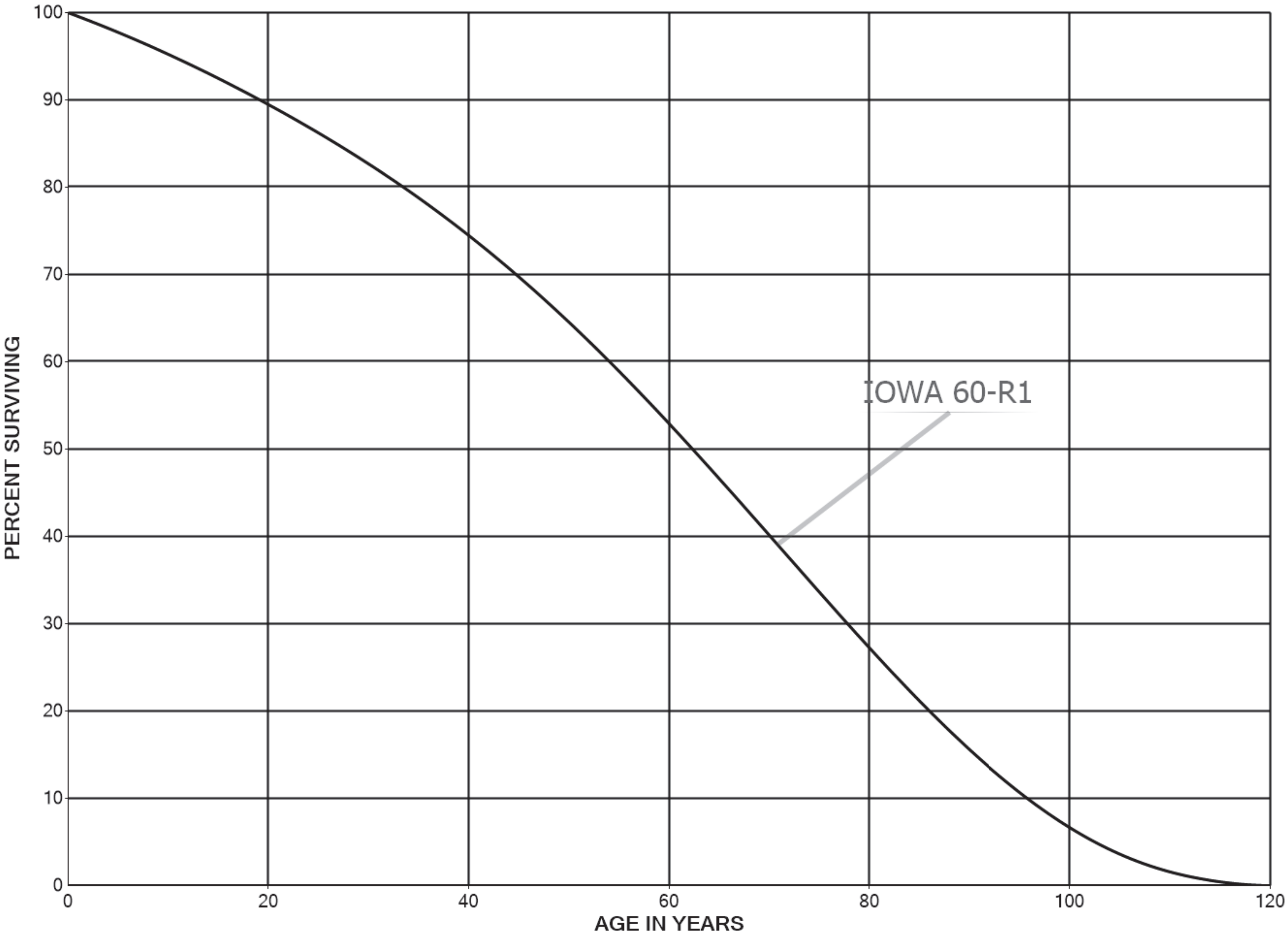
ACCOUNT 325.2 PRODUCING LEASEHOLDS

ORIGINAL LIFE TABLE, CONT.

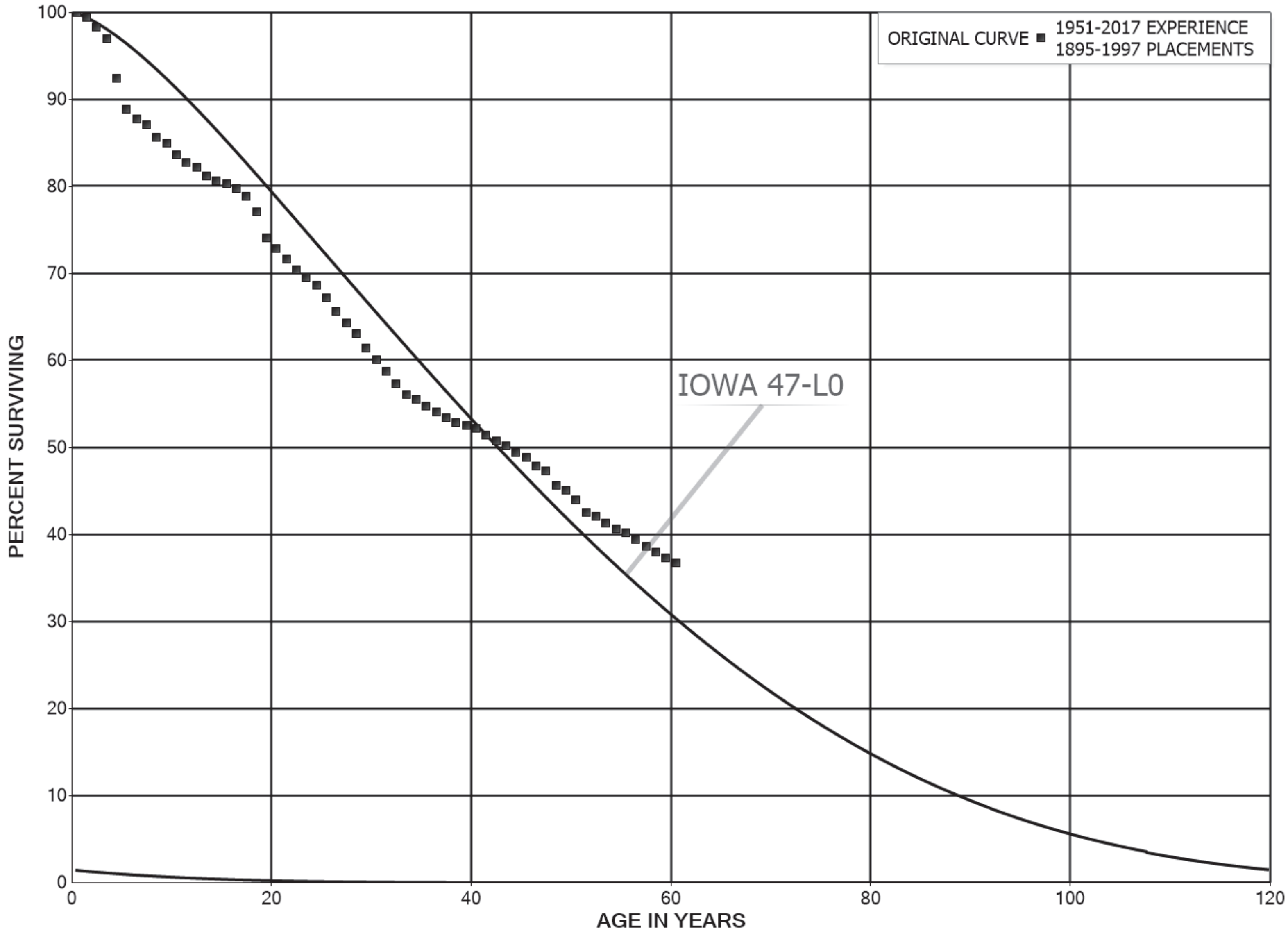
PLACEMENT BAND 1892-2003 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	7,769		0.0000	1.0000	25.89
120.5	4,147		0.0000	1.0000	25.89
121.5	4,147		0.0000	1.0000	25.89
122.5	4,147		0.0000	1.0000	25.89
123.5	1,497		0.0000	1.0000	25.89
124.5	1,497		0.0000	1.0000	25.89
125.5					25.89

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 325.4 RIGHTS-OF-WAY
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 332 FIELD LINES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1895-1997 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	995,099	706	0.0007	0.9993	100.00
0.5	994,413	5,190	0.0052	0.9948	99.93
1.5	1,002,567	11,571	0.0115	0.9885	99.41
2.5	1,068,219	14,039	0.0131	0.9869	98.26
3.5	1,069,963	50,316	0.0470	0.9530	96.97
4.5	959,123	36,859	0.0384	0.9616	92.41
5.5	854,782	10,823	0.0127	0.9873	88.86
6.5	873,649	6,699	0.0077	0.9923	87.73
7.5	872,519	14,434	0.0165	0.9835	87.06
8.5	867,886	6,491	0.0075	0.9925	85.62
9.5	890,102	13,916	0.0156	0.9844	84.98
10.5	946,617	10,365	0.0109	0.9891	83.65
11.5	939,495	6,410	0.0068	0.9932	82.73
12.5	928,987	11,666	0.0126	0.9874	82.17
13.5	908,468	6,450	0.0071	0.9929	81.14
14.5	897,181	2,627	0.0029	0.9971	80.56
15.5	900,846	6,884	0.0076	0.9924	80.33
16.5	897,781	10,145	0.0113	0.9887	79.71
17.5	889,115	19,542	0.0220	0.9780	78.81
18.5	871,420	34,502	0.0396	0.9604	77.08
19.5	838,954	12,973	0.0155	0.9845	74.03
20.5	786,703	13,837	0.0176	0.9824	72.88
21.5	777,581	13,075	0.0168	0.9832	71.60
22.5	775,234	9,858	0.0127	0.9873	70.40
23.5	792,187	10,532	0.0133	0.9867	69.50
24.5	815,815	16,148	0.0198	0.9802	68.58
25.5	821,292	20,125	0.0245	0.9755	67.22
26.5	820,944	16,102	0.0196	0.9804	65.57
27.5	890,431	17,441	0.0196	0.9804	64.29
28.5	889,829	22,845	0.0257	0.9743	63.03
29.5	883,917	19,018	0.0215	0.9785	61.41
30.5	878,990	19,549	0.0222	0.9778	60.09
31.5	884,213	22,351	0.0253	0.9747	58.75
32.5	883,535	19,009	0.0215	0.9785	57.27
33.5	883,149	7,501	0.0085	0.9915	56.03
34.5	893,947	12,933	0.0145	0.9855	55.56
35.5	910,301	11,431	0.0126	0.9874	54.76
36.5	917,730	11,333	0.0123	0.9877	54.07
37.5	937,459	10,209	0.0109	0.9891	53.40
38.5	971,921	6,474	0.0067	0.9933	52.82

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-1997 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	974,718	5,592	0.0057	0.9943	52.47
40.5	977,616	15,294	0.0156	0.9844	52.17
41.5	956,611	12,228	0.0128	0.9872	51.35
42.5	957,836	10,427	0.0109	0.9891	50.69
43.5	1,001,216	15,345	0.0153	0.9847	50.14
44.5	1,009,685	11,530	0.0114	0.9886	49.37
45.5	976,609	19,522	0.0200	0.9800	48.81
46.5	987,411	11,474	0.0116	0.9884	47.83
47.5	974,226	33,501	0.0344	0.9656	47.28
48.5	967,111	11,846	0.0122	0.9878	45.65
49.5	953,894	24,417	0.0256	0.9744	45.09
50.5	923,089	29,459	0.0319	0.9681	43.94
51.5	903,763	10,384	0.0115	0.9885	42.54
52.5	893,967	16,709	0.0187	0.9813	42.05
53.5	853,195	12,308	0.0144	0.9856	41.26
54.5	820,408	9,435	0.0115	0.9885	40.67
55.5	796,390	15,747	0.0198	0.9802	40.20
56.5	767,852	15,084	0.0196	0.9804	39.40
57.5	746,640	13,995	0.0187	0.9813	38.63
58.5	723,148	12,436	0.0172	0.9828	37.91
59.5	702,024	10,220	0.0146	0.9854	37.25
60.5	672,792	12,023	0.0179	0.9821	36.71
61.5	649,522	14,679	0.0226	0.9774	36.06
62.5	627,085	12,608	0.0201	0.9799	35.24
63.5	607,056	12,077	0.0199	0.9801	34.53
64.5	552,779	8,006	0.0145	0.9855	33.84
65.5	544,288	24,660	0.0453	0.9547	33.35
66.5	512,497	8,739	0.0171	0.9829	31.84
67.5	502,344	3,663	0.0073	0.9927	31.30
68.5	448,090	10,555	0.0236	0.9764	31.07
69.5	383,952	5,106	0.0133	0.9867	30.34
70.5	376,246	11,232	0.0299	0.9701	29.94
71.5	354,331	7,754	0.0219	0.9781	29.04
72.5	337,766	5,100	0.0151	0.9849	28.41
73.5	327,624	3,265	0.0100	0.9900	27.98
74.5	318,440	2,105	0.0066	0.9934	27.70
75.5	312,863	1,422	0.0045	0.9955	27.52
76.5	303,054	4,004	0.0132	0.9868	27.39
77.5	244,062	2,855	0.0117	0.9883	27.03
78.5	220,274	1,291	0.0059	0.9941	26.71

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-1997 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	212,708	1,058	0.0050	0.9950	26.56
80.5	209,934	88	0.0004	0.9996	26.43
81.5	209,256	1,456	0.0070	0.9930	26.41
82.5	207,144	906	0.0044	0.9956	26.23
83.5	205,504	3,261	0.0159	0.9841	26.12
84.5	200,809	1,136	0.0057	0.9943	25.70
85.5	199,378	2,787	0.0140	0.9860	25.56
86.5	196,306	1,305	0.0067	0.9933	25.20
87.5	189,041	358	0.0019	0.9981	25.03
88.5	187,861	11,282	0.0601	0.9399	24.98
89.5	175,332	5,720	0.0326	0.9674	23.48
90.5	169,111	1,112	0.0066	0.9934	22.72
91.5	159,029	1,051	0.0066	0.9934	22.57
92.5	157,132		0.0000	1.0000	22.42
93.5	153,550	2,160	0.0141	0.9859	22.42
94.5	124,869		0.0000	1.0000	22.10
95.5	123,672		0.0000	1.0000	22.10
96.5	118,719	36	0.0003	0.9997	22.10
97.5	117,132		0.0000	1.0000	22.10
98.5	105,321		0.0000	1.0000	22.10
99.5	102,156		0.0000	1.0000	22.10
100.5	102,067		0.0000	1.0000	22.10
101.5	97,200		0.0000	1.0000	22.10
102.5	90,985		0.0000	1.0000	22.10
103.5	86,348		0.0000	1.0000	22.10
104.5	80,039		0.0000	1.0000	22.10
105.5	74,446		0.0000	1.0000	22.10
106.5	72,127		0.0000	1.0000	22.10
107.5	69,695		0.0000	1.0000	22.10
108.5	69,387		0.0000	1.0000	22.10
109.5	66,525		0.0000	1.0000	22.10
110.5	63,373		0.0000	1.0000	22.10
111.5	57,013		0.0000	1.0000	22.10
112.5	56,500		0.0000	1.0000	22.10
113.5	55,224		0.0000	1.0000	22.10
114.5	40,408		0.0000	1.0000	22.10
115.5	26,749		0.0000	1.0000	22.10
116.5	17,096		0.0000	1.0000	22.10
117.5	14,113		0.0000	1.0000	22.10
118.5	6,998		0.0000	1.0000	22.10

UGI UTILITIES, INC. - GAS DIVISION

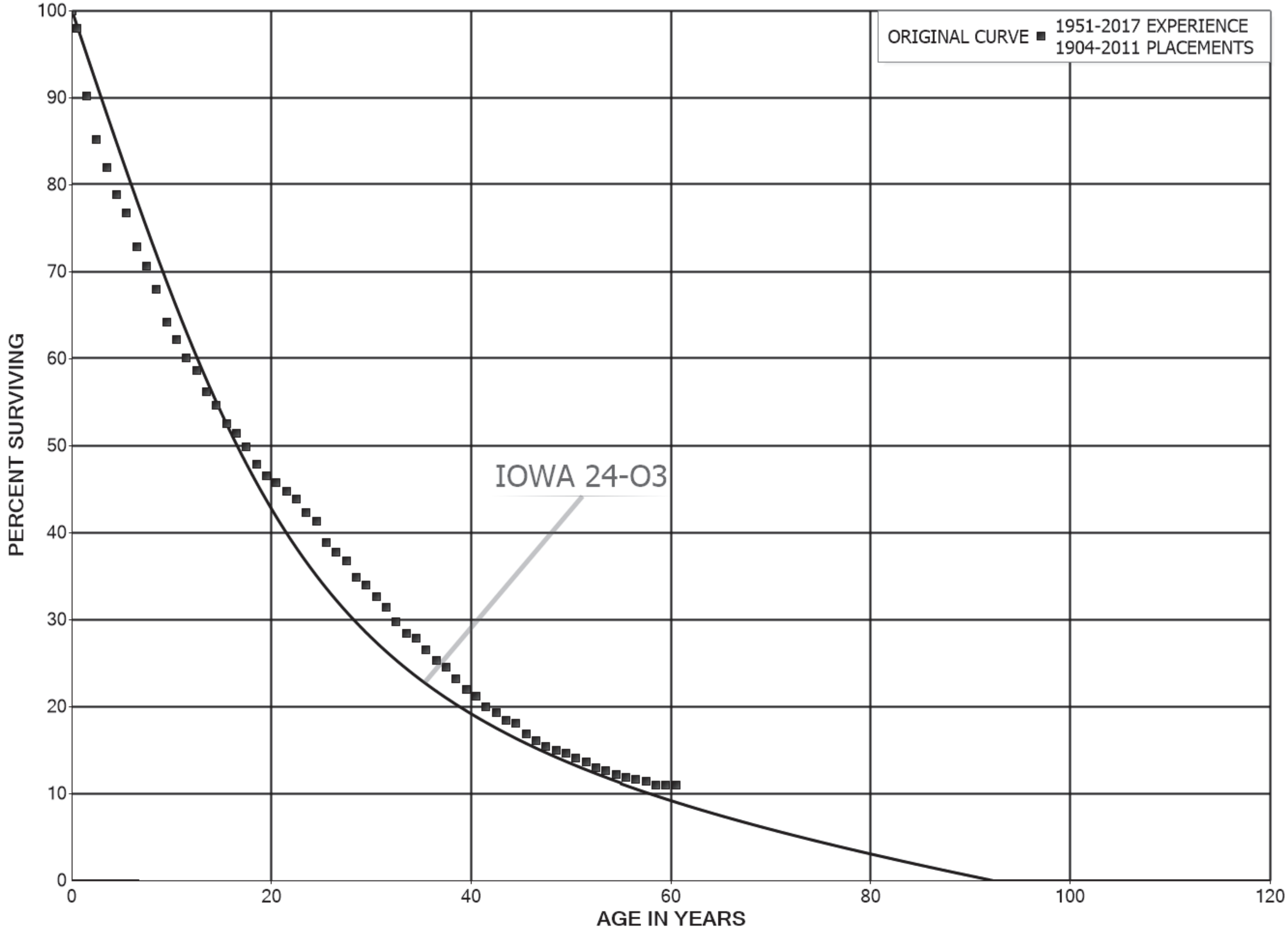
ACCOUNT 332 FIELD LINES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-1997 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	17		0.0000	1.0000	22.10
120.5	17		0.0000	1.0000	22.10
121.5	17		0.0000	1.0000	22.10
122.5					22.10

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	269,294	5,560	0.0206	0.9794	100.00
0.5	220,203	17,353	0.0788	0.9212	97.94
1.5	205,078	11,561	0.0564	0.9436	90.22
2.5	201,048	7,466	0.0371	0.9629	85.13
3.5	202,006	7,730	0.0383	0.9617	81.97
4.5	199,114	5,443	0.0273	0.9727	78.83
5.5	172,528	8,628	0.0500	0.9500	76.68
6.5	161,938	4,909	0.0303	0.9697	72.84
7.5	161,175	6,157	0.0382	0.9618	70.64
8.5	159,819	8,821	0.0552	0.9448	67.94
9.5	154,662	4,805	0.0311	0.9689	64.19
10.5	136,805	4,768	0.0349	0.9651	62.19
11.5	129,908	3,095	0.0238	0.9762	60.03
12.5	127,246	5,200	0.0409	0.9591	58.60
13.5	124,170	3,522	0.0284	0.9716	56.20
14.5	121,872	4,741	0.0389	0.9611	54.61
15.5	119,023	2,588	0.0217	0.9783	52.48
16.5	114,326	3,269	0.0286	0.9714	51.34
17.5	111,430	4,544	0.0408	0.9592	49.87
18.5	111,363	3,046	0.0274	0.9726	47.84
19.5	108,351	1,797	0.0166	0.9834	46.53
20.5	108,177	2,330	0.0215	0.9785	45.76
21.5	103,974	2,149	0.0207	0.9793	44.77
22.5	103,337	3,641	0.0352	0.9648	43.85
23.5	102,271	2,590	0.0253	0.9747	42.30
24.5	82,619	4,749	0.0575	0.9425	41.23
25.5	74,534	2,171	0.0291	0.9709	38.86
26.5	68,016	1,847	0.0272	0.9728	37.73
27.5	66,860	3,433	0.0513	0.9487	36.71
28.5	63,193	1,667	0.0264	0.9736	34.82
29.5	62,433	2,288	0.0367	0.9633	33.90
30.5	59,773	2,271	0.0380	0.9620	32.66
31.5	52,526	2,823	0.0537	0.9463	31.42
32.5	48,206	2,146	0.0445	0.9555	29.73
33.5	47,098	1,011	0.0215	0.9785	28.41
34.5	47,162	2,251	0.0477	0.9523	27.80
35.5	45,498	1,949	0.0428	0.9572	26.47
36.5	44,198	1,372	0.0310	0.9690	25.34
37.5	42,520	2,402	0.0565	0.9435	24.55
38.5	39,924	2,058	0.0516	0.9484	23.16

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	36,867	1,276	0.0346	0.9654	21.97
40.5	36,251	2,227	0.0614	0.9386	21.21
41.5	34,405	1,016	0.0295	0.9705	19.91
42.5	33,331	1,507	0.0452	0.9548	19.32
43.5	31,123	699	0.0225	0.9775	18.45
44.5	30,541	2,083	0.0682	0.9318	18.03
45.5	28,155	1,225	0.0435	0.9565	16.80
46.5	27,133	1,153	0.0425	0.9575	16.07
47.5	26,066	825	0.0316	0.9684	15.39
48.5	25,196	424	0.0168	0.9832	14.90
49.5	22,213	904	0.0407	0.9593	14.65
50.5	21,375	587	0.0275	0.9725	14.05
51.5	19,272	939	0.0487	0.9513	13.67
52.5	18,348	469	0.0256	0.9744	13.00
53.5	17,579	740	0.0421	0.9579	12.67
54.5	16,681	339	0.0203	0.9797	12.14
55.5	12,330	233	0.0189	0.9811	11.89
56.5	11,082	224	0.0203	0.9797	11.66
57.5	10,858	445	0.0410	0.9590	11.43
58.5	10,412		0.0000	1.0000	10.96
59.5	10,317		0.0000	1.0000	10.96
60.5	10,317		0.0000	1.0000	10.96
61.5	10,030	295	0.0294	0.9706	10.96
62.5	9,735		0.0000	1.0000	10.64
63.5	9,735	90	0.0092	0.9908	10.64
64.5	9,645	100	0.0103	0.9897	10.54
65.5	7,738		0.0000	1.0000	10.43
66.5	2,533	144	0.0569	0.9431	10.43
67.5	2,389		0.0000	1.0000	9.84
68.5	2,079	26	0.0126	0.9874	9.84
69.5	1,982	86	0.0431	0.9569	9.71
70.5	1,520		0.0000	1.0000	9.29
71.5	1,453		0.0000	1.0000	9.29
72.5	1,304		0.0000	1.0000	9.29
73.5	1,141		0.0000	1.0000	9.29
74.5	1,141	125	0.1097	0.8903	9.29
75.5	950		0.0000	1.0000	8.28
76.5	886		0.0000	1.0000	8.28
77.5	369	45	0.1219	0.8781	8.28
78.5	324		0.0000	1.0000	7.27

UGI UTILITIES, INC. - GAS DIVISION

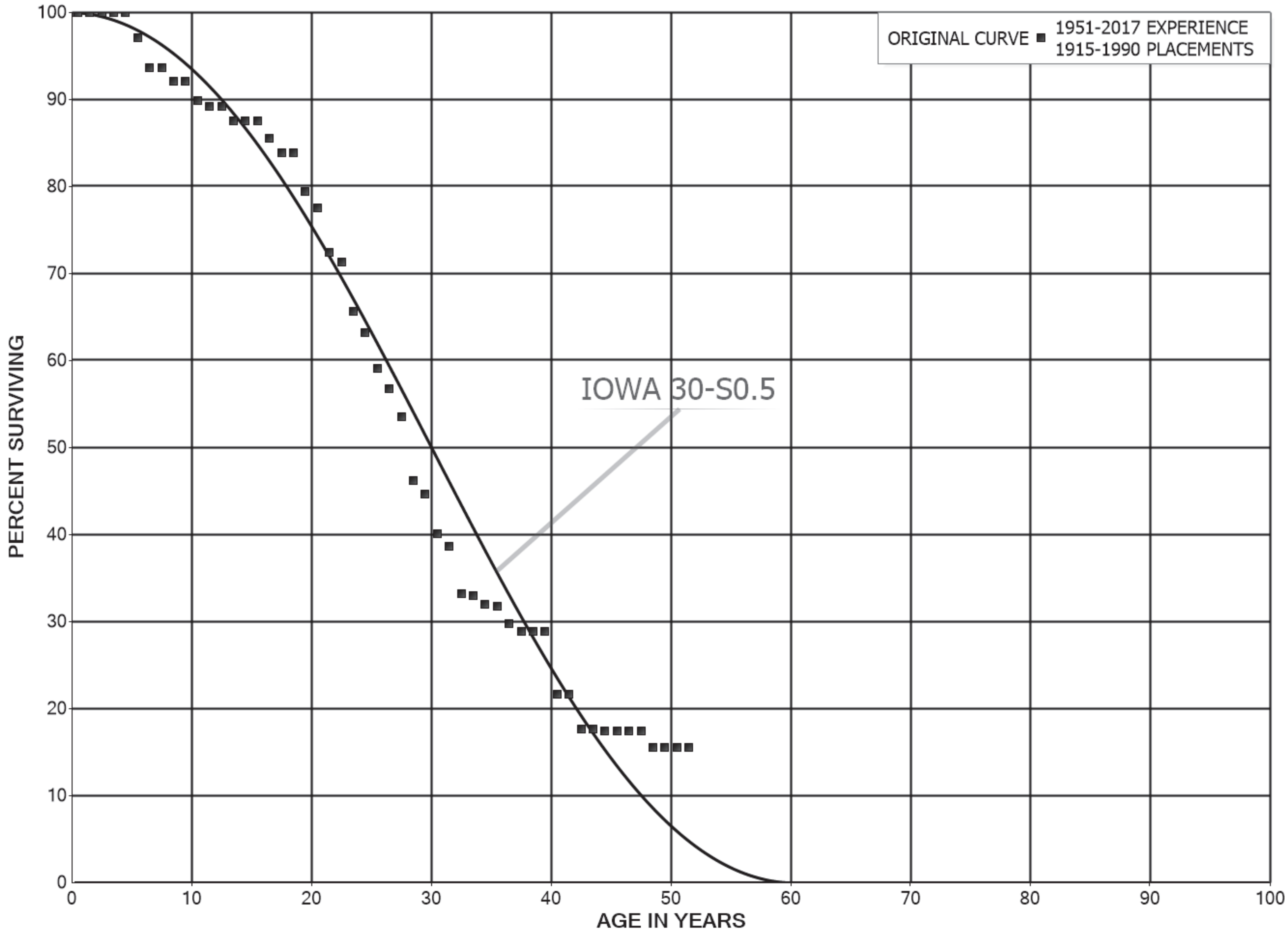
ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	324		0.0000	1.0000	7.27
80.5	324		0.0000	1.0000	7.27
81.5	324		0.0000	1.0000	7.27
82.5	204		0.0000	1.0000	7.27
83.5	204		0.0000	1.0000	7.27
84.5	204		0.0000	1.0000	7.27
85.5	204		0.0000	1.0000	7.27
86.5	204		0.0000	1.0000	7.27
87.5					7.27

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 335 DRILLING AND CLEANING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 335 DRILLING AND CLEANING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1915-1990 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	188,460		0.0000	1.0000	100.00
0.5	175,328		0.0000	1.0000	100.00
1.5	181,181		0.0000	1.0000	100.00
2.5	205,120		0.0000	1.0000	100.00
3.5	227,373		0.0000	1.0000	100.00
4.5	161,797	4,806	0.0297	0.9703	100.00
5.5	161,642	5,635	0.0349	0.9651	97.03
6.5	164,399		0.0000	1.0000	93.65
7.5	165,996	2,747	0.0166	0.9834	93.65
8.5	179,096		0.0000	1.0000	92.10
9.5	184,703	4,472	0.0242	0.9758	92.10
10.5	192,576	1,581	0.0082	0.9918	89.87
11.5	190,730		0.0000	1.0000	89.13
12.5	191,771	3,443	0.0180	0.9820	89.13
13.5	195,306		0.0000	1.0000	87.53
14.5	189,605		0.0000	1.0000	87.53
15.5	194,891	4,513	0.0232	0.9768	87.53
16.5	200,655	3,867	0.0193	0.9807	85.50
17.5	198,328		0.0000	1.0000	83.85
18.5	196,907	10,517	0.0534	0.9466	83.85
19.5	192,486	4,410	0.0229	0.9771	79.38
20.5	195,439	13,099	0.0670	0.9330	77.56
21.5	185,866	2,644	0.0142	0.9858	72.36
22.5	184,374	14,873	0.0807	0.9193	71.33
23.5	171,548	6,346	0.0370	0.9630	65.58
24.5	167,708	10,816	0.0645	0.9355	63.15
25.5	162,968	6,639	0.0407	0.9593	59.08
26.5	156,329	8,695	0.0556	0.9444	56.67
27.5	146,595	20,126	0.1373	0.8627	53.52
28.5	126,833	4,238	0.0334	0.9666	46.17
29.5	122,595	12,485	0.1018	0.8982	44.63
30.5	107,237	3,822	0.0356	0.9644	40.08
31.5	103,415	14,619	0.1414	0.8586	38.65
32.5	88,796	771	0.0087	0.9913	33.19
33.5	88,025	2,691	0.0306	0.9694	32.90
34.5	85,334	364	0.0043	0.9957	31.90
35.5	85,470	5,595	0.0655	0.9345	31.76
36.5	79,875	2,318	0.0290	0.9710	29.68
37.5	73,862		0.0000	1.0000	28.82
38.5	73,862		0.0000	1.0000	28.82

UGI UTILITIES, INC. - GAS DIVISION

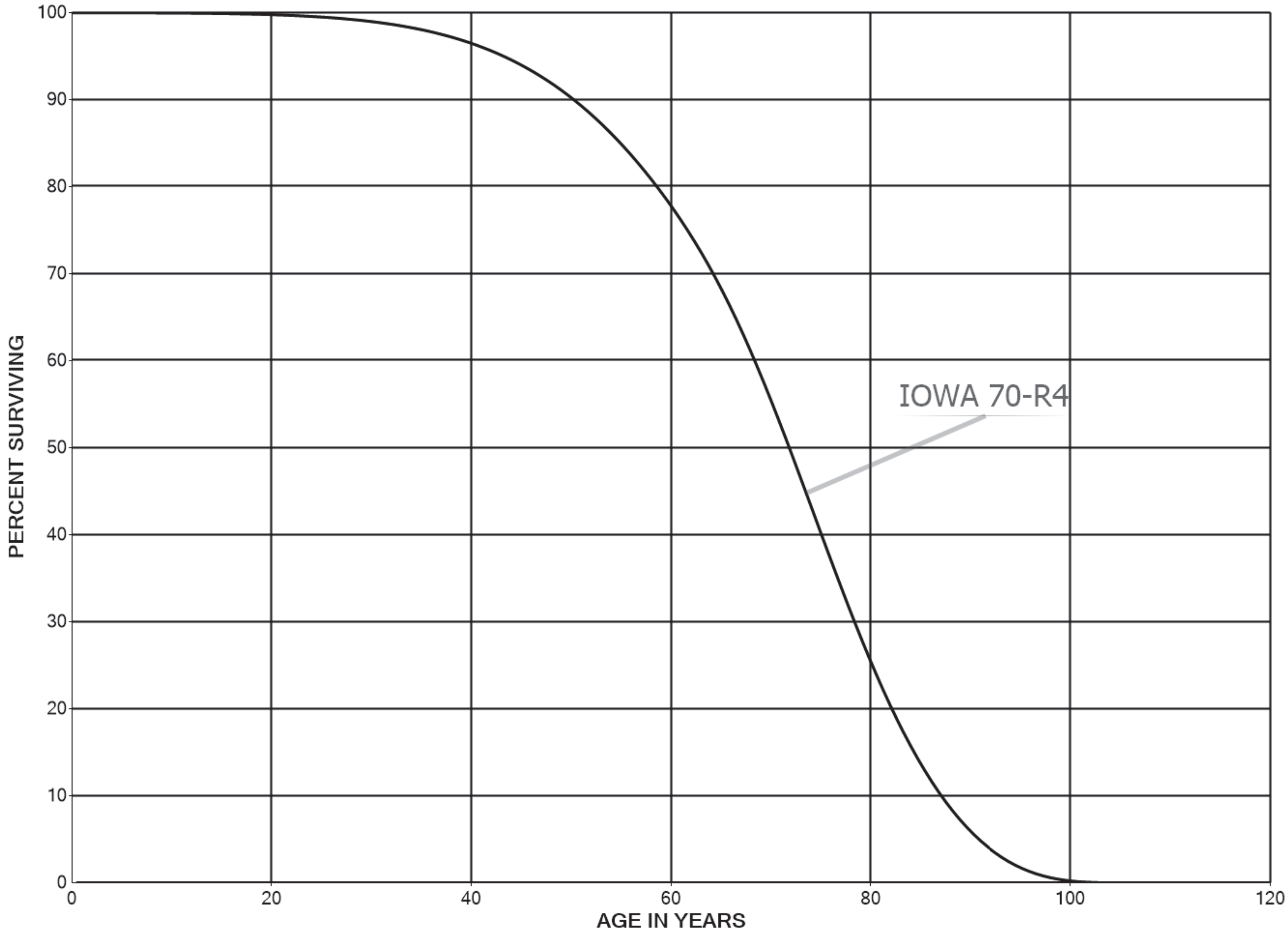
ACCOUNT 335 DRILLING AND CLEANING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

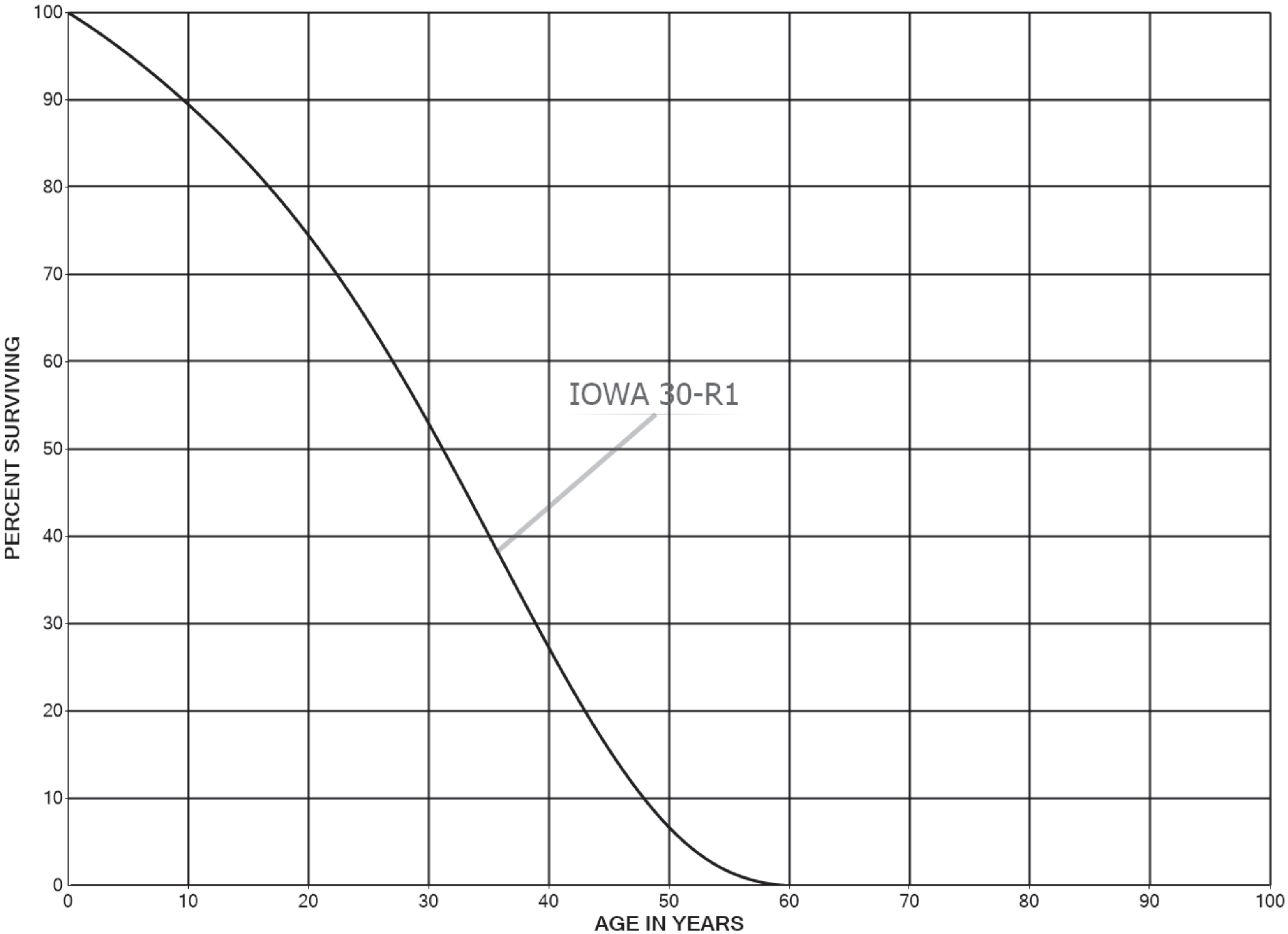
PLACEMENT BAND 1915-1990 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	73,862	18,344	0.2484	0.7516	28.82
40.5	55,518	175	0.0032	0.9968	21.66
41.5	55,343	10,117	0.1828	0.8172	21.59
42.5	45,227		0.0000	1.0000	17.65
43.5	45,227	536	0.0118	0.9882	17.65
44.5	44,691		0.0000	1.0000	17.44
45.5	44,691		0.0000	1.0000	17.44
46.5	39,539		0.0000	1.0000	17.44
47.5	39,539	4,389	0.1110	0.8890	17.44
48.5	35,150		0.0000	1.0000	15.50
49.5	35,150	102	0.0029	0.9971	15.50
50.5	16,036		0.0000	1.0000	15.46
51.5	11,948		0.0000	1.0000	15.46
52.5	11,948		0.0000	1.0000	15.46
53.5	11,948		0.0000	1.0000	15.46
54.5	11,948		0.0000	1.0000	15.46
55.5	11,948		0.0000	1.0000	15.46
56.5	11,948		0.0000	1.0000	15.46
57.5	11,948		0.0000	1.0000	15.46
58.5	11,948		0.0000	1.0000	15.46
59.5	11,948		0.0000	1.0000	15.46
60.5	11,948		0.0000	1.0000	15.46
61.5	11,948		0.0000	1.0000	15.46
62.5					15.46

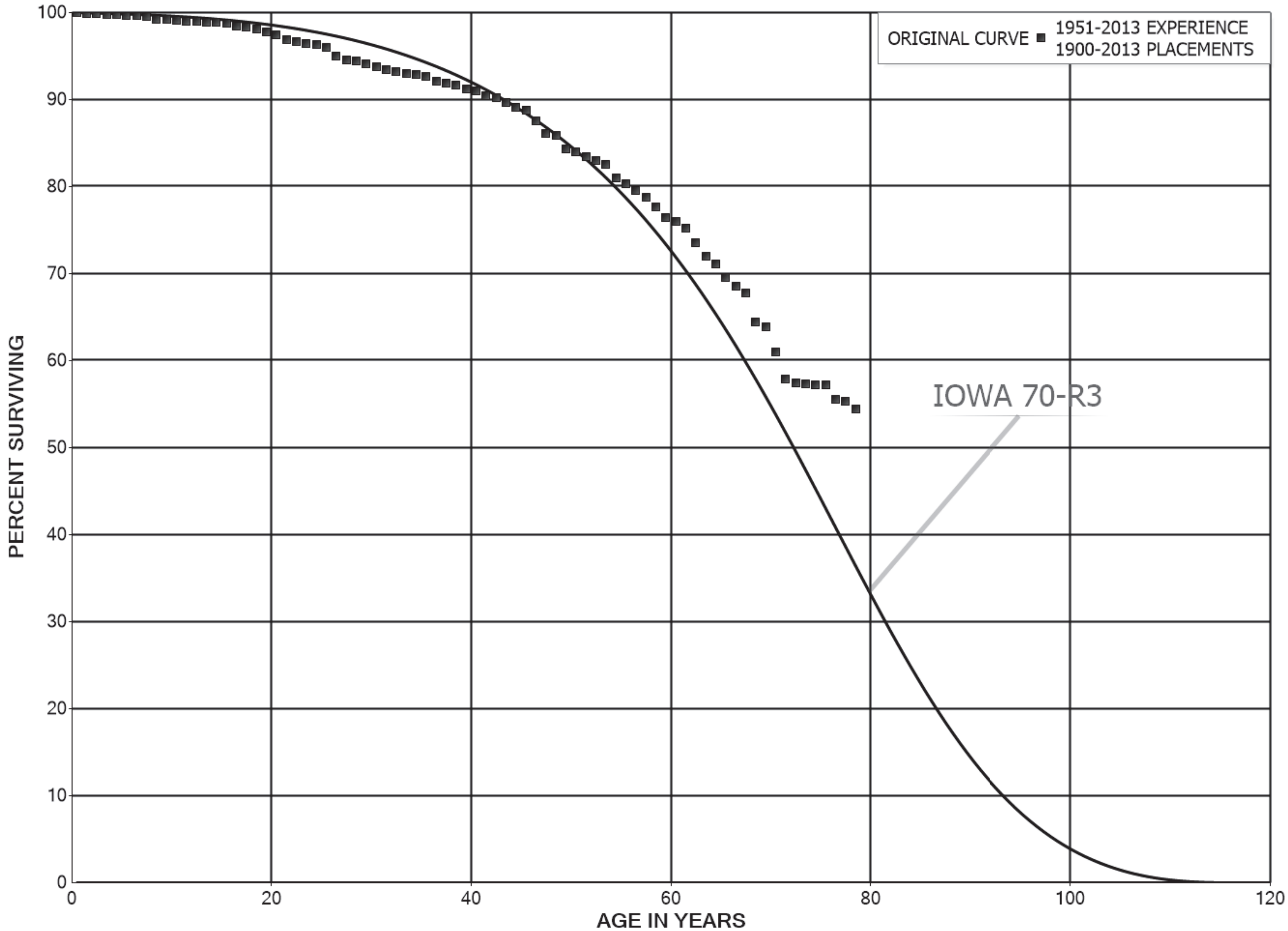
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 365.2 RIGHTS-OF-WAY
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 366 STRUCTURES AND IMPROVEMENTS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 367 MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	43,848,059	17,230	0.0004	0.9996	100.00
0.5	41,609,347	38,133	0.0009	0.9991	99.96
1.5	41,611,866	29,348	0.0007	0.9993	99.87
2.5	41,673,334	18,241	0.0004	0.9996	99.80
3.5	41,174,837	20,022	0.0005	0.9995	99.75
4.5	41,189,501	25,728	0.0006	0.9994	99.71
5.5	41,063,454	16,986	0.0004	0.9996	99.64
6.5	40,577,221	30,014	0.0007	0.9993	99.60
7.5	40,421,363	126,599	0.0031	0.9969	99.53
8.5	40,041,101	23,786	0.0006	0.9994	99.22
9.5	39,705,816	24,263	0.0006	0.9994	99.16
10.5	39,201,118	34,935	0.0009	0.9991	99.10
11.5	36,950,236	28,922	0.0008	0.9992	99.01
12.5	36,022,691	16,407	0.0005	0.9995	98.93
13.5	33,927,164	32,725	0.0010	0.9990	98.89
14.5	32,808,777	31,843	0.0010	0.9990	98.79
15.5	31,109,299	84,454	0.0027	0.9973	98.70
16.5	29,057,486	46,919	0.0016	0.9984	98.43
17.5	28,199,562	54,606	0.0019	0.9981	98.27
18.5	28,003,135	106,788	0.0038	0.9962	98.08
19.5	26,923,386	92,763	0.0034	0.9966	97.70
20.5	25,680,185	132,147	0.0051	0.9949	97.37
21.5	24,463,028	62,913	0.0026	0.9974	96.87
22.5	21,920,825	48,600	0.0022	0.9978	96.62
23.5	19,290,030	33,878	0.0018	0.9982	96.40
24.5	19,150,099	63,524	0.0033	0.9967	96.23
25.5	18,601,973	191,547	0.0103	0.9897	95.92
26.5	18,088,396	73,112	0.0040	0.9960	94.93
27.5	17,281,749	31,448	0.0018	0.9982	94.54
28.5	16,796,709	48,550	0.0029	0.9971	94.37
29.5	15,998,391	65,299	0.0041	0.9959	94.10
30.5	15,389,449	60,057	0.0039	0.9961	93.71
31.5	15,014,695	34,606	0.0023	0.9977	93.35
32.5	14,691,248	30,637	0.0021	0.9979	93.13
33.5	14,416,864	21,980	0.0015	0.9985	92.94
34.5	13,891,909	21,216	0.0015	0.9985	92.80
35.5	13,395,874	83,249	0.0062	0.9938	92.66
36.5	13,176,595	32,916	0.0025	0.9975	92.08
37.5	12,983,410	40,977	0.0032	0.9968	91.85
38.5	12,687,200	48,919	0.0039	0.9961	91.56

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

ORIGINAL LIFE TABLE, CONT.

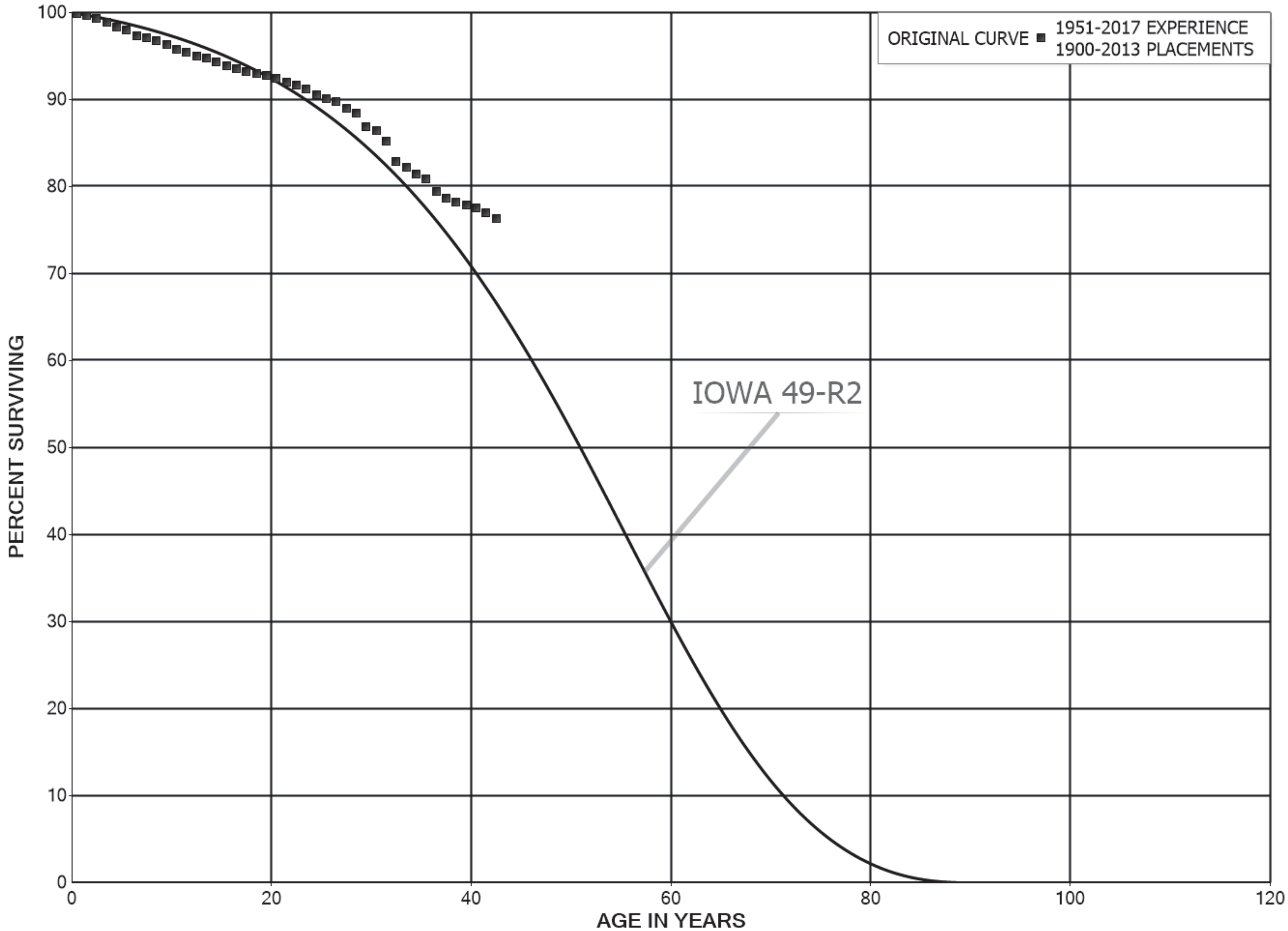
PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,170,805	27,669	0.0023	0.9977	91.21
40.5	11,782,750	84,272	0.0072	0.9928	91.00
41.5	10,731,783	15,542	0.0014	0.9986	90.35
42.5	10,254,844	69,088	0.0067	0.9933	90.22
43.5	9,310,207	55,876	0.0060	0.9940	89.61
44.5	8,618,031	38,976	0.0045	0.9955	89.07
45.5	8,208,516	106,439	0.0130	0.9870	88.67
46.5	7,946,490	136,085	0.0171	0.9829	87.52
47.5	7,183,761	12,335	0.0017	0.9983	86.02
48.5	6,658,456	125,000	0.0188	0.9812	85.87
49.5	6,253,758	21,608	0.0035	0.9965	84.26
50.5	6,264,805	40,613	0.0065	0.9935	83.97
51.5	6,033,474	37,752	0.0063	0.9937	83.43
52.5	5,947,816	29,238	0.0049	0.9951	82.90
53.5	5,242,208	98,818	0.0189	0.9811	82.50
54.5	4,521,764	37,702	0.0083	0.9917	80.94
55.5	4,183,809	41,394	0.0099	0.9901	80.27
56.5	3,831,232	37,947	0.0099	0.9901	79.47
57.5	2,319,503	32,611	0.0141	0.9859	78.69
58.5	2,204,928	32,728	0.0148	0.9852	77.58
59.5	1,373,952	8,748	0.0064	0.9936	76.43
60.5	1,165,182	11,119	0.0095	0.9905	75.94
61.5	1,064,257	23,546	0.0221	0.9779	75.22
62.5	837,153	18,091	0.0216	0.9784	73.55
63.5	850,626	10,162	0.0119	0.9881	71.96
64.5	812,265	18,038	0.0222	0.9778	71.10
65.5	695,390	10,166	0.0146	0.9854	69.52
66.5	646,441	7,461	0.0115	0.9885	68.51
67.5	635,293	31,231	0.0492	0.9508	67.72
68.5	578,311	5,353	0.0093	0.9907	64.39
69.5	572,148	25,005	0.0437	0.9563	63.79
70.5	541,305	28,306	0.0523	0.9477	61.00
71.5	511,783	4,044	0.0079	0.9921	57.81
72.5	496,105	695	0.0014	0.9986	57.36
73.5	484,045	413	0.0009	0.9991	57.28
74.5	482,834	570	0.0012	0.9988	57.23
75.5	479,467	13,539	0.0282	0.9718	57.16
76.5	463,539	2,024	0.0044	0.9956	55.55
77.5	444,893	7,658	0.0172	0.9828	55.30
78.5	432,933	7,166	0.0166	0.9834	54.35

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2013

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	414,334	277	0.0007	0.9993	53.45
80.5	409,160	1,689	0.0041	0.9959	53.42
81.5	284,117	32,605	0.1148	0.8852	53.20
82.5	251,215	1,179	0.0047	0.9953	47.09
83.5	247,514	1,604	0.0065	0.9935	46.87
84.5	218,380		0.0000	1.0000	46.57
85.5	218,200	8,283	0.0380	0.9620	46.57
86.5	207,746	1,815	0.0087	0.9913	44.80
87.5	159,466	186	0.0012	0.9988	44.41
88.5	157,923	867	0.0055	0.9945	44.36
89.5	157,056	1,108	0.0071	0.9929	44.11
90.5	155,947	3,306	0.0212	0.9788	43.80
91.5	152,606	2,135	0.0140	0.9860	42.87
92.5	150,470	3,562	0.0237	0.9763	42.27
93.5	146,908		0.0000	1.0000	41.27
94.5	146,908	764	0.0052	0.9948	41.27
95.5	146,144		0.0000	1.0000	41.06
96.5	146,144	189	0.0013	0.9987	41.06
97.5	145,955		0.0000	1.0000	41.00
98.5	145,878		0.0000	1.0000	41.00
99.5	145,878		0.0000	1.0000	41.00
100.5	144,140		0.0000	1.0000	41.00
101.5	144,140		0.0000	1.0000	41.00
102.5	144,140		0.0000	1.0000	41.00
103.5	143,390		0.0000	1.0000	41.00
104.5	143,390		0.0000	1.0000	41.00
105.5	143,390		0.0000	1.0000	41.00
106.5	134,660	1,763	0.0131	0.9869	41.00
107.5	130,476		0.0000	1.0000	40.47
108.5	130,476		0.0000	1.0000	40.47
109.5	128,512		0.0000	1.0000	40.47
110.5	95,314		0.0000	1.0000	40.47
111.5	71,234		0.0000	1.0000	40.47
112.5	71,234		0.0000	1.0000	40.47
113.5					40.47

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,695,693	7,521	0.0011	0.9989	100.00
0.5	6,728,282	20,997	0.0031	0.9969	99.89
1.5	6,710,982	21,499	0.0032	0.9968	99.58
2.5	6,705,164	32,167	0.0048	0.9952	99.26
3.5	6,697,253	30,678	0.0046	0.9954	98.78
4.5	6,696,172	25,064	0.0037	0.9963	98.33
5.5	6,679,077	42,637	0.0064	0.9936	97.96
6.5	6,643,178	18,226	0.0027	0.9973	97.33
7.5	6,622,744	22,925	0.0035	0.9965	97.07
8.5	6,663,450	29,366	0.0044	0.9956	96.73
9.5	6,385,813	41,226	0.0065	0.9935	96.31
10.5	6,308,924	21,963	0.0035	0.9965	95.68
11.5	6,205,987	28,315	0.0046	0.9954	95.35
12.5	6,102,975	13,048	0.0021	0.9979	94.92
13.5	6,022,175	30,191	0.0050	0.9950	94.71
14.5	5,700,273	23,732	0.0042	0.9958	94.24
15.5	5,523,282	19,343	0.0035	0.9965	93.85
16.5	5,022,708	19,038	0.0038	0.9962	93.52
17.5	4,828,969	10,916	0.0023	0.9977	93.16
18.5	4,797,301	9,326	0.0019	0.9981	92.95
19.5	4,232,870	16,589	0.0039	0.9961	92.77
20.5	3,493,802	16,403	0.0047	0.9953	92.41
21.5	3,252,363	13,800	0.0042	0.9958	91.97
22.5	3,124,010	15,137	0.0048	0.9952	91.58
23.5	2,765,377	18,932	0.0068	0.9932	91.14
24.5	2,584,735	13,268	0.0051	0.9949	90.52
25.5	2,301,630	8,705	0.0038	0.9962	90.05
26.5	2,145,262	17,111	0.0080	0.9920	89.71
27.5	1,829,337	13,316	0.0073	0.9927	88.99
28.5	1,773,318	29,698	0.0167	0.9833	88.35
29.5	1,332,318	7,874	0.0059	0.9941	86.87
30.5	1,270,087	17,542	0.0138	0.9862	86.35
31.5	1,169,153	31,415	0.0269	0.9731	85.16
32.5	1,051,208	8,674	0.0083	0.9917	82.87
33.5	991,638	8,968	0.0090	0.9910	82.19
34.5	957,945	7,653	0.0080	0.9920	81.45
35.5	793,965	14,200	0.0179	0.9821	80.80
36.5	696,529	6,679	0.0096	0.9904	79.35
37.5	677,107	3,516	0.0052	0.9948	78.59
38.5	632,534	2,848	0.0045	0.9955	78.18

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	607,864	2,821	0.0046	0.9954	77.83
40.5	590,798	3,562	0.0060	0.9940	77.47
41.5	448,065	4,434	0.0099	0.9901	77.00
42.5	414,054	1,433	0.0035	0.9965	76.24
43.5	394,898	1,066	0.0027	0.9973	75.98
44.5	378,183	1,003	0.0027	0.9973	75.77
45.5	350,079	510	0.0015	0.9985	75.57
46.5	319,280	2,640	0.0083	0.9917	75.46
47.5	301,686	1,398	0.0046	0.9954	74.84
48.5	268,860	770	0.0029	0.9971	74.49
49.5	250,034	1,844	0.0074	0.9926	74.28
50.5	229,844	1,321	0.0057	0.9943	73.73
51.5	185,683	724	0.0039	0.9961	73.30
52.5	167,467	3,050	0.0182	0.9818	73.02
53.5	145,822	798	0.0055	0.9945	71.69
54.5	139,886	614	0.0044	0.9956	71.30
55.5	126,241	73	0.0006	0.9994	70.98
56.5	120,746	517	0.0043	0.9957	70.94
57.5	95,893	875	0.0091	0.9909	70.64
58.5	85,192	183	0.0021	0.9979	69.99
59.5	78,565	115	0.0015	0.9985	69.84
60.5	64,876	165	0.0025	0.9975	69.74
61.5	24,958		0.0000	1.0000	69.56
62.5	17,416	41	0.0023	0.9977	69.56
63.5	8,955		0.0000	1.0000	69.40
64.5	3,011		0.0000	1.0000	69.40
65.5	2,992	348	0.1162	0.8838	69.40
66.5	2,644		0.0000	1.0000	61.34
67.5	2,637	276	0.1046	0.8954	61.34
68.5	2,361	67	0.0284	0.9716	54.92
69.5	2,205	140	0.0635	0.9365	53.36
70.5	1,787	65	0.0363	0.9637	49.97
71.5	1,559	107	0.0685	0.9315	48.16
72.5	1,278		0.0000	1.0000	44.86
73.5	1,194		0.0000	1.0000	44.86
74.5	986	47	0.0476	0.9524	44.86
75.5	824	43	0.0522	0.9478	42.73
76.5	781		0.0000	1.0000	40.50
77.5	592		0.0000	1.0000	40.50
78.5	392		0.0000	1.0000	40.50

UGI UTILITIES, INC. - GAS DIVISION

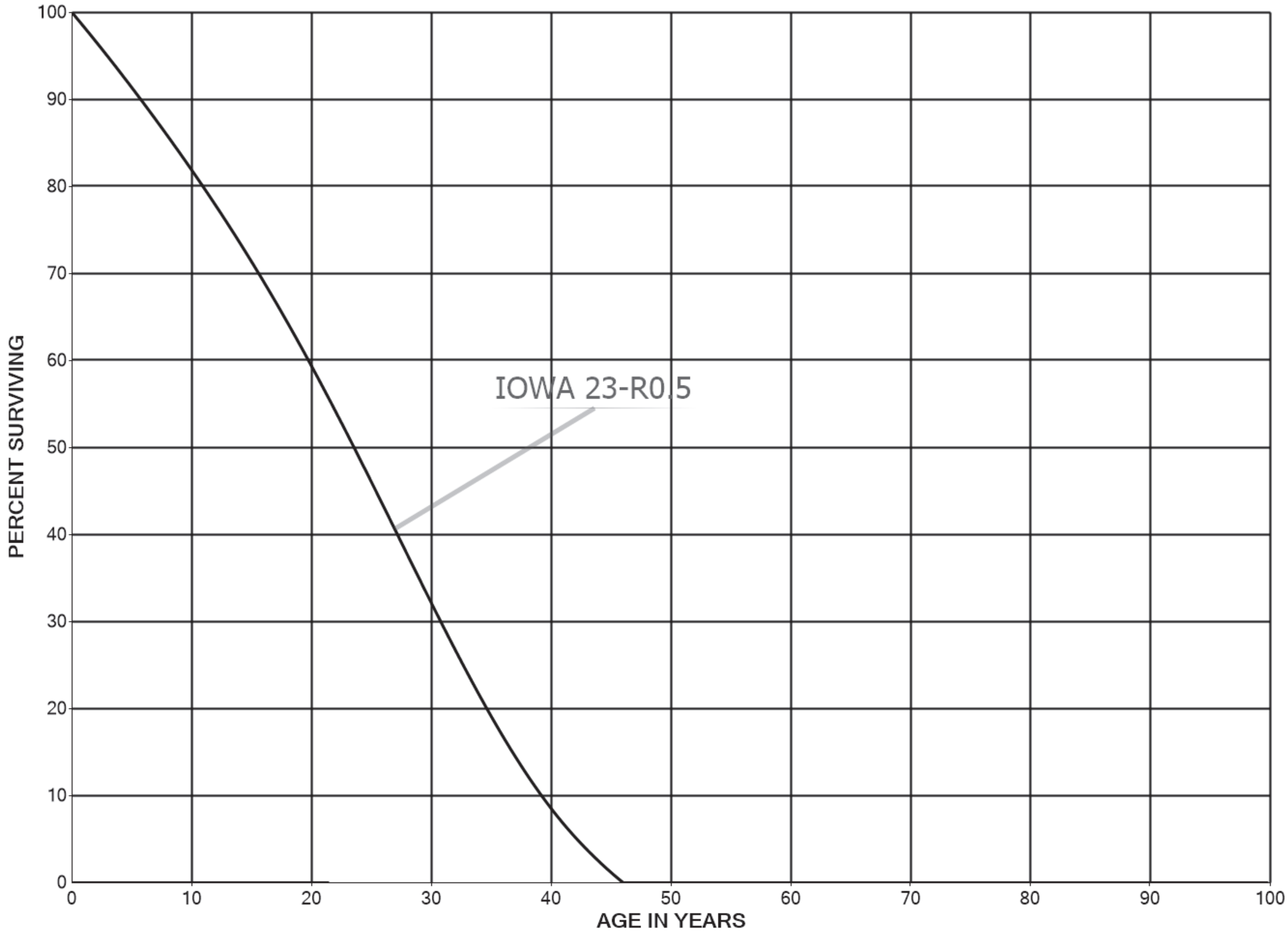
ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

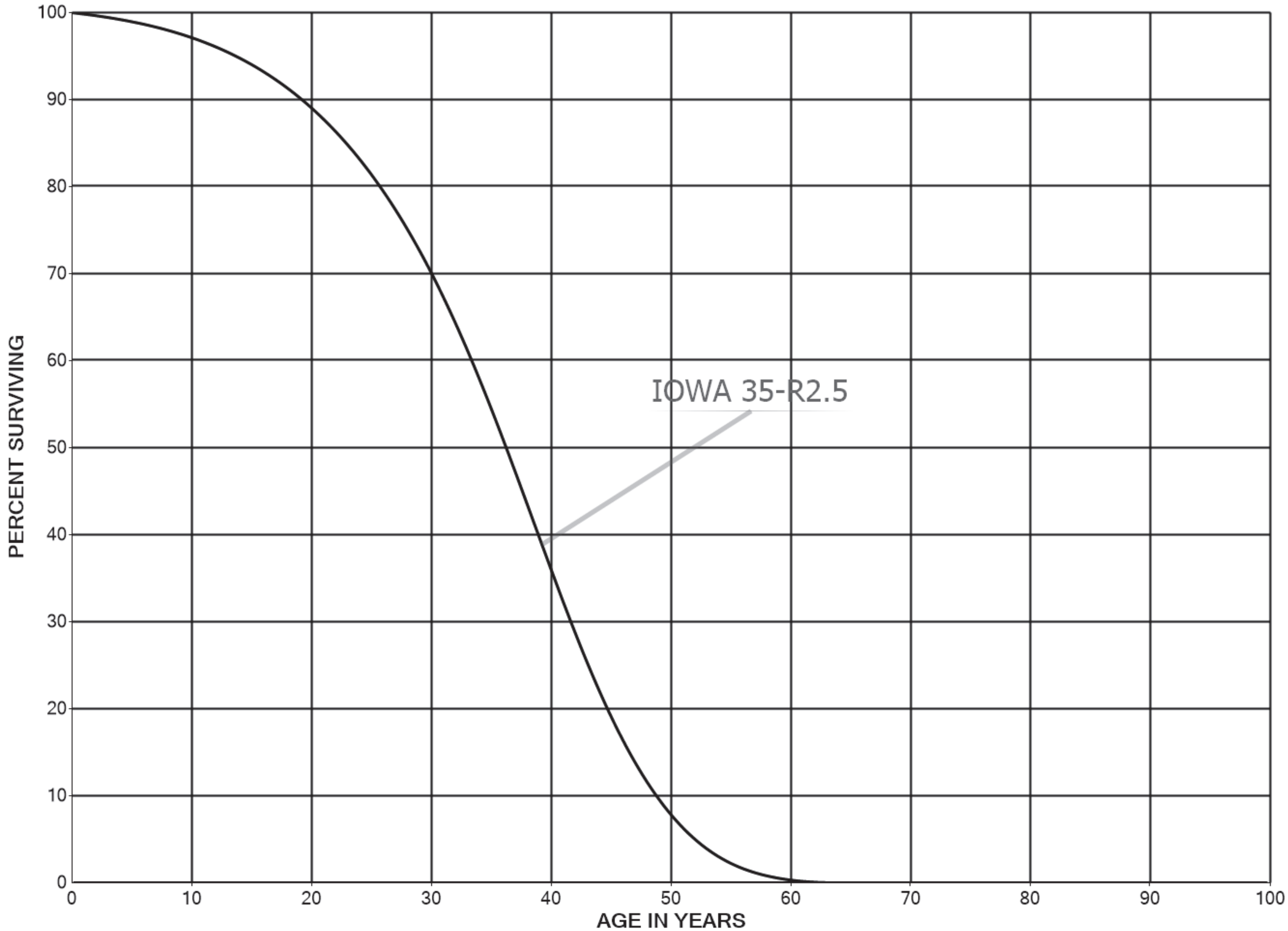
PLACEMENT BAND 1900-2013 EXPERIENCE BAND 1951-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	262		0.0000	1.0000	40.50
80.5	198	89	0.4508	0.5492	40.50
81.5	109		0.0000	1.0000	22.24
82.5	108		0.0000	1.0000	22.24
83.5	108		0.0000	1.0000	22.24
84.5	108	65	0.5977	0.4023	22.24
85.5	43		0.0000	1.0000	8.95
86.5	43		0.0000	1.0000	8.95
87.5	43		0.0000	1.0000	8.95
88.5	43		0.0000	1.0000	8.95
89.5	43		0.0000	1.0000	8.95
90.5					8.95
91.5					
92.5					
93.5					
94.5					
95.5	24,615		0.0000		
96.5	24,615		0.0000		
97.5	24,615		0.0000		
98.5	24,615		0.0000		
99.5	24,615		0.0000		
100.5	24,615		0.0000		
101.5	24,615		0.0000		
102.5					

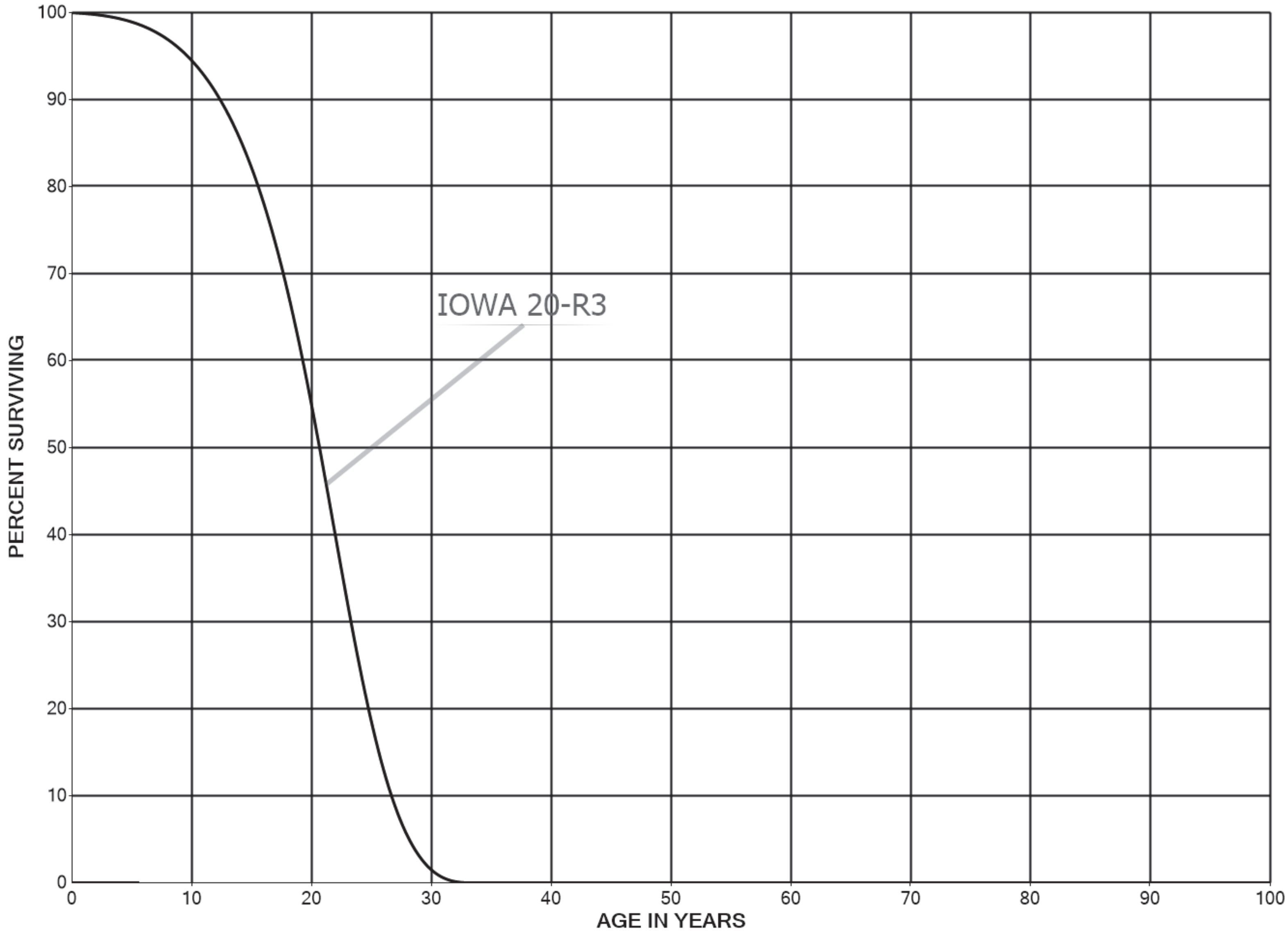
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 370 COMMUNICATION EQUIPMENT
SMOOTH SURVIVOR CURVE



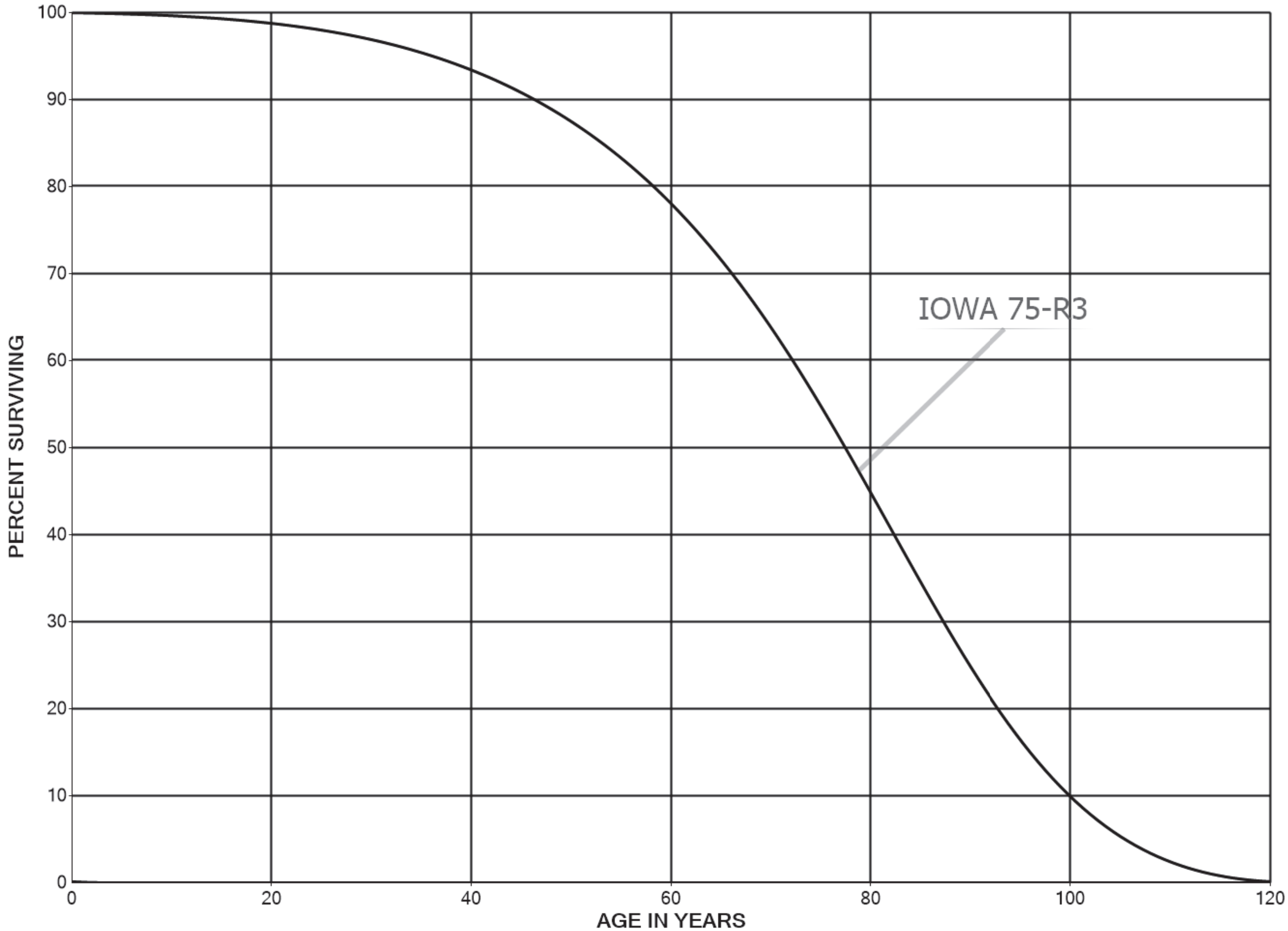
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 371 OTHER EQUIPMENT
SMOOTH SURVIVOR CURVE



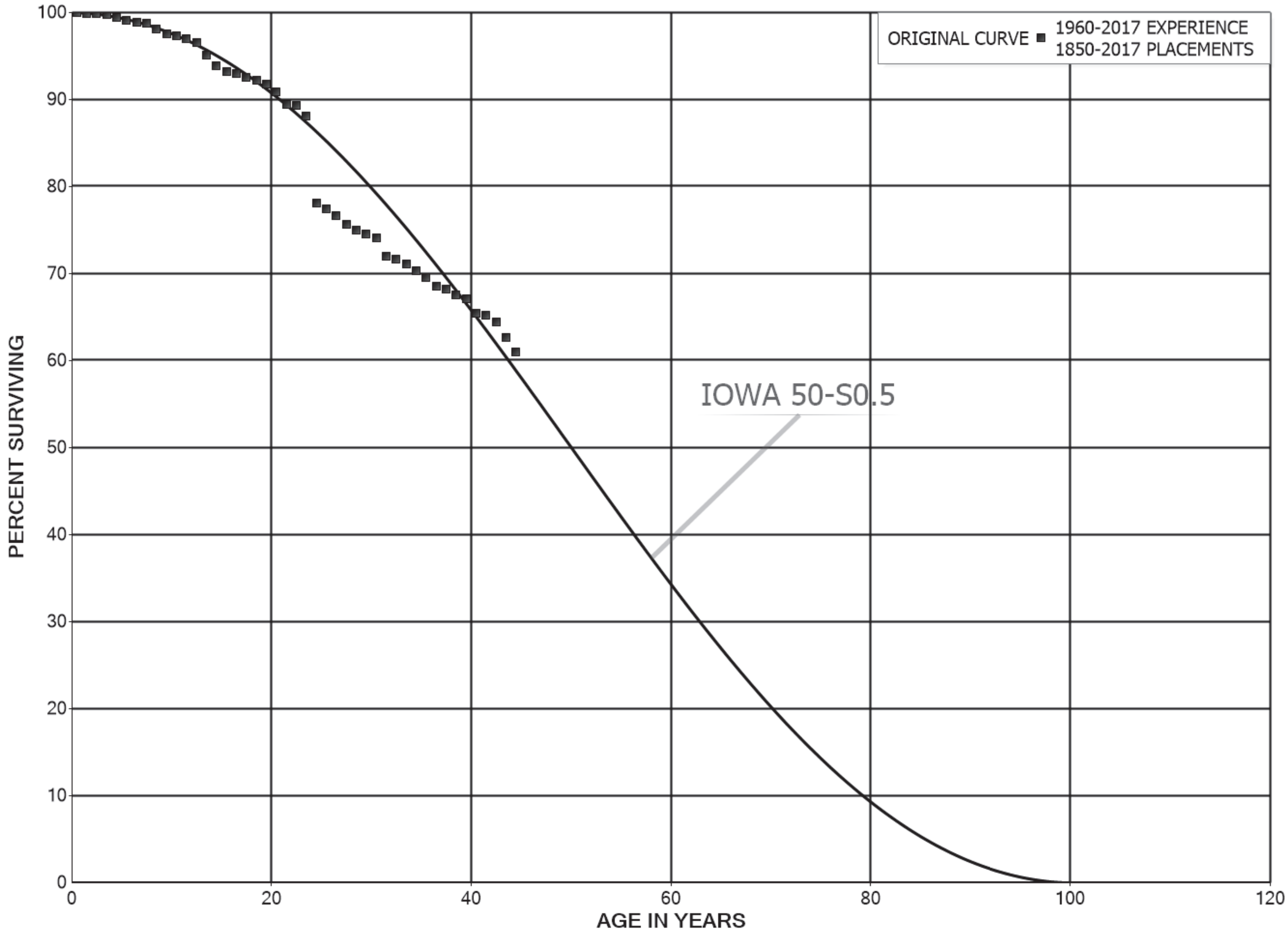
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 371.1 TESTING EQUIPMENT
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 374.2 RIGHTS-OF-WAY
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 375 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1850-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,088,205	3,318	0.0008	0.9992	100.00
0.5	4,074,097	3,737	0.0009	0.9991	99.92
1.5	4,027,591		0.0000	1.0000	99.83
2.5	4,101,745	3,306	0.0008	0.9992	99.83
3.5	2,948,679	11,465	0.0039	0.9961	99.75
4.5	2,843,742	9,228	0.0032	0.9968	99.36
5.5	2,724,950	5,692	0.0021	0.9979	99.04
6.5	2,767,656	2,524	0.0009	0.9991	98.83
7.5	3,036,517	20,233	0.0067	0.9933	98.74
8.5	2,882,507	17,351	0.0060	0.9940	98.08
9.5	3,141,870	7,063	0.0022	0.9978	97.49
10.5	3,016,383	8,495	0.0028	0.9972	97.27
11.5	2,877,087	14,072	0.0049	0.9951	97.00
12.5	2,817,677	42,651	0.0151	0.9849	96.52
13.5	2,824,085	36,006	0.0127	0.9873	95.06
14.5	2,782,280	20,955	0.0075	0.9925	93.85
15.5	2,691,914	4,693	0.0017	0.9983	93.14
16.5	2,633,955	12,121	0.0046	0.9954	92.98
17.5	2,603,357	11,151	0.0043	0.9957	92.55
18.5	2,545,821	12,795	0.0050	0.9950	92.16
19.5	2,421,684	22,821	0.0094	0.9906	91.69
20.5	2,303,853	35,302	0.0153	0.9847	90.83
21.5	2,173,833	3,450	0.0016	0.9984	89.44
22.5	2,159,729	30,701	0.0142	0.9858	89.30
23.5	2,103,731	238,693	0.1135	0.8865	88.03
24.5	1,839,272	16,079	0.0087	0.9913	78.04
25.5	1,843,817	18,322	0.0099	0.9901	77.36
26.5	1,846,052	23,063	0.0125	0.9875	76.59
27.5	1,820,458	16,209	0.0089	0.9911	75.63
28.5	1,823,527	9,988	0.0055	0.9945	74.96
29.5	1,887,565	11,358	0.0060	0.9940	74.55
30.5	1,833,591	52,840	0.0288	0.9712	74.10
31.5	1,778,848	8,889	0.0050	0.9950	71.96
32.5	1,710,425	12,311	0.0072	0.9928	71.60
33.5	1,611,273	19,081	0.0118	0.9882	71.09
34.5	1,638,576	17,605	0.0107	0.9893	70.25
35.5	1,679,367	23,412	0.0139	0.9861	69.49
36.5	1,661,586	9,483	0.0057	0.9943	68.52
37.5	1,661,613	15,185	0.0091	0.9909	68.13
38.5	1,641,242	9,877	0.0060	0.9940	67.51

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1850-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,644,589	41,526	0.0253	0.9747	67.10
40.5	1,587,513	6,420	0.0040	0.9960	65.41
41.5	1,587,626	19,157	0.0121	0.9879	65.14
42.5	1,469,018	40,431	0.0275	0.9725	64.36
43.5	1,422,207	35,918	0.0253	0.9747	62.59
44.5	1,352,016	6,436	0.0048	0.9952	61.01
45.5	1,346,932	10,423	0.0077	0.9923	60.72
46.5	1,349,424	3,036	0.0023	0.9977	60.25
47.5	1,336,965	4,542	0.0034	0.9966	60.11
48.5	1,321,533	8,858	0.0067	0.9933	59.91
49.5	1,400,527	61,229	0.0437	0.9563	59.50
50.5	1,604,149	24,078	0.0150	0.9850	56.90
51.5	1,692,542	19,791	0.0117	0.9883	56.05
52.5	1,652,777	3,921	0.0024	0.9976	55.39
53.5	1,604,032	127	0.0001	0.9999	55.26
54.5	1,545,644	3,895	0.0025	0.9975	55.26
55.5	1,467,850	20,458	0.0139	0.9861	55.12
56.5	1,384,380	5,678	0.0041	0.9959	54.35
57.5	1,337,364	10,704	0.0080	0.9920	54.13
58.5	1,287,991	9,963	0.0077	0.9923	53.69
59.5	1,262,070	3,498	0.0028	0.9972	53.28
60.5	1,171,460	10,069	0.0086	0.9914	53.13
61.5	1,128,212	9,665	0.0086	0.9914	52.67
62.5	1,096,070	6,422	0.0059	0.9941	52.22
63.5	1,015,629	25,312	0.0249	0.9751	51.92
64.5	873,662	6,254	0.0072	0.9928	50.62
65.5	813,372	8,035	0.0099	0.9901	50.26
66.5	690,562	9,895	0.0143	0.9857	49.76
67.5	356,124	10,621	0.0298	0.9702	49.05
68.5	188,961	28,813	0.1525	0.8475	47.59
69.5	142,917	16,679	0.1167	0.8833	40.33
70.5	130,193	3,267	0.0251	0.9749	35.63
71.5	104,335	498	0.0048	0.9952	34.73
72.5	95,790	18	0.0002	0.9998	34.57
73.5	107,755		0.0000	1.0000	34.56
74.5	103,302		0.0000	1.0000	34.56
75.5	106,578	162	0.0015	0.9985	34.56
76.5	148,045	168	0.0011	0.9989	34.51
77.5	148,450	210	0.0014	0.9986	34.47
78.5	147,299		0.0000	1.0000	34.42

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1850-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	167,641	2,347	0.0140	0.9860	34.42
80.5	161,079	249	0.0015	0.9985	33.94
81.5	161,933	425	0.0026	0.9974	33.88
82.5	161,508		0.0000	1.0000	33.80
83.5	166,202		0.0000	1.0000	33.80
84.5	162,005	256	0.0016	0.9984	33.80
85.5	162,795	860	0.0053	0.9947	33.74
86.5	178,293		0.0000	1.0000	33.56
87.5	176,610		0.0000	1.0000	33.56
88.5	175,130		0.0000	1.0000	33.56
89.5	174,066		0.0000	1.0000	33.56
90.5	145,253	882	0.0061	0.9939	33.56
91.5	141,373		0.0000	1.0000	33.36
92.5	116,958		0.0000	1.0000	33.36
93.5	67,378		0.0000	1.0000	33.36
94.5	66,667		0.0000	1.0000	33.36
95.5	62,168		0.0000	1.0000	33.36
96.5	44,760		0.0000	1.0000	33.36
97.5	42,227		0.0000	1.0000	33.36
98.5	41,235		0.0000	1.0000	33.36
99.5	36,491		0.0000	1.0000	33.36
100.5	31,236		0.0000	1.0000	33.36
101.5	29,685		0.0000	1.0000	33.36
102.5	29,683		0.0000	1.0000	33.36
103.5	37,372		0.0000	1.0000	33.36
104.5	36,372		0.0000	1.0000	33.36
105.5	38,917		0.0000	1.0000	33.36
106.5	39,412		0.0000	1.0000	33.36
107.5	30,174		0.0000	1.0000	33.36
108.5	29,111	9,167	0.3149	0.6851	33.36
109.5	19,775		0.0000	1.0000	22.85
110.5	19,775		0.0000	1.0000	22.85
111.5	20,500	67	0.0033	0.9967	22.85
112.5	19,112		0.0000	1.0000	22.78
113.5	18,338		0.0000	1.0000	22.78
114.5	18,338		0.0000	1.0000	22.78
115.5	13,732	975	0.0710	0.9290	22.78
116.5	12,322	418	0.0340	0.9660	21.16
117.5	11,780	2,117	0.1797	0.8203	20.44
118.5	9,155		0.0000	1.0000	16.77

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1850-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	8,996		0.0000	1.0000	16.77
120.5	8,817		0.0000	1.0000	16.77
121.5	8,817		0.0000	1.0000	16.77
122.5	6,256		0.0000	1.0000	16.77
123.5	6,256		0.0000	1.0000	16.77
124.5	6,256		0.0000	1.0000	16.77
125.5	6,256		0.0000	1.0000	16.77
126.5	5,556		0.0000	1.0000	16.77
127.5	5,556		0.0000	1.0000	16.77
128.5	1,363		0.0000	1.0000	16.77
129.5	1,363		0.0000	1.0000	16.77
130.5	1,363		0.0000	1.0000	16.77
131.5	1,363		0.0000	1.0000	16.77
132.5	1,436		0.0000	1.0000	16.77
133.5	1,436		0.0000	1.0000	16.77
134.5	1,436		0.0000	1.0000	16.77
135.5	1,436		0.0000	1.0000	16.77
136.5	1,436		0.0000	1.0000	16.77
137.5	1,436		0.0000	1.0000	16.77
138.5	1,436		0.0000	1.0000	16.77
139.5	1,436		0.0000	1.0000	16.77
140.5	1,436		0.0000	1.0000	16.77
141.5	1,436		0.0000	1.0000	16.77
142.5	1,436		0.0000	1.0000	16.77
143.5	1,436		0.0000	1.0000	16.77
144.5	1,436		0.0000	1.0000	16.77
145.5	1,436		0.0000	1.0000	16.77
146.5	1,436		0.0000	1.0000	16.77
147.5	1,436		0.0000	1.0000	16.77
148.5	1,436		0.0000	1.0000	16.77
149.5	1,363		0.0000	1.0000	16.77
150.5	2,795		0.0000	1.0000	16.77
151.5	2,811		0.0000	1.0000	16.77
152.5	2,811		0.0000	1.0000	16.77
153.5	2,811		0.0000	1.0000	16.77
154.5	2,811		0.0000	1.0000	16.77
155.5	2,795		0.0000	1.0000	16.77
156.5	2,795		0.0000	1.0000	16.77
157.5	2,795		0.0000	1.0000	16.77
158.5	2,795		0.0000	1.0000	16.77

UGI UTILITIES, INC. - GAS DIVISION

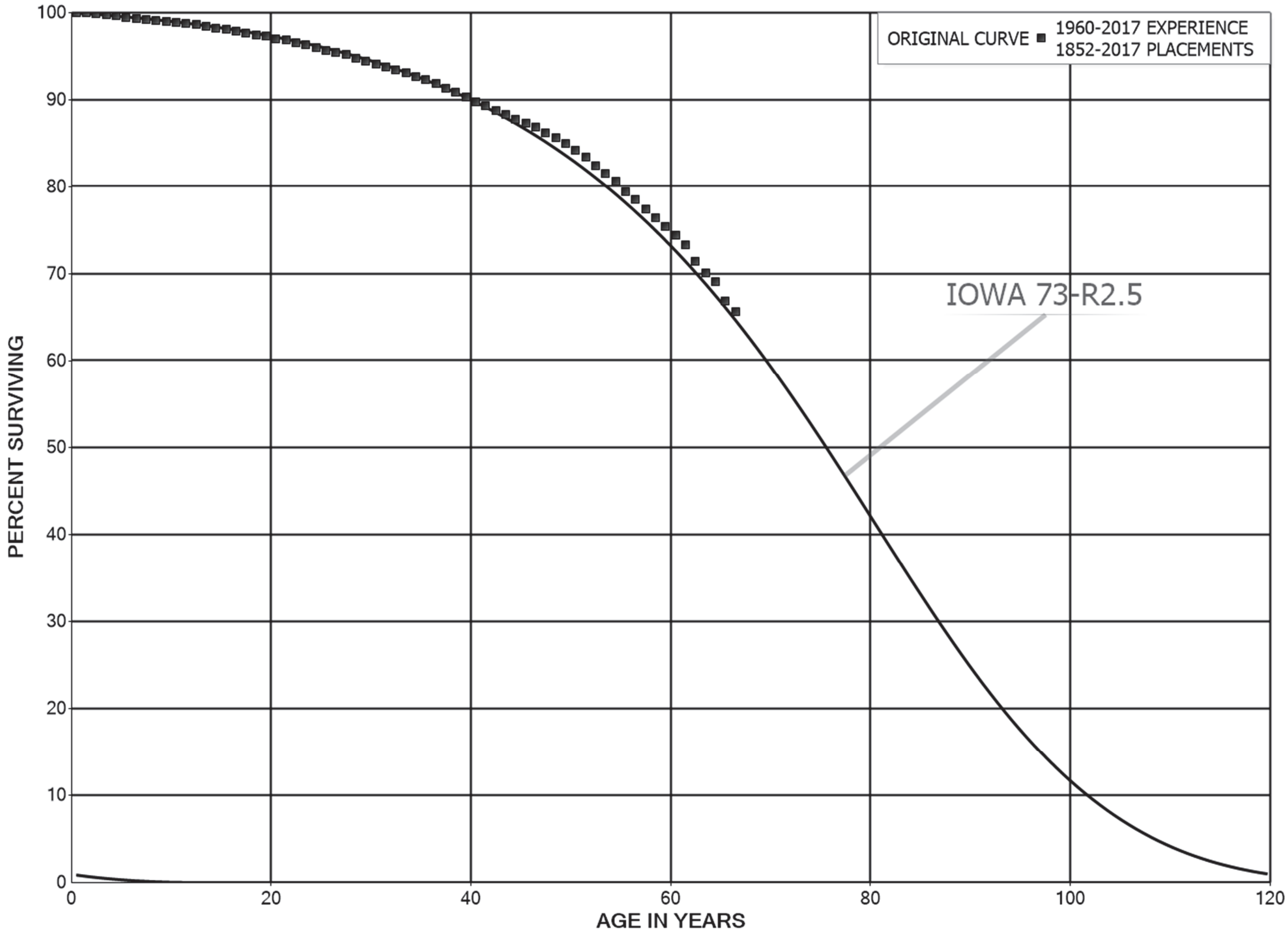
ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1850-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
159.5	2,795		0.0000	1.0000	16.77
160.5	2,795		0.0000	1.0000	16.77
161.5	2,795		0.0000	1.0000	16.77
162.5	2,795		0.0000	1.0000	16.77
163.5	2,795		0.0000	1.0000	16.77
164.5	2,795		0.0000	1.0000	16.77
165.5	2,795		0.0000	1.0000	16.77
166.5	2,795		0.0000	1.0000	16.77
167.5					16.77

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 376.1 MAINS - PRIMARILY STEEL
ORIGINAL AND SMOOTH SURVIVOR CURVES



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UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS – PRIMARILY STEEL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1852-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,376,022,388	79,180	0.0001	0.9999	100.00
0.5	1,315,634,329	1,162,640	0.0009	0.9991	99.99
1.5	1,196,595,817	1,042,984	0.0009	0.9991	99.91
2.5	1,112,566,819	1,220,301	0.0011	0.9989	99.82
3.5	1,044,976,776	1,022,437	0.0010	0.9990	99.71
4.5	996,420,079	1,669,633	0.0017	0.9983	99.61
5.5	954,388,147	1,094,543	0.0011	0.9989	99.44
6.5	920,850,782	1,160,697	0.0013	0.9987	99.33
7.5	894,226,017	1,271,638	0.0014	0.9986	99.21
8.5	866,277,582	742,488	0.0009	0.9991	99.06
9.5	841,215,215	1,136,551	0.0014	0.9986	98.98
10.5	813,300,230	1,220,518	0.0015	0.9985	98.85
11.5	781,229,932	1,026,578	0.0013	0.9987	98.70
12.5	744,297,984	1,367,155	0.0018	0.9982	98.57
13.5	708,494,259	1,138,223	0.0016	0.9984	98.39
14.5	679,153,851	1,345,193	0.0020	0.9980	98.23
15.5	652,421,785	1,210,345	0.0019	0.9981	98.03
16.5	625,722,420	1,358,734	0.0022	0.9978	97.85
17.5	589,213,251	1,257,630	0.0021	0.9979	97.64
18.5	567,110,989	1,160,434	0.0020	0.9980	97.43
19.5	535,953,720	1,269,277	0.0024	0.9976	97.23
20.5	495,286,515	1,043,456	0.0021	0.9979	97.00
21.5	459,085,944	1,492,826	0.0033	0.9967	96.80
22.5	426,441,390	1,015,784	0.0024	0.9976	96.48
23.5	404,407,553	1,266,818	0.0031	0.9969	96.25
24.5	389,169,528	1,161,635	0.0030	0.9970	95.95
25.5	369,304,509	1,064,007	0.0029	0.9971	95.66
26.5	349,780,369	975,646	0.0028	0.9972	95.39
27.5	322,226,316	1,275,518	0.0040	0.9960	95.12
28.5	295,997,367	1,129,919	0.0038	0.9962	94.75
29.5	270,713,800	945,595	0.0035	0.9965	94.39
30.5	253,767,133	897,093	0.0035	0.9965	94.06
31.5	237,936,509	823,436	0.0035	0.9965	93.72
32.5	225,899,910	884,264	0.0039	0.9961	93.40
33.5	215,827,538	863,364	0.0040	0.9960	93.03
34.5	208,588,002	772,330	0.0037	0.9963	92.66
35.5	192,449,098	1,045,801	0.0054	0.9946	92.32
36.5	178,042,783	942,664	0.0053	0.9947	91.82
37.5	162,367,183	923,504	0.0057	0.9943	91.33
38.5	152,769,231	862,412	0.0056	0.9944	90.81

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS – PRIMARILY STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1852-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	145,310,834	859,160	0.0059	0.9941	90.30
40.5	138,738,307	795,710	0.0057	0.9943	89.76
41.5	133,401,087	736,879	0.0055	0.9945	89.25
42.5	127,456,303	617,278	0.0048	0.9952	88.76
43.5	121,685,267	770,618	0.0063	0.9937	88.33
44.5	115,399,596	594,897	0.0052	0.9948	87.77
45.5	107,164,130	617,525	0.0058	0.9942	87.31
46.5	100,537,811	690,679	0.0069	0.9931	86.81
47.5	93,770,867	676,355	0.0072	0.9928	86.21
48.5	85,598,222	600,021	0.0070	0.9930	85.59
49.5	77,484,611	718,891	0.0093	0.9907	84.99
50.5	70,699,820	700,736	0.0099	0.9901	84.20
51.5	64,188,613	760,665	0.0119	0.9881	83.37
52.5	57,989,584	621,928	0.0107	0.9893	82.38
53.5	51,507,943	538,788	0.0105	0.9895	81.50
54.5	46,259,822	720,300	0.0156	0.9844	80.65
55.5	42,371,007	477,606	0.0113	0.9887	79.39
56.5	38,608,959	528,679	0.0137	0.9863	78.50
57.5	34,416,730	440,267	0.0128	0.9872	77.42
58.5	30,908,863	421,110	0.0136	0.9864	76.43
59.5	27,320,491	351,266	0.0129	0.9871	75.39
60.5	23,619,073	370,595	0.0157	0.9843	74.42
61.5	20,624,660	520,045	0.0252	0.9748	73.25
62.5	18,722,377	357,106	0.0191	0.9809	71.40
63.5	16,908,359	237,739	0.0141	0.9859	70.04
64.5	15,313,804	491,321	0.0321	0.9679	69.06
65.5	13,814,865	249,686	0.0181	0.9819	66.84
66.5	13,089,301	355,180	0.0271	0.9729	65.63
67.5	10,994,047	212,762	0.0194	0.9806	63.85
68.5	10,529,226	256,625	0.0244	0.9756	62.62
69.5	10,112,360	255,050	0.0252	0.9748	61.09
70.5	9,750,153	193,428	0.0198	0.9802	59.55
71.5	9,144,688	193,787	0.0212	0.9788	58.37
72.5	9,038,421	228,533	0.0253	0.9747	57.13
73.5	8,765,417	202,792	0.0231	0.9769	55.69
74.5	8,554,234	198,679	0.0232	0.9768	54.40
75.5	8,347,235	171,947	0.0206	0.9794	53.14
76.5	8,098,486	163,194	0.0202	0.9798	52.04
77.5	7,934,760	167,130	0.0211	0.9789	50.99
78.5	7,737,607	139,885	0.0181	0.9819	49.92

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS – PRIMARILY STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1852-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	7,588,304	153,607	0.0202	0.9798	49.02
80.5	7,460,598	173,540	0.0233	0.9767	48.02
81.5	7,231,771	173,764	0.0240	0.9760	46.91
82.5	7,043,707	160,251	0.0228	0.9772	45.78
83.5	6,845,740	244,180	0.0357	0.9643	44.74
84.5	6,581,785	216,940	0.0330	0.9670	43.14
85.5	6,274,525	174,096	0.0277	0.9723	41.72
86.5	5,670,282	211,704	0.0373	0.9627	40.56
87.5	4,966,496	165,387	0.0333	0.9667	39.05
88.5	4,551,184	158,296	0.0348	0.9652	37.75
89.5	4,154,011	101,294	0.0244	0.9756	36.44
90.5	3,884,849	160,997	0.0414	0.9586	35.55
91.5	3,310,785	79,014	0.0239	0.9761	34.07
92.5	3,056,387	123,076	0.0403	0.9597	33.26
93.5	2,512,265	117,571	0.0468	0.9532	31.92
94.5	2,271,039	81,424	0.0359	0.9641	30.43
95.5	2,060,418	49,360	0.0240	0.9760	29.34
96.5	1,920,251	39,979	0.0208	0.9792	28.63
97.5	1,835,541	41,561	0.0226	0.9774	28.04
98.5	1,755,246	34,277	0.0195	0.9805	27.40
99.5	1,722,494	51,635	0.0300	0.9700	26.87
100.5	1,624,636	44,692	0.0275	0.9725	26.06
101.5	1,534,707	38,334	0.0250	0.9750	25.35
102.5	1,440,995	40,705	0.0282	0.9718	24.71
103.5	1,336,893	47,039	0.0352	0.9648	24.01
104.5	1,261,925	45,660	0.0362	0.9638	23.17
105.5	1,169,829	60,058	0.0513	0.9487	22.33
106.5	1,053,385	48,021	0.0456	0.9544	21.18
107.5	965,035	136,226	0.1412	0.8588	20.22
108.5	803,160	31,217	0.0389	0.9611	17.36
109.5	717,266	38,450	0.0536	0.9464	16.69
110.5	647,406	33,167	0.0512	0.9488	15.79
111.5	583,610	25,045	0.0429	0.9571	14.99
112.5	536,101	52,679	0.0983	0.9017	14.34
113.5	455,652	16,678	0.0366	0.9634	12.93
114.5	418,905	20,391	0.0487	0.9513	12.46
115.5	390,494	17,282	0.0443	0.9557	11.85
116.5	352,340	22,253	0.0632	0.9368	11.33
117.5	301,254	9,632	0.0320	0.9680	10.61
118.5	280,611	11,179	0.0398	0.9602	10.27

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS – PRIMARILY STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1852-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	262,710	10,972	0.0418	0.9582	9.86
120.5	245,483	15,024	0.0612	0.9388	9.45
121.5	220,344	11,741	0.0533	0.9467	8.87
122.5	203,488	14,762	0.0725	0.9275	8.40
123.5	186,228	9,150	0.0491	0.9509	7.79
124.5	173,972	4,821	0.0277	0.9723	7.41
125.5	167,419	4,640	0.0277	0.9723	7.20
126.5	159,317	7,171	0.0450	0.9550	7.00
127.5	149,499	5,872	0.0393	0.9607	6.69
128.5	142,438	7,630	0.0536	0.9464	6.43
129.5	131,854	6,777	0.0514	0.9486	6.08
130.5	124,950	5,100	0.0408	0.9592	5.77
131.5	115,842	3,209	0.0277	0.9723	5.53
132.5	111,661	4,664	0.0418	0.9582	5.38
133.5	106,814	4,334	0.0406	0.9594	5.16
134.5	100,650	5,214	0.0518	0.9482	4.95
135.5	93,280	3,138	0.0336	0.9664	4.69
136.5	88,419	7,399	0.0837	0.9163	4.53
137.5	79,578	5,560	0.0699	0.9301	4.15
138.5	73,860	4,840	0.0655	0.9345	3.86
139.5	67,461	3,462	0.0513	0.9487	3.61
140.5	62,703	8,832	0.1409	0.8591	3.42
141.5	52,680	3,847	0.0730	0.9270	2.94
142.5	48,653	11,480	0.2360	0.7640	2.73
143.5	37,093	7,333	0.1977	0.8023	2.08
144.5	26,219	2,052	0.0783	0.9217	1.67
145.5	21,387	1,804	0.0844	0.9156	1.54
146.5	19,132	2,466	0.1289	0.8711	1.41
147.5	14,436	1,427	0.0988	0.9012	1.23
148.5	12,860	14,575	1.1334	0.1334-	1.11
149.5	11,686	392	0.0335		
150.5	11,020	113	0.0103		
151.5	10,907	955	0.0875		
152.5	9,837	253	0.0257		
153.5	9,584	1,024	0.1068		
154.5	8,560	1,120	0.1308		
155.5	7,440	407	0.0546		
156.5	7,034	1,399	0.1989		
157.5	3,366	512	0.1522		
158.5	2,851	394	0.1383		

UGI UTILITIES, INC. - GAS DIVISION

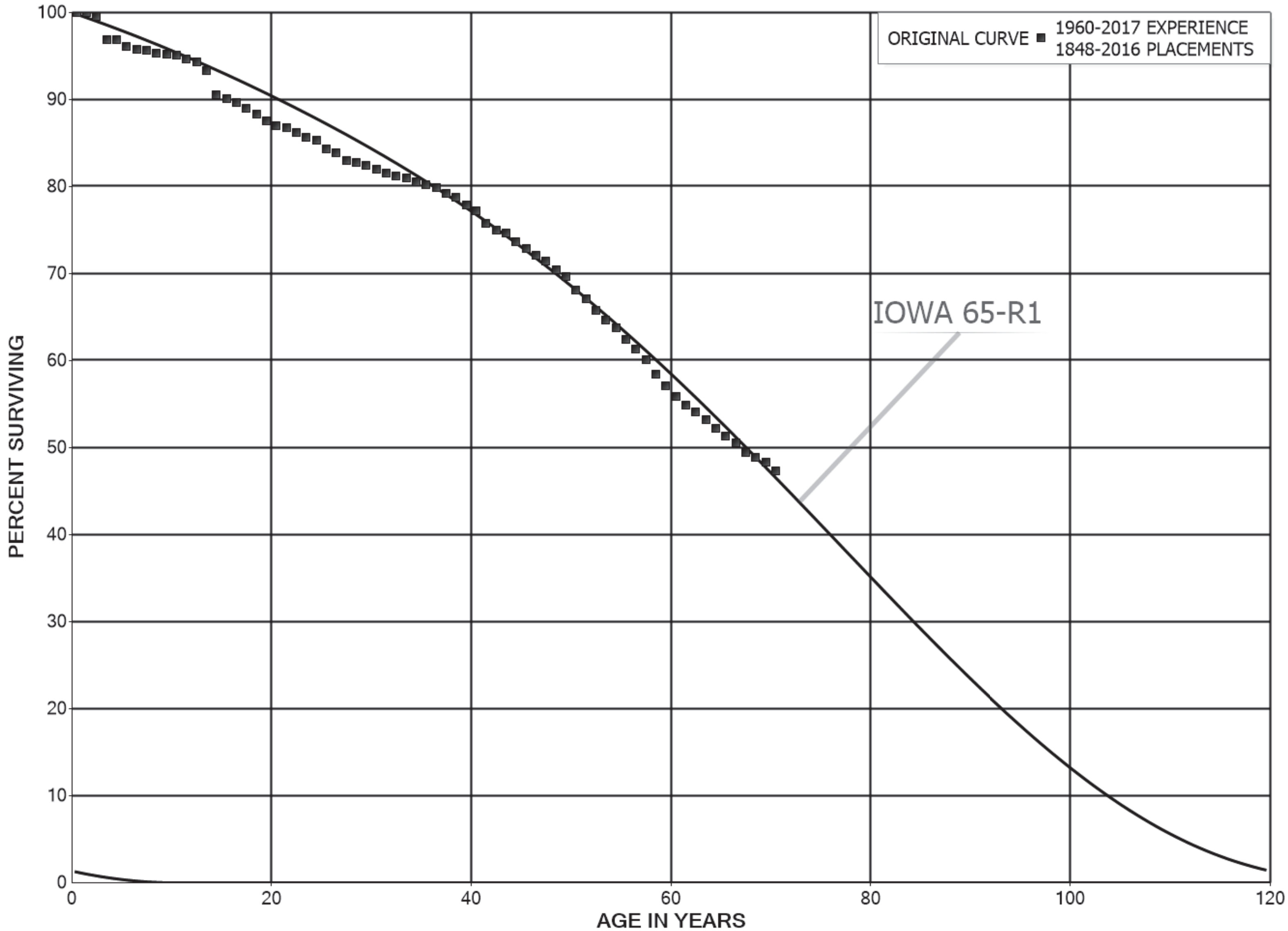
ACCOUNT 376.1 MAINS – PRIMARILY STEEL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1852-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
159.5	2,116	73	0.0346		
160.5	2,043	1,667	0.8160		
161.5	376	376	1.0000		
162.5					

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 376.2 MAINS - CAST IRON
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE

PLACEMENT BAND 1848-2016 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	128,340		0.0000	1.0000	100.00
0.5	417,047		0.0000	1.0000	100.00
1.5	686,486	3,376	0.0049	0.9951	100.00
2.5	999,617	26,728	0.0267	0.9733	99.51
3.5	1,231,967	525	0.0004	0.9996	96.85
4.5	1,437,913	11,504	0.0080	0.9920	96.81
5.5	1,643,312	5,158	0.0031	0.9969	96.03
6.5	1,911,000	2,734	0.0014	0.9986	95.73
7.5	2,108,714	6,671	0.0032	0.9968	95.59
8.5	2,302,901	1,972	0.0009	0.9991	95.29
9.5	2,511,213	3,127	0.0012	0.9988	95.21
10.5	2,677,251	14,625	0.0055	0.9945	95.09
11.5	2,791,786	8,394	0.0030	0.9970	94.57
12.5	2,903,598	31,594	0.0109	0.9891	94.29
13.5	2,934,288	86,763	0.0296	0.9704	93.26
14.5	2,873,867	13,462	0.0047	0.9953	90.50
15.5	2,878,337	15,246	0.0053	0.9947	90.08
16.5	2,926,102	21,862	0.0075	0.9925	89.60
17.5	2,935,995	19,803	0.0067	0.9933	88.93
18.5	3,001,136	26,985	0.0090	0.9910	88.33
19.5	3,014,954	18,325	0.0061	0.9939	87.54
20.5	3,040,046	9,333	0.0031	0.9969	87.01
21.5	3,067,923	18,431	0.0060	0.9940	86.74
22.5	3,077,259	21,917	0.0071	0.9929	86.22
23.5	3,080,393	12,031	0.0039	0.9961	85.60
24.5	3,079,582	34,170	0.0111	0.9889	85.27
25.5	3,053,713	16,511	0.0054	0.9946	84.32
26.5	3,076,526	33,572	0.0109	0.9891	83.87
27.5	3,068,839	9,579	0.0031	0.9969	82.95
28.5	3,108,809	10,891	0.0035	0.9965	82.69
29.5	3,237,599	16,633	0.0051	0.9949	82.40
30.5	3,429,653	18,628	0.0054	0.9946	81.98
31.5	3,610,043	15,311	0.0042	0.9958	81.54
32.5	3,814,081	8,873	0.0023	0.9977	81.19
33.5	4,095,185	26,216	0.0064	0.9936	81.00
34.5	4,372,461	19,307	0.0044	0.9956	80.48
35.5	4,876,394	18,656	0.0038	0.9962	80.13
36.5	5,197,717	43,775	0.0084	0.9916	79.82
37.5	5,300,260	29,004	0.0055	0.9945	79.15
38.5	5,346,838	56,405	0.0105	0.9895	78.72

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1848-2016 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,378,921	45,417	0.0084	0.9916	77.88
40.5	5,392,840	106,710	0.0198	0.9802	77.23
41.5	5,323,657	51,809	0.0097	0.9903	75.70
42.5	5,346,569	26,553	0.0050	0.9950	74.96
43.5	5,415,071	71,600	0.0132	0.9868	74.59
44.5	5,419,761	55,266	0.0102	0.9898	73.60
45.5	5,397,712	59,045	0.0109	0.9891	72.85
46.5	5,370,661	49,771	0.0093	0.9907	72.06
47.5	5,383,675	78,203	0.0145	0.9855	71.39
48.5	5,348,540	54,614	0.0102	0.9898	70.35
49.5	5,350,780	121,699	0.0227	0.9773	69.63
50.5	5,283,774	73,442	0.0139	0.9861	68.05
51.5	5,267,029	107,777	0.0205	0.9795	67.10
52.5	5,206,850	88,984	0.0171	0.9829	65.73
53.5	5,188,190	75,165	0.0145	0.9855	64.61
54.5	5,170,494	102,717	0.0199	0.9801	63.67
55.5	5,119,160	90,862	0.0177	0.9823	62.41
56.5	5,078,108	101,285	0.0199	0.9801	61.30
57.5	5,007,156	142,549	0.0285	0.9715	60.08
58.5	4,761,850	104,432	0.0219	0.9781	58.37
59.5	4,596,256	99,511	0.0217	0.9783	57.09
60.5	4,379,576	75,308	0.0172	0.9828	55.85
61.5	4,176,343	67,031	0.0161	0.9839	54.89
62.5	4,005,817	65,398	0.0163	0.9837	54.01
63.5	3,864,841	72,164	0.0187	0.9813	53.13
64.5	3,689,487	57,730	0.0156	0.9844	52.13
65.5	3,571,522	59,055	0.0165	0.9835	51.32
66.5	3,449,326	75,274	0.0218	0.9782	50.47
67.5	3,300,272	36,590	0.0111	0.9889	49.37
68.5	3,244,695	33,170	0.0102	0.9898	48.82
69.5	3,182,535	65,063	0.0204	0.9796	48.32
70.5	3,082,983	35,336	0.0115	0.9885	47.33
71.5	3,049,210	35,541	0.0117	0.9883	46.79
72.5	3,022,895	47,143	0.0156	0.9844	46.25
73.5	2,993,113	43,271	0.0145	0.9855	45.53
74.5	2,955,725	43,302	0.0147	0.9853	44.87
75.5	2,921,655	42,664	0.0146	0.9854	44.21
76.5	2,874,345	38,191	0.0133	0.9867	43.56
77.5	2,842,024	47,934	0.0169	0.9831	42.99
78.5	2,787,135	39,758	0.0143	0.9857	42.26

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1848-2016 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	2,758,542	61,953	0.0225	0.9775	41.66
80.5	2,697,984	48,668	0.0180	0.9820	40.72
81.5	2,648,703	43,140	0.0163	0.9837	39.99
82.5	2,607,995	61,921	0.0237	0.9763	39.34
83.5	2,554,893	77,495	0.0303	0.9697	38.40
84.5	2,486,065	64,310	0.0259	0.9741	37.24
85.5	2,423,746	65,750	0.0271	0.9729	36.27
86.5	2,379,274	107,699	0.0453	0.9547	35.29
87.5	2,236,079	55,180	0.0247	0.9753	33.69
88.5	2,106,932	52,723	0.0250	0.9750	32.86
89.5	2,009,194	61,074	0.0304	0.9696	32.04
90.5	1,875,328	80,781	0.0431	0.9569	31.07
91.5	1,715,204	31,471	0.0183	0.9817	29.73
92.5	1,599,246	67,742	0.0424	0.9576	29.18
93.5	1,362,129	61,171	0.0449	0.9551	27.95
94.5	1,245,247	27,328	0.0219	0.9781	26.69
95.5	1,133,443	16,560	0.0146	0.9854	26.10
96.5	1,078,418	24,507	0.0227	0.9773	25.72
97.5	1,020,426	27,768	0.0272	0.9728	25.14
98.5	965,946	19,849	0.0205	0.9795	24.45
99.5	939,424	26,105	0.0278	0.9722	23.95
100.5	891,793	33,048	0.0371	0.9629	23.29
101.5	834,039	25,470	0.0305	0.9695	22.42
102.5	783,694	25,030	0.0319	0.9681	21.74
103.5	751,460	24,598	0.0327	0.9673	21.04
104.5	722,965	23,428	0.0324	0.9676	20.36
105.5	682,279	19,161	0.0281	0.9719	19.70
106.5	651,978	29,291	0.0449	0.9551	19.14
107.5	603,604	21,814	0.0361	0.9639	18.28
108.5	568,139	23,872	0.0420	0.9580	17.62
109.5	525,492	23,373	0.0445	0.9555	16.88
110.5	487,128	19,623	0.0403	0.9597	16.13
111.5	460,497	19,170	0.0416	0.9584	15.48
112.5	426,212	22,948	0.0538	0.9462	14.84
113.5	387,431	14,235	0.0367	0.9633	14.04
114.5	359,113	15,198	0.0423	0.9577	13.52
115.5	338,534	12,985	0.0384	0.9616	12.95
116.5	311,620	9,861	0.0316	0.9684	12.45
117.5	274,429	5,805	0.0212	0.9788	12.06
118.5	259,046	8,731	0.0337	0.9663	11.80

PLACEMENT BAND 1848-2016 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	244,060	8,970	0.0368	0.9632	11.41
120.5	230,887	8,611	0.0373	0.9627	10.99
121.5	213,312	10,709	0.0502	0.9498	10.58
122.5	197,630	12,248	0.0620	0.9380	10.05
123.5	184,192	6,880	0.0374	0.9626	9.42
124.5	174,430	5,275	0.0302	0.9698	9.07
125.5	167,780	5,680	0.0339	0.9661	8.80
126.5	158,677	7,867	0.0496	0.9504	8.50
127.5	148,344	6,389	0.0431	0.9569	8.08
128.5	140,647	7,636	0.0543	0.9457	7.73
129.5	130,463	6,025	0.0462	0.9538	7.31
130.5	124,312	5,200	0.0418	0.9582	6.97
131.5	115,451	3,206	0.0278	0.9722	6.68
132.5	111,275	4,076	0.0366	0.9634	6.50
133.5	107,016	4,334	0.0405	0.9595	6.26
134.5	100,933	5,217	0.0517	0.9483	6.00
135.5	94,066	3,138	0.0334	0.9666	5.69
136.5	89,433	7,746	0.0866	0.9134	5.50
137.5	81,157	5,166	0.0637	0.9363	5.03
138.5	75,836	4,507	0.0594	0.9406	4.71
139.5	69,784	3,168	0.0454	0.9546	4.43
140.5	65,319	8,832	0.1352	0.8648	4.23
141.5	55,331	2,997	0.0542	0.9458	3.66
142.5	52,156	11,480	0.2201	0.7799	3.46
143.5	40,674	7,782	0.1913	0.8087	2.70
144.5	29,398	2,140	0.0728	0.9272	2.18
145.5	24,478	1,894	0.0774	0.9226	2.02
146.5	22,133	2,525	0.1141	0.8859	1.87
147.5	17,393	1,435	0.0825	0.9175	1.65
148.5	15,814	882	0.0558	0.9442	1.52
149.5	14,679	392	0.0267	0.9733	1.43
150.5	14,045	113	0.0081	0.9919	1.39
151.5	13,932	1,042	0.0748	0.9252	1.38
152.5	12,775	1,224	0.0958	0.9042	1.28
153.5	11,551	1,024	0.0886	0.9114	1.16
154.5	10,527	1,120	0.1064	0.8936	1.05
155.5	9,407	410	0.0435	0.9565	0.94
156.5	8,998	1,399	0.1554	0.8446	0.90
157.5	5,478	512	0.0935	0.9065	0.76
158.5	4,966	1,175	0.2366	0.7634	0.69

UGI UTILITIES, INC. - GAS DIVISION

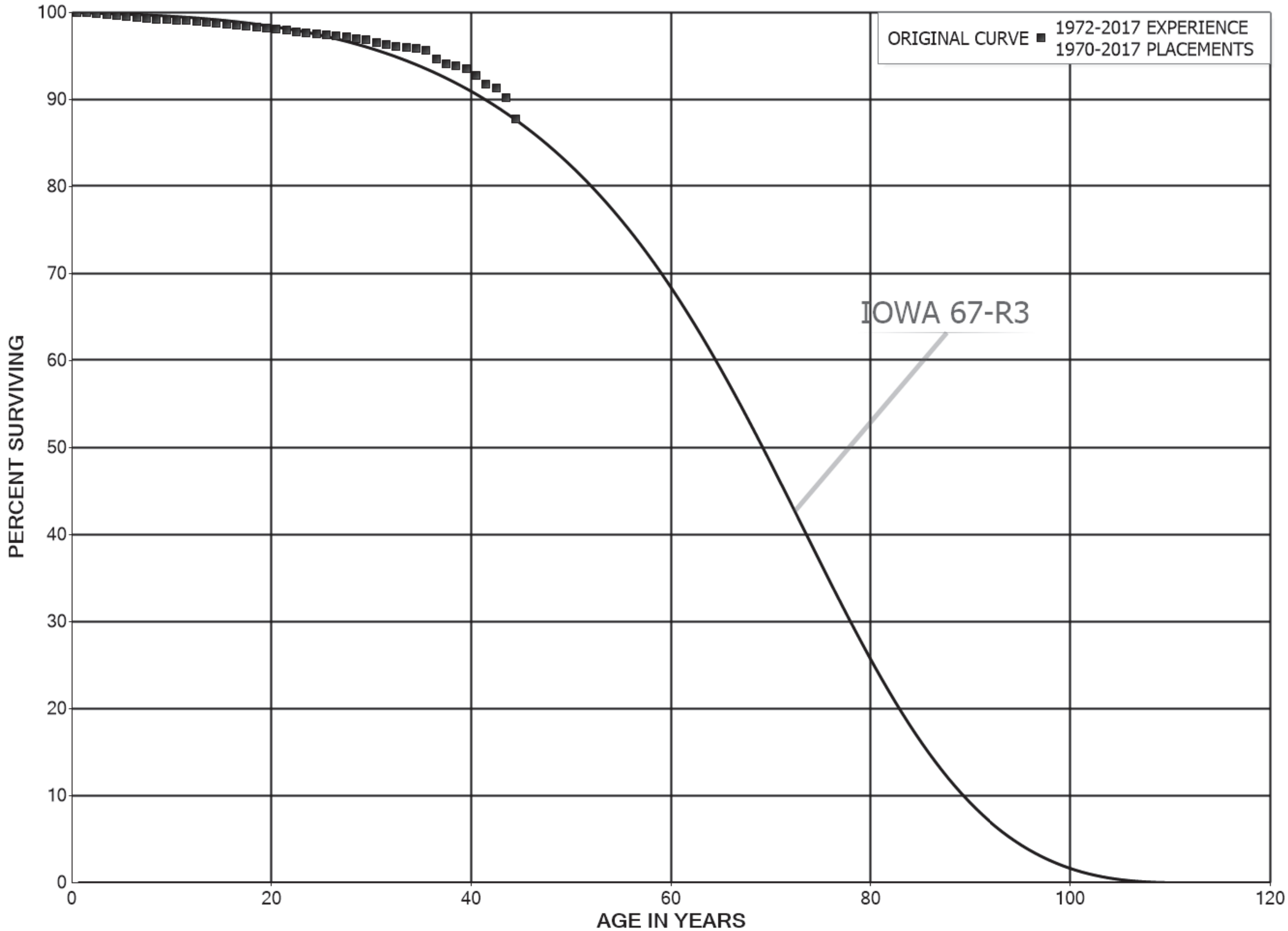
ACCOUNT 376.2 MAINS - CAST IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1848-2016 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
159.5	3,791	345	0.0909	0.9091	0.53
160.5	3,446	1,778	0.5160	0.4840	0.48
161.5	1,668	1,149	0.6888	0.3112	0.23
162.5	519	389	0.7488	0.2512	0.07
163.5	130	46	0.3492	0.6508	0.02
164.5	85	85	1.0000		0.01
165.5					

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 376.3 MAINS - PLASTIC
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2017 EXPERIENCE BAND 1972-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	735,790,771	9,608	0.0000	1.0000	100.00
0.5	709,882,465	547,462	0.0008	0.9992	100.00
1.5	631,633,067	567,036	0.0009	0.9991	99.92
2.5	585,519,663	507,859	0.0009	0.9991	99.83
3.5	543,748,206	469,515	0.0009	0.9991	99.75
4.5	506,432,651	699,548	0.0014	0.9986	99.66
5.5	474,195,883	396,516	0.0008	0.9992	99.52
6.5	451,372,228	621,391	0.0014	0.9986	99.44
7.5	434,157,606	386,338	0.0009	0.9991	99.30
8.5	416,958,426	194,324	0.0005	0.9995	99.21
9.5	400,065,769	364,833	0.0009	0.9991	99.17
10.5	379,569,306	216,681	0.0006	0.9994	99.08
11.5	360,864,726	400,539	0.0011	0.9989	99.02
12.5	339,360,535	345,042	0.0010	0.9990	98.91
13.5	316,805,514	264,012	0.0008	0.9992	98.81
14.5	297,816,558	334,714	0.0011	0.9989	98.73
15.5	283,988,236	317,167	0.0011	0.9989	98.62
16.5	265,385,355	264,756	0.0010	0.9990	98.51
17.5	250,016,280	284,070	0.0011	0.9989	98.41
18.5	233,962,055	227,581	0.0010	0.9990	98.30
19.5	216,213,397	243,477	0.0011	0.9989	98.20
20.5	191,822,813	318,486	0.0017	0.9983	98.09
21.5	175,409,977	342,482	0.0020	0.9980	97.93
22.5	153,966,971	161,155	0.0010	0.9990	97.74
23.5	138,701,899	171,761	0.0012	0.9988	97.63
24.5	130,545,875	148,184	0.0011	0.9989	97.51
25.5	120,516,035	113,131	0.0009	0.9991	97.40
26.5	108,909,038	98,612	0.0009	0.9991	97.31
27.5	88,795,710	259,925	0.0029	0.9971	97.22
28.5	70,583,911	108,170	0.0015	0.9985	96.94
29.5	53,558,175	171,811	0.0032	0.9968	96.79
30.5	42,110,330	75,282	0.0018	0.9982	96.48
31.5	35,402,179	97,627	0.0028	0.9972	96.31
32.5	30,234,813	37,273	0.0012	0.9988	96.04
33.5	25,597,580	27,392	0.0011	0.9989	95.92
34.5	22,243,152	51,161	0.0023	0.9977	95.82
35.5	18,467,095	199,975	0.0108	0.9892	95.60
36.5	15,177,749	71,466	0.0047	0.9953	94.56
37.5	11,755,852	31,002	0.0026	0.9974	94.12
38.5	9,137,842	39,104	0.0043	0.9957	93.87

UGI UTILITIES, INC. - GAS DIVISION

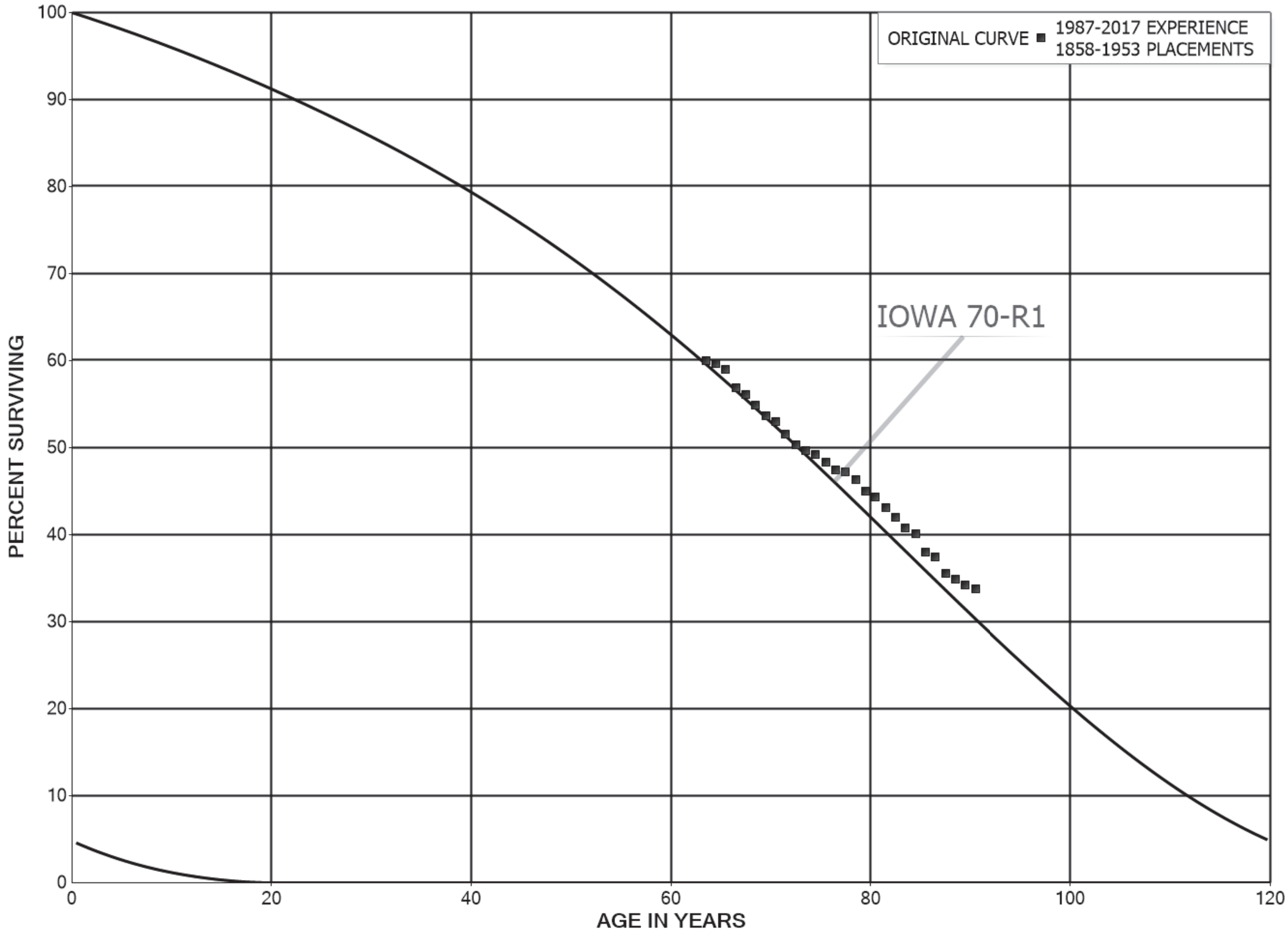
ACCOUNT 376.3 MAINS - PLASTIC

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1970-2017 EXPERIENCE BAND 1972-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,583,890	55,957	0.0085	0.9915	93.47
40.5	4,674,117	45,106	0.0097	0.9903	92.67
41.5	2,969,020	17,225	0.0058	0.9942	91.78
42.5	1,262,881	14,736	0.0117	0.9883	91.25
43.5	604,484	16,801	0.0278	0.9722	90.18
44.5	34,973	209	0.0060	0.9940	87.68
45.5	11,209		0.0000	1.0000	87.15
46.5	2,846		0.0000	1.0000	87.15
47.5					87.15

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

ORIGINAL LIFE TABLE

PLACEMENT BAND 1858-1953 EXPERIENCE BAND 1987-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0					
0.5					
1.5					
2.5					
3.5					
4.5					
5.5					
6.5					
7.5					
8.5					
9.5					
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19.5					
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25.5					
26.5					
27.5					
28.5					
29.5					
30.5					
31.5					
32.5					
33.5					
34.5					
35.5					
36.5					
37.5					
38.5					

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1858-1953 EXPERIENCE BAND 1987-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5					
40.5					
41.5					
42.5					
43.5					
44.5					
45.5					
46.5					
47.5					
48.5					
49.5					
50.5					
51.5					
52.5					
53.5					
54.5					
55.5					
56.5					
57.5					
58.5					
59.5					
60.5					
61.5					
62.5	74,822		0.0000		
63.5	138,090	982	0.0071	0.9929	60.00
64.5	160,344	1,746	0.0109	0.9891	59.57
65.5	180,134	6,379	0.0354	0.9646	58.92
66.5	180,863	2,380	0.0132	0.9868	56.84
67.5	187,809	4,157	0.0221	0.9779	56.09
68.5	193,504	4,443	0.0230	0.9770	54.85
69.5	197,529	2,263	0.0115	0.9885	53.59
70.5	240,482	6,495	0.0270	0.9730	52.98
71.5	267,584	6,528	0.0244	0.9756	51.54
72.5	355,036	4,768	0.0134	0.9866	50.29
73.5	376,789	3,224	0.0086	0.9914	49.61
74.5	393,509	6,859	0.0174	0.9826	49.19
75.5	415,072	7,571	0.0182	0.9818	48.33
76.5	418,418	2,828	0.0068	0.9932	47.45
77.5	426,142	7,691	0.0180	0.9820	47.13
78.5	427,057	12,197	0.0286	0.9714	46.28

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1858-1953 EXPERIENCE BAND 1987-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	418,582	6,709	0.0160	0.9840	44.96
80.5	432,716	11,196	0.0259	0.9741	44.23
81.5	427,328	11,347	0.0266	0.9734	43.09
82.5	423,785	12,079	0.0285	0.9715	41.95
83.5	395,943	6,256	0.0158	0.9842	40.75
84.5	390,467	20,870	0.0534	0.9466	40.11
85.5	372,665	5,350	0.0144	0.9856	37.96
86.5	368,309	19,184	0.0521	0.9479	37.42
87.5	350,796	6,569	0.0187	0.9813	35.47
88.5	344,803	6,292	0.0182	0.9818	34.80
89.5	338,948	4,763	0.0141	0.9859	34.17
90.5	333,595	26,701	0.0800	0.9200	33.69
91.5	321,596	1,363	0.0042	0.9958	30.99
92.5	320,406	3,941	0.0123	0.9877	30.86
93.5	270,178	1,710	0.0063	0.9937	30.48
94.5	254,123	2,890	0.0114	0.9886	30.29
95.5	237,335	1,741	0.0073	0.9927	29.94
96.5	227,525	1,183	0.0052	0.9948	29.72
97.5	224,634	1,356	0.0060	0.9940	29.57
98.5	218,115	839	0.0038	0.9962	29.39
99.5	223,803	1	0.0000	1.0000	29.28
100.5	198,724	626	0.0032	0.9968	29.28
101.5	178,461	523	0.0029	0.9971	29.19
102.5	153,710	445	0.0029	0.9971	29.10
103.5	101,151	577	0.0057	0.9943	29.02
104.5	81,128	37	0.0005	0.9995	28.85
105.5	69,235	280	0.0040	0.9960	28.84
106.5	50,608	40	0.0008	0.9992	28.72
107.5	41,716		0.0000	1.0000	28.70
108.5	35,344	143	0.0040	0.9960	28.70
109.5	28,731	2	0.0001	0.9999	28.58
110.5	25,717	9	0.0003	0.9997	28.58
111.5	21,129	1	0.0000	1.0000	28.57
112.5	18,544	954	0.0514	0.9486	28.57
113.5	10,777	84	0.0078	0.9922	27.10
114.5	7,909	95	0.0120	0.9880	26.89
115.5	6,956	16	0.0024	0.9976	26.57
116.5	5,279	64	0.0121	0.9879	26.50
117.5	5,004	70	0.0139	0.9861	26.18
118.5	4,017		0.0000	1.0000	25.82

UGI UTILITIES, INC. - GAS DIVISION

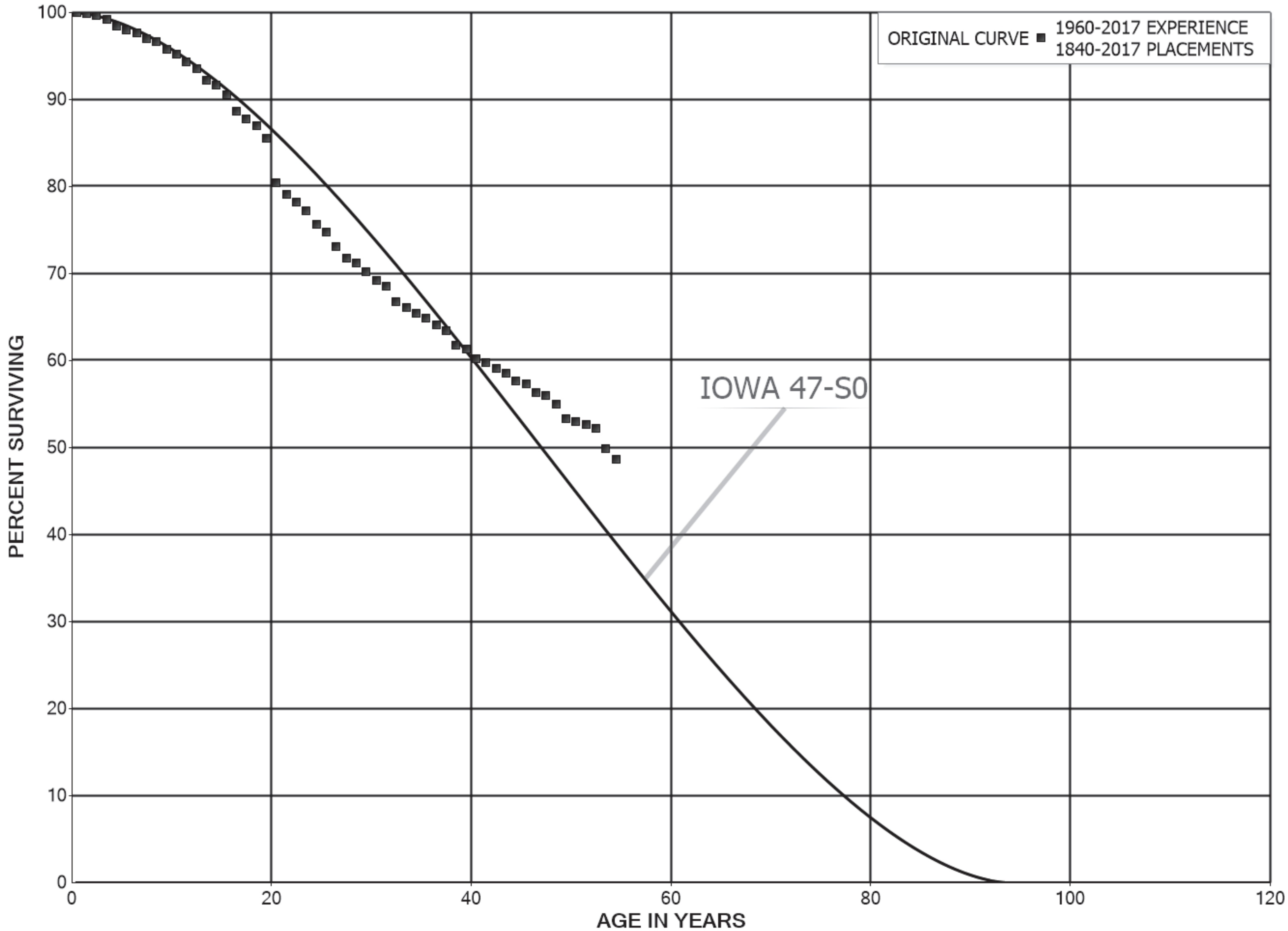
ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1858-1953 EXPERIENCE BAND 1987-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	3,812	30	0.0078	0.9922	25.82
120.5	3,713	186	0.0502	0.9498	25.62
121.5	3,326	3	0.0008	0.9992	24.33
122.5	3,259	174	0.0533	0.9467	24.31
123.5	3,084		0.0000	1.0000	23.02
124.5	2,861	165	0.0577	0.9423	23.02
125.5	2,896	319	0.1102	0.8898	21.69
126.5	2,538		0.0000	1.0000	19.30
127.5	2,510	54	0.0214	0.9786	19.30
128.5	2,577		0.0000	1.0000	18.89
129.5	2,522	141	0.0560	0.9440	18.89
130.5	2,381		0.0000	1.0000	17.83
131.5	2,378	3	0.0013	0.9987	17.83
132.5	2,375		0.0000	1.0000	17.80
133.5	2,375	1	0.0004	0.9996	17.80
134.5	2,293		0.0000	1.0000	17.80
135.5	1,787		0.0000	1.0000	17.80
136.5	1,558		0.0000	1.0000	17.80
137.5	647		0.0000	1.0000	17.80
138.5	645		0.0000	1.0000	17.80
139.5	645	4	0.0064	0.9936	17.80
140.5	641		0.0000	1.0000	17.68
141.5	641		0.0000	1.0000	17.68
142.5	639		0.0000	1.0000	17.68
143.5	614		0.0000	1.0000	17.68
144.5	569		0.0000	1.0000	17.68
145.5	569	9	0.0155	0.9845	17.68
146.5	560		0.0000	1.0000	17.41
147.5	546		0.0000	1.0000	17.41
148.5	540		0.0000	1.0000	17.41
149.5	523		0.0000	1.0000	17.41
150.5	491		0.0000	1.0000	17.41
151.5	491		0.0000	1.0000	17.41
152.5	491		0.0000	1.0000	17.41
153.5	491		0.0000	1.0000	17.41
154.5	491		0.0000	1.0000	17.41
155.5	491		0.0000	1.0000	17.41
156.5	491		0.0000	1.0000	17.41
157.5	343		0.0000	1.0000	17.41
158.5	341		0.0000	1.0000	17.41
159.5					17.41

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1840-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	74,215,652	75,374	0.0010	0.9990	100.00
0.5	71,644,528	34,225	0.0005	0.9995	99.90
1.5	66,602,229	128,931	0.0019	0.9981	99.85
2.5	56,586,240	282,481	0.0050	0.9950	99.66
3.5	51,285,411	410,764	0.0080	0.9920	99.16
4.5	50,414,884	208,507	0.0041	0.9959	98.37
5.5	45,763,935	142,729	0.0031	0.9969	97.96
6.5	41,055,811	317,629	0.0077	0.9923	97.65
7.5	40,304,183	117,659	0.0029	0.9971	96.90
8.5	39,261,790	343,148	0.0087	0.9913	96.62
9.5	36,237,607	222,112	0.0061	0.9939	95.77
10.5	34,068,793	303,295	0.0089	0.9911	95.18
11.5	32,531,987	275,438	0.0085	0.9915	94.34
12.5	30,621,088	428,150	0.0140	0.9860	93.54
13.5	28,171,858	180,550	0.0064	0.9936	92.23
14.5	25,364,169	305,701	0.0121	0.9879	91.64
15.5	24,308,209	522,920	0.0215	0.9785	90.53
16.5	22,436,230	204,479	0.0091	0.9909	88.59
17.5	20,642,674	193,702	0.0094	0.9906	87.78
18.5	20,044,820	326,734	0.0163	0.9837	86.96
19.5	18,485,691	1,116,662	0.0604	0.9396	85.54
20.5	16,185,509	256,162	0.0158	0.9842	80.37
21.5	14,629,875	175,871	0.0120	0.9880	79.10
22.5	13,511,223	170,321	0.0126	0.9874	78.15
23.5	12,616,141	246,830	0.0196	0.9804	77.16
24.5	12,001,687	147,946	0.0123	0.9877	75.65
25.5	11,276,508	249,385	0.0221	0.9779	74.72
26.5	10,620,363	191,403	0.0180	0.9820	73.07
27.5	10,099,044	75,398	0.0075	0.9925	71.75
28.5	9,288,610	140,544	0.0151	0.9849	71.22
29.5	8,808,655	125,998	0.0143	0.9857	70.14
30.5	8,198,952	69,949	0.0085	0.9915	69.13
31.5	7,706,475	203,055	0.0263	0.9737	68.55
32.5	7,100,236	73,550	0.0104	0.9896	66.74
33.5	6,843,528	63,836	0.0093	0.9907	66.05
34.5	6,462,754	57,478	0.0089	0.9911	65.43
35.5	5,822,233	69,078	0.0119	0.9881	64.85
36.5	5,021,694	54,254	0.0108	0.9892	64.08
37.5	4,697,283	124,165	0.0264	0.9736	63.39
38.5	4,461,940	28,571	0.0064	0.9936	61.71

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,368,424	80,524	0.0184	0.9816	61.32
40.5	4,039,556	31,303	0.0077	0.9923	60.19
41.5	3,840,956	41,189	0.0107	0.9893	59.72
42.5	3,708,013	39,288	0.0106	0.9894	59.08
43.5	3,504,977	50,594	0.0144	0.9856	58.45
44.5	3,262,575	21,107	0.0065	0.9935	57.61
45.5	3,108,343	53,505	0.0172	0.9828	57.24
46.5	2,678,627	13,873	0.0052	0.9948	56.25
47.5	2,261,833	42,466	0.0188	0.9812	55.96
48.5	1,759,197	50,979	0.0290	0.9710	54.91
49.5	1,503,484	10,392	0.0069	0.9931	53.32
50.5	1,322,143	8,660	0.0065	0.9935	52.95
51.5	1,179,778	9,446	0.0080	0.9920	52.60
52.5	1,014,902	46,607	0.0459	0.9541	52.18
53.5	884,469	19,991	0.0226	0.9774	49.79
54.5	777,030	6,071	0.0078	0.9922	48.66
55.5	702,538	4,076	0.0058	0.9942	48.28
56.5	635,285	2,363	0.0037	0.9963	48.00
57.5	565,058	3,470	0.0061	0.9939	47.82
58.5	543,659	4,229	0.0078	0.9922	47.53
59.5	442,100	3,177	0.0072	0.9928	47.16
60.5	335,171	5,091	0.0152	0.9848	46.82
61.5	228,226	5,010	0.0220	0.9780	46.11
62.5	191,528	6,028	0.0315	0.9685	45.10
63.5	124,801	7,842	0.0628	0.9372	43.68
64.5	100,000	1,930	0.0193	0.9807	40.93
65.5	77,378	3,783	0.0489	0.9511	40.14
66.5	64,453	1,587	0.0246	0.9754	38.18
67.5	46,687	110	0.0024	0.9976	37.24
68.5	45,221	853	0.0189	0.9811	37.15
69.5	41,953	116	0.0028	0.9972	36.45
70.5	38,761	971	0.0251	0.9749	36.35
71.5	37,099		0.0000	1.0000	35.44
72.5	36,718	395	0.0108	0.9892	35.44
73.5	36,323	83	0.0023	0.9977	35.06
74.5	35,348	963	0.0272	0.9728	34.98
75.5	32,134	2,158	0.0672	0.9328	34.03
76.5	29,660	749	0.0253	0.9747	31.74
77.5	28,630	830	0.0290	0.9710	30.94
78.5	27,354	297	0.0109	0.9891	30.04

UGI UTILITIES, INC. - GAS DIVISION

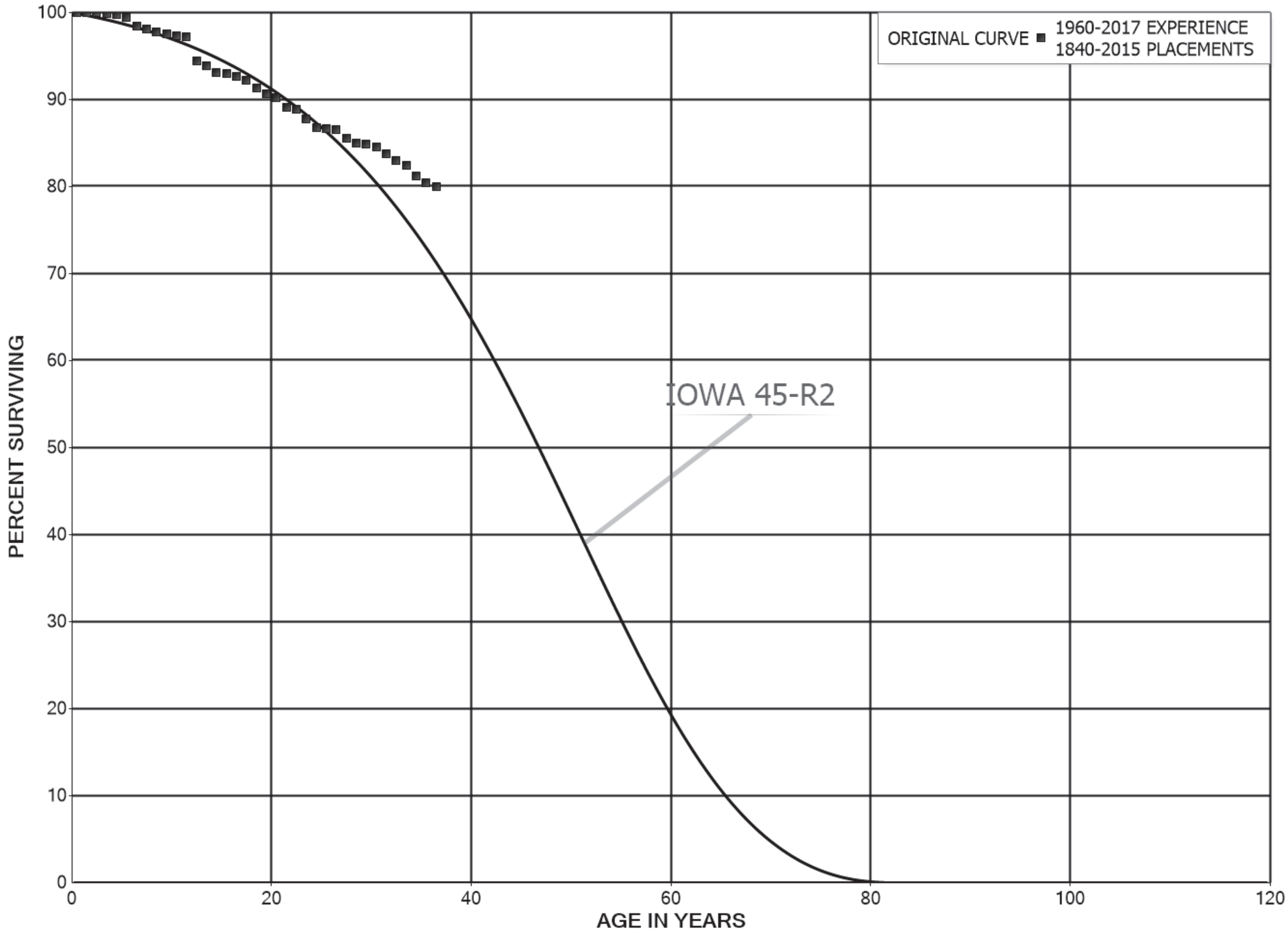
ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	26,595	15	0.0006	0.9994	29.71
80.5	24,152		0.0000	1.0000	29.70
81.5	23,312	647	0.0278	0.9722	29.70
82.5	22,333	1,361	0.0610	0.9390	28.87
83.5	20,698		0.0000	1.0000	27.11
84.5	20,698	774	0.0374	0.9626	27.11
85.5	19,619		0.0000	1.0000	26.10
86.5	17,234	574	0.0333	0.9667	26.10
87.5	15,769	206	0.0131	0.9869	25.23
88.5	14,796	536	0.0363	0.9637	24.90
89.5	12,372	1,735	0.1403	0.8597	24.00
90.5	5,054		0.0000	1.0000	20.63
91.5	3,697	634	0.1715	0.8285	20.63
92.5	3,063		0.0000	1.0000	17.09
93.5	2,098		0.0000	1.0000	17.09
94.5	1,754		0.0000	1.0000	17.09
95.5	1,507		0.0000	1.0000	17.09
96.5	1,446		0.0000	1.0000	17.09
97.5	1,240		0.0000	1.0000	17.09
98.5	373		0.0000	1.0000	17.09
99.5	373		0.0000	1.0000	17.09
100.5	373		0.0000	1.0000	17.09
101.5	192		0.0000	1.0000	17.09
102.5	197		0.0000	1.0000	17.09
103.5	197		0.0000	1.0000	17.09
104.5	197		0.0000	1.0000	17.09
105.5	197		0.0000	1.0000	17.09
106.5	120		0.0000	1.0000	17.09
107.5					17.09

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE
ORIGINAL AND SMOOTH SURVIVOR CURVES



Gannett Fleming

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1840-2015 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	25,395,548	1,443	0.0001	0.9999	100.00
0.5	25,391,662	561	0.0000	1.0000	99.99
1.5	24,813,206	4,935	0.0002	0.9998	99.99
2.5	24,277,250	21,146	0.0009	0.9991	99.97
3.5	15,412,622	22,798	0.0015	0.9985	99.89
4.5	14,949,885	50,659	0.0034	0.9966	99.74
5.5	13,761,469	139,878	0.0102	0.9898	99.40
6.5	12,287,686	34,913	0.0028	0.9972	98.39
7.5	11,570,771	46,316	0.0040	0.9960	98.11
8.5	11,444,544	31,101	0.0027	0.9973	97.72
9.5	10,702,692	18,702	0.0017	0.9983	97.45
10.5	10,955,906	14,416	0.0013	0.9987	97.28
11.5	9,813,918	276,897	0.0282	0.9718	97.15
12.5	9,484,611	54,823	0.0058	0.9942	94.41
13.5	9,352,065	81,287	0.0087	0.9913	93.87
14.5	8,580,388	11,819	0.0014	0.9986	93.05
15.5	8,364,131	27,645	0.0033	0.9967	92.92
16.5	7,973,439	35,761	0.0045	0.9955	92.61
17.5	7,835,783	73,834	0.0094	0.9906	92.20
18.5	7,693,055	62,228	0.0081	0.9919	91.33
19.5	7,252,559	30,422	0.0042	0.9958	90.59
20.5	6,689,803	83,321	0.0125	0.9875	90.21
21.5	5,788,527	19,322	0.0033	0.9967	89.09
22.5	5,451,705	64,131	0.0118	0.9882	88.79
23.5	5,297,596	59,495	0.0112	0.9888	87.75
24.5	5,160,931	7,218	0.0014	0.9986	86.76
25.5	4,832,055	8,220	0.0017	0.9983	86.64
26.5	4,551,818	53,313	0.0117	0.9883	86.49
27.5	4,351,243	26,410	0.0061	0.9939	85.48
28.5	4,261,247	8,163	0.0019	0.9981	84.96
29.5	4,003,816	14,459	0.0036	0.9964	84.80
30.5	3,195,141	29,442	0.0092	0.9908	84.49
31.5	2,899,167	27,478	0.0095	0.9905	83.71
32.5	2,405,174	16,808	0.0070	0.9930	82.92
33.5	2,183,084	32,180	0.0147	0.9853	82.34
34.5	2,137,565	18,630	0.0087	0.9913	81.13
35.5	1,862,953	12,150	0.0065	0.9935	80.42
36.5	1,065,935	5,828	0.0055	0.9945	79.89
37.5	1,007,755	7,150	0.0071	0.9929	79.46
38.5	997,709	15,160	0.0152	0.9848	78.89

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2015 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	964,691	651	0.0007	0.9993	77.70
40.5	961,101	51,515	0.0536	0.9464	77.64
41.5	893,141	5,688	0.0064	0.9936	73.48
42.5	825,088	4,001	0.0048	0.9952	73.01
43.5	779,348	21,099	0.0271	0.9729	72.66
44.5	718,071	772	0.0011	0.9989	70.69
45.5	676,843	618	0.0009	0.9991	70.62
46.5	662,280		0.0000	1.0000	70.55
47.5	642,974	762	0.0012	0.9988	70.55
48.5	507,665	614	0.0012	0.9988	70.47
49.5	380,042	2,171	0.0057	0.9943	70.38
50.5	356,425		0.0000	1.0000	69.98
51.5	218,668		0.0000	1.0000	69.98
52.5	158,778	611	0.0038	0.9962	69.98
53.5	156,556		0.0000	1.0000	69.71
54.5	130,088	4,048	0.0311	0.9689	69.71
55.5	95,390		0.0000	1.0000	67.54
56.5	93,474		0.0000	1.0000	67.54
57.5	46,377		0.0000	1.0000	67.54
58.5	41,631		0.0000	1.0000	67.54
59.5	31,958		0.0000	1.0000	67.54
60.5	26,586		0.0000	1.0000	67.54
61.5	3,876		0.0000	1.0000	67.54
62.5	3,876		0.0000	1.0000	67.54
63.5	2,279		0.0000	1.0000	67.54
64.5	2,279		0.0000	1.0000	67.54
65.5	2,279		0.0000	1.0000	67.54
66.5	2,279		0.0000	1.0000	67.54
67.5	2,279		0.0000	1.0000	67.54
68.5	2,279		0.0000	1.0000	67.54
69.5	2,279		0.0000	1.0000	67.54
70.5	2,279		0.0000	1.0000	67.54
71.5	2,279		0.0000	1.0000	67.54
72.5	2,279		0.0000	1.0000	67.54
73.5	2,279		0.0000	1.0000	67.54
74.5	2,279		0.0000	1.0000	67.54
75.5	2,279		0.0000	1.0000	67.54
76.5	2,279		0.0000	1.0000	67.54
77.5	2,279		0.0000	1.0000	67.54
78.5	2,279		0.0000	1.0000	67.54

UGI UTILITIES, INC. - GAS DIVISION

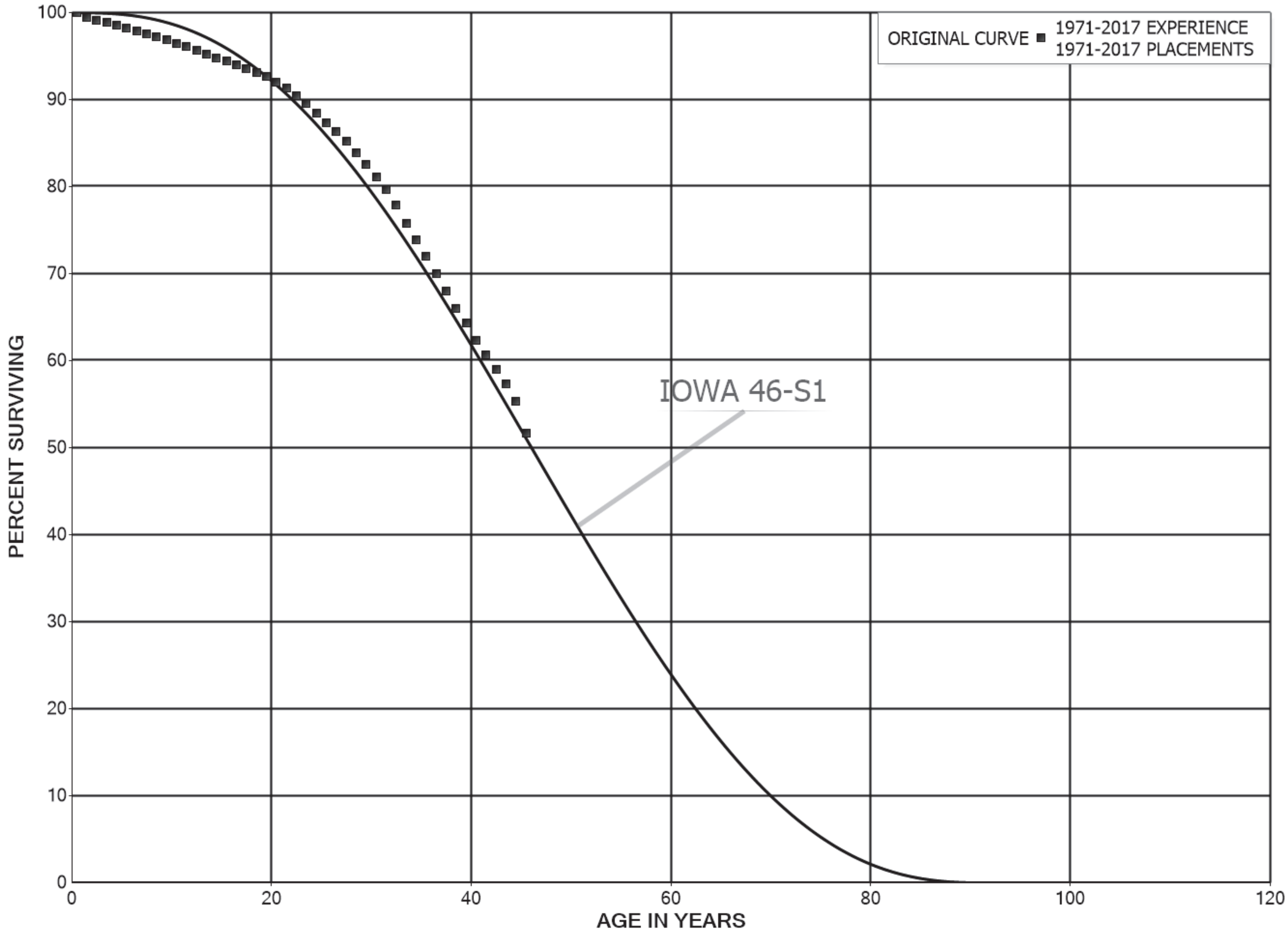
ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1840-2015 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	2,279		0.0000	1.0000	67.54
80.5	2,279		0.0000	1.0000	67.54
81.5	2,279		0.0000	1.0000	67.54
82.5	2,279		0.0000	1.0000	67.54
83.5	2,279		0.0000	1.0000	67.54
84.5	2,279		0.0000	1.0000	67.54
85.5	2,279		0.0000	1.0000	67.54
86.5	2,279		0.0000	1.0000	67.54
87.5	2,279		0.0000	1.0000	67.54
88.5	2,279		0.0000	1.0000	67.54
89.5	2,279		0.0000	1.0000	67.54
90.5	2,279		0.0000	1.0000	67.54
91.5	2,279		0.0000	1.0000	67.54
92.5	2,279		0.0000	1.0000	67.54
93.5	2,279		0.0000	1.0000	67.54
94.5	2,279		0.0000	1.0000	67.54
95.5	2,279		0.0000	1.0000	67.54
96.5	2,279		0.0000	1.0000	67.54
97.5	2,279		0.0000	1.0000	67.54
98.5	2,279		0.0000	1.0000	67.54
99.5	2,279	2,279	1.0000		67.54
100.5					

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 380 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2017 EXPERIENCE BAND 1971-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,011,657,252	627,862	0.0006	0.9994	100.00
0.5	959,147,367	5,562,201	0.0058	0.9942	99.94
1.5	884,777,478	2,532,589	0.0029	0.9971	99.36
2.5	815,151,211	2,357,630	0.0029	0.9971	99.07
3.5	753,376,913	2,011,700	0.0027	0.9973	98.79
4.5	692,817,080	2,256,226	0.0033	0.9967	98.52
5.5	642,110,502	2,274,385	0.0035	0.9965	98.20
6.5	606,124,744	2,036,205	0.0034	0.9966	97.85
7.5	581,825,670	1,971,939	0.0034	0.9966	97.53
8.5	555,844,824	2,281,184	0.0041	0.9959	97.20
9.5	529,909,764	2,058,868	0.0039	0.9961	96.80
10.5	508,571,359	2,049,384	0.0040	0.9960	96.42
11.5	487,693,182	1,969,547	0.0040	0.9960	96.03
12.5	464,747,988	2,071,295	0.0045	0.9955	95.64
13.5	436,405,349	2,010,447	0.0046	0.9954	95.22
14.5	415,836,038	1,782,356	0.0043	0.9957	94.78
15.5	395,502,966	1,817,095	0.0046	0.9954	94.37
16.5	374,712,131	1,803,702	0.0048	0.9952	93.94
17.5	356,332,962	1,694,143	0.0048	0.9952	93.49
18.5	337,583,168	1,723,492	0.0051	0.9949	93.04
19.5	316,868,901	1,950,719	0.0062	0.9938	92.57
20.5	292,913,195	2,427,675	0.0083	0.9917	92.00
21.5	270,342,988	2,639,119	0.0098	0.9902	91.24
22.5	245,704,004	2,400,483	0.0098	0.9902	90.34
23.5	222,976,751	2,624,741	0.0118	0.9882	89.46
24.5	206,682,201	2,541,803	0.0123	0.9877	88.41
25.5	187,866,231	2,184,738	0.0116	0.9884	87.32
26.5	170,036,910	2,287,767	0.0135	0.9865	86.31
27.5	150,031,450	2,307,025	0.0154	0.9846	85.15
28.5	131,634,336	2,045,837	0.0155	0.9845	83.84
29.5	115,999,535	2,075,667	0.0179	0.9821	82.53
30.5	103,231,381	1,881,842	0.0182	0.9818	81.06
31.5	92,478,073	1,971,795	0.0213	0.9787	79.58
32.5	82,596,514	2,230,594	0.0270	0.9730	77.88
33.5	73,514,498	1,847,599	0.0251	0.9749	75.78
34.5	65,518,325	1,673,537	0.0255	0.9745	73.87
35.5	55,732,910	1,607,781	0.0288	0.9712	71.99
36.5	44,881,537	1,257,487	0.0280	0.9720	69.91
37.5	34,013,064	1,031,542	0.0303	0.9697	67.95
38.5	26,697,183	663,957	0.0249	0.9751	65.89

UGI UTILITIES, INC. - GAS DIVISION

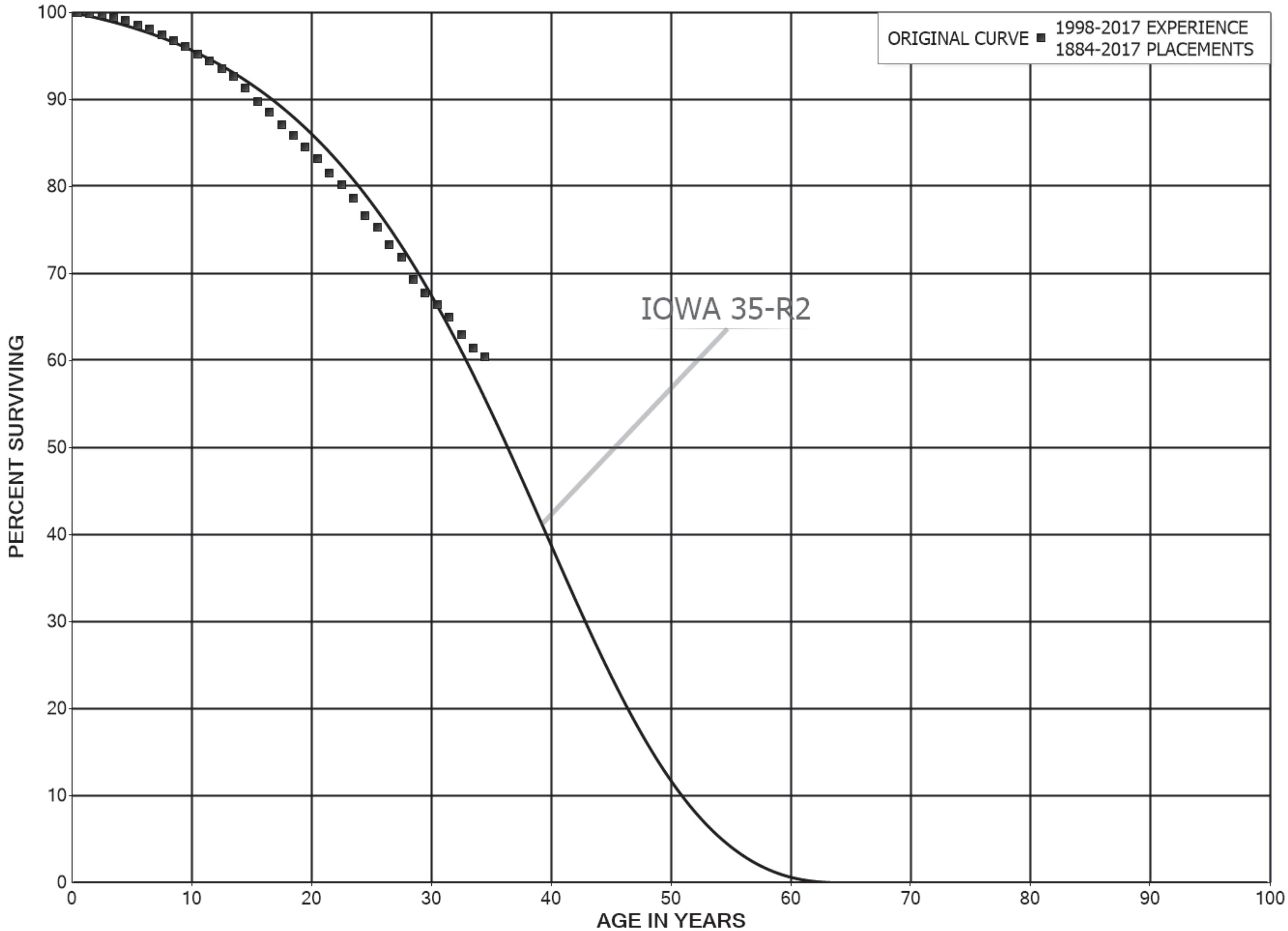
ACCOUNT 380 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1971-2017 EXPERIENCE BAND 1971-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	22,236,529	692,460	0.0311	0.9689	64.25
40.5	17,212,646	440,832	0.0256	0.9744	62.25
41.5	13,946,690	392,152	0.0281	0.9719	60.66
42.5	11,124,018	309,024	0.0278	0.9722	58.95
43.5	7,713,855	267,481	0.0347	0.9653	57.31
44.5	4,425,157	299,648	0.0677	0.9323	55.33
45.5	1,544,627	87,440	0.0566	0.9434	51.58
46.5					48.66

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 381 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1884-2017 EXPERIENCE BAND 1998-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	79,278,414	1,697	0.0000	1.0000	100.00
0.5	74,535,675	136,830	0.0018	0.9982	100.00
1.5	69,719,505	85,555	0.0012	0.9988	99.81
2.5	66,741,372	198,706	0.0030	0.9970	99.69
3.5	63,772,476	227,951	0.0036	0.9964	99.39
4.5	60,982,760	299,416	0.0049	0.9951	99.04
5.5	59,138,572	262,295	0.0044	0.9956	98.55
6.5	56,904,897	428,756	0.0075	0.9925	98.12
7.5	56,438,002	397,536	0.0070	0.9930	97.38
8.5	55,090,812	352,863	0.0064	0.9936	96.69
9.5	52,162,293	471,384	0.0090	0.9910	96.07
10.5	50,819,393	454,031	0.0089	0.9911	95.20
11.5	49,018,517	419,224	0.0086	0.9914	94.35
12.5	47,814,378	497,633	0.0104	0.9896	93.55
13.5	45,204,267	648,540	0.0143	0.9857	92.57
14.5	43,249,428	699,007	0.0162	0.9838	91.24
15.5	41,169,933	579,695	0.0141	0.9859	89.77
16.5	40,927,693	661,117	0.0162	0.9838	88.51
17.5	41,212,551	602,315	0.0146	0.9854	87.08
18.5	39,460,071	588,809	0.0149	0.9851	85.80
19.5	36,669,899	587,817	0.0160	0.9840	84.52
20.5	33,903,463	673,789	0.0199	0.9801	83.17
21.5	31,279,426	535,331	0.0171	0.9829	81.52
22.5	29,266,810	545,817	0.0186	0.9814	80.12
23.5	25,658,150	641,041	0.0250	0.9750	78.63
24.5	23,068,620	413,472	0.0179	0.9821	76.66
25.5	21,056,462	545,839	0.0259	0.9741	75.29
26.5	18,872,278	397,831	0.0211	0.9789	73.34
27.5	17,325,613	616,041	0.0356	0.9644	71.79
28.5	16,367,574	367,203	0.0224	0.9776	69.24
29.5	15,891,424	303,836	0.0191	0.9809	67.68
30.5	15,254,993	330,832	0.0217	0.9783	66.39
31.5	14,645,544	441,552	0.0301	0.9699	64.95
32.5	13,832,631	346,562	0.0251	0.9749	62.99
33.5	13,617,285	230,461	0.0169	0.9831	61.41
34.5	13,539,805	205,417	0.0152	0.9848	60.37
35.5	13,153,579	251,119	0.0191	0.9809	59.46
36.5	11,123,322	252,544	0.0227	0.9773	58.32
37.5	9,123,287	202,039	0.0221	0.9779	57.00
38.5	8,570,336	141,852	0.0166	0.9834	55.74

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1884-2017 EXPERIENCE BAND 1998-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,248,433	151,020	0.0183	0.9817	54.81
40.5	7,998,998	369,447	0.0462	0.9538	53.81
41.5	7,592,508	169,179	0.0223	0.9777	51.33
42.5	7,301,579	221,480	0.0303	0.9697	50.18
43.5	6,899,758	146,237	0.0212	0.9788	48.66
44.5	6,537,214	195,290	0.0299	0.9701	47.63
45.5	6,051,044	176,480	0.0292	0.9708	46.21
46.5	5,480,274	248,303	0.0453	0.9547	44.86
47.5	4,606,014	328,363	0.0713	0.9287	42.83
48.5	3,605,459	276,892	0.0768	0.9232	39.77
49.5	2,801,519	237,329	0.0847	0.9153	36.72
50.5	2,168,500	96,505	0.0445	0.9555	33.61
51.5	1,625,348	119,581	0.0736	0.9264	32.11
52.5	1,133,350	206,100	0.1819	0.8181	29.75
53.5	718,735	115,637	0.1609	0.8391	24.34
54.5	521,149	72,330	0.1388	0.8612	20.42
55.5	395,304	61,893	0.1566	0.8434	17.59
56.5	335,775	48,836	0.1454	0.8546	14.83
57.5	305,335	38,803	0.1271	0.8729	12.68
58.5	276,206	26,668	0.0966	0.9034	11.07
59.5	262,010	32,976	0.1259	0.8741	10.00
60.5	247,586	25,184	0.1017	0.8983	8.74
61.5	225,726	19,912	0.0882	0.9118	7.85
62.5	206,329	16,029	0.0777	0.9223	7.16
63.5	189,521	11,789	0.0622	0.9378	6.60
64.5	171,267	16,612	0.0970	0.9030	6.19
65.5	134,571	22,942	0.1705	0.8295	5.59
66.5	107,344	18,724	0.1744	0.8256	4.64
67.5	85,459	13,759	0.1610	0.8390	3.83
68.5	67,859	12,520	0.1845	0.8155	3.21
69.5	54,130	10,577	0.1954	0.8046	2.62
70.5	40,501	5,353	0.1322	0.8678	2.11
71.5	33,763	4,645	0.1376	0.8624	1.83
72.5	28,004	2,831	0.1011	0.8989	1.58
73.5	24,150	1,989	0.0824	0.9176	1.42
74.5	21,644	1,062	0.0491	0.9509	1.30
75.5	19,200	2,192	0.1142	0.8858	1.24
76.5	13,039	885	0.0679	0.9321	1.10
77.5	9,408	397	0.0422	0.9578	1.02
78.5	6,612	91	0.0138	0.9862	0.98

UGI UTILITIES, INC. - GAS DIVISION

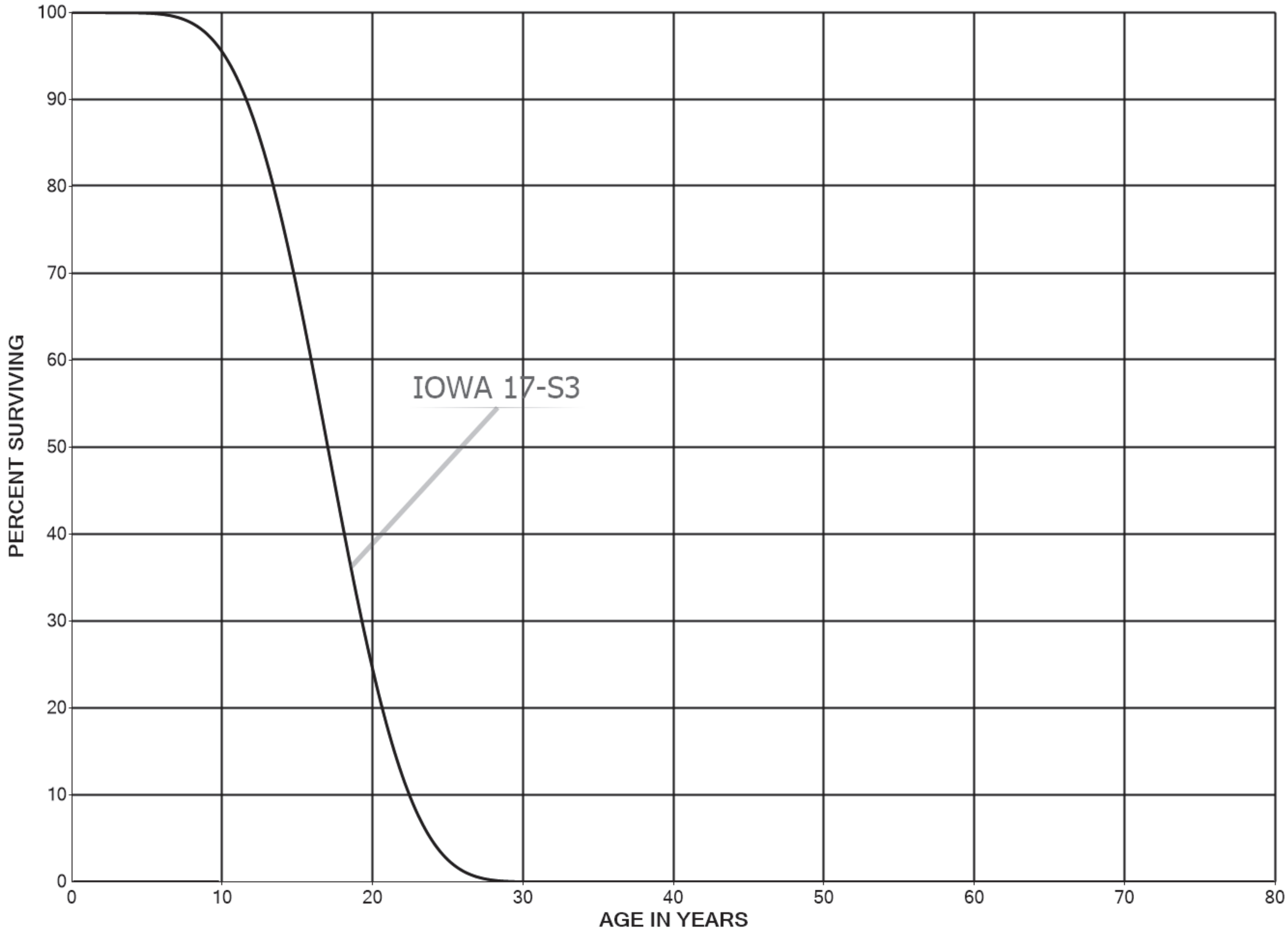
ACCOUNT 381 METERS

ORIGINAL LIFE TABLE, CONT.

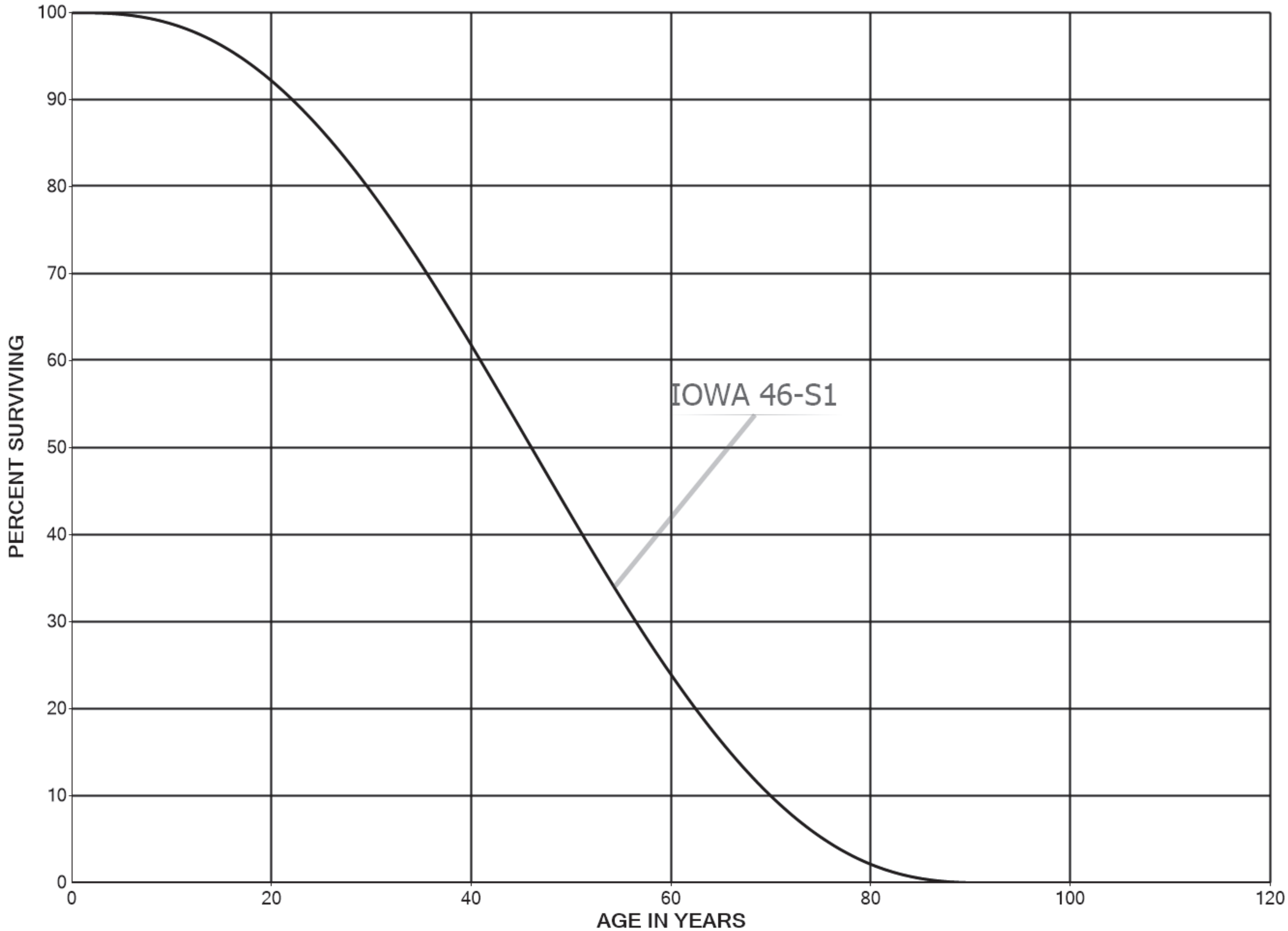
PLACEMENT BAND 1884-2017 EXPERIENCE BAND 1998-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	4,674	200	0.0429	0.9571	0.97
80.5	2,699	83	0.0306	0.9694	0.92
81.5	1,636	47	0.0289	0.9711	0.90
82.5	974	30	0.0307	0.9693	0.87
83.5	737	44	0.0600	0.9400	0.84
84.5	679	43	0.0633	0.9367	0.79
85.5	592	124	0.2086	0.7914	0.74
86.5	466	63	0.1359	0.8641	0.59
87.5	309	26	0.0841	0.9159	0.51
88.5	228	19	0.0824	0.9176	0.46
89.5	223	80	0.3595	0.6405	0.43
90.5	143	125	0.8759	0.1241	0.27
91.5	18	10	0.5719	0.4281	0.03
92.5	8		0.0000	1.0000	0.01
93.5	8	5	0.7154	0.2846	0.01
94.5	6		0.0000	1.0000	0.00
95.5	6		0.0000	1.0000	0.00
96.5	6		0.0000	1.0000	0.00
97.5	35	2	0.0615	0.9385	0.00
98.5	63	4	0.0673	0.9327	0.00
99.5	70		0.0000	1.0000	0.00
100.5	70	1	0.0078	0.9922	0.00
101.5	70	50	0.7116	0.2884	0.00
102.5	20	11	0.5683	0.4317	0.00
103.5	9		0.0000	1.0000	0.00
104.5	9		0.0000	1.0000	0.00
105.5	9	9	1.0000		0.00
106.5					

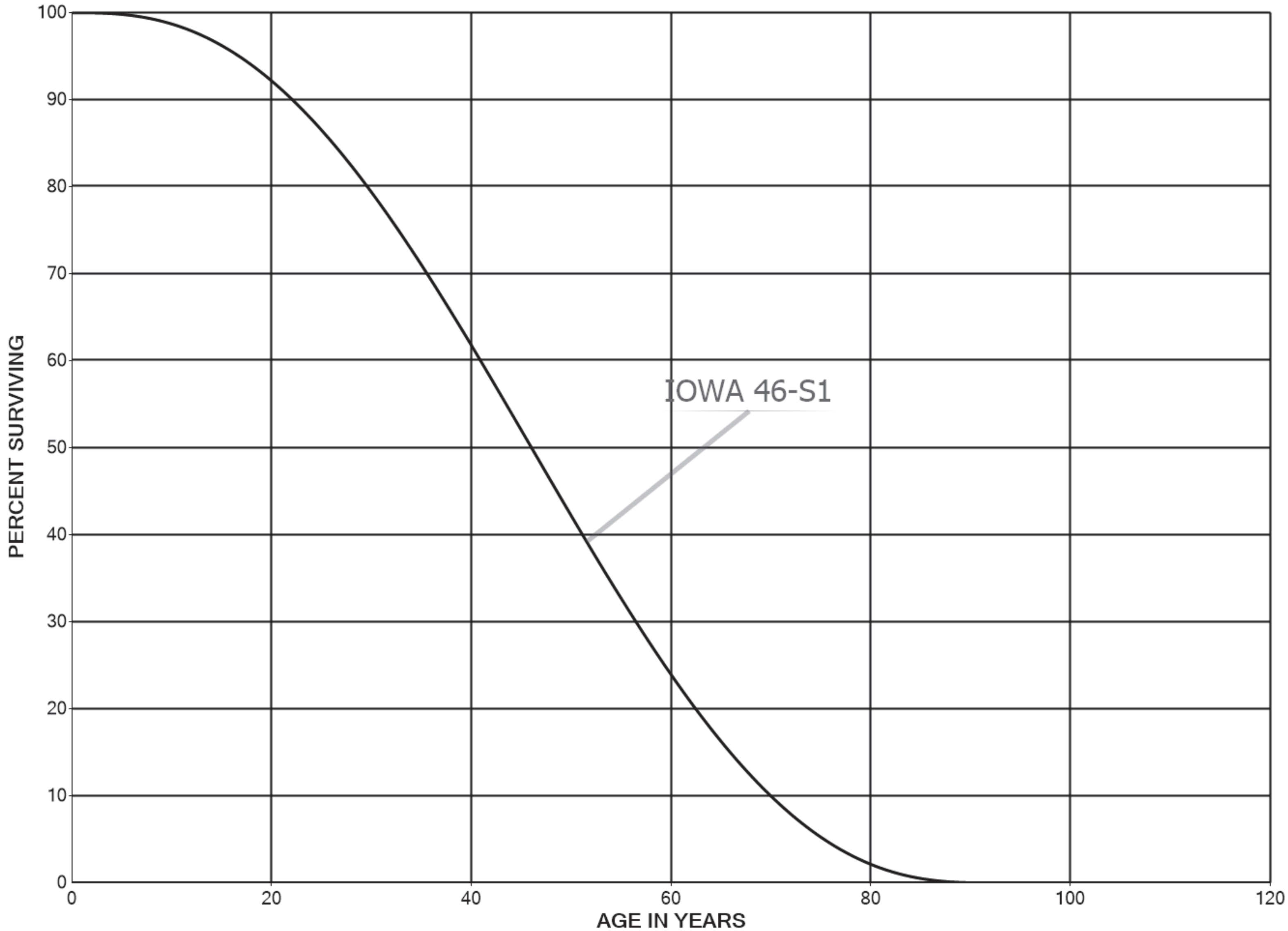
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 381.1 METERS - ERTS
SMOOTH SURVIVOR CURVE



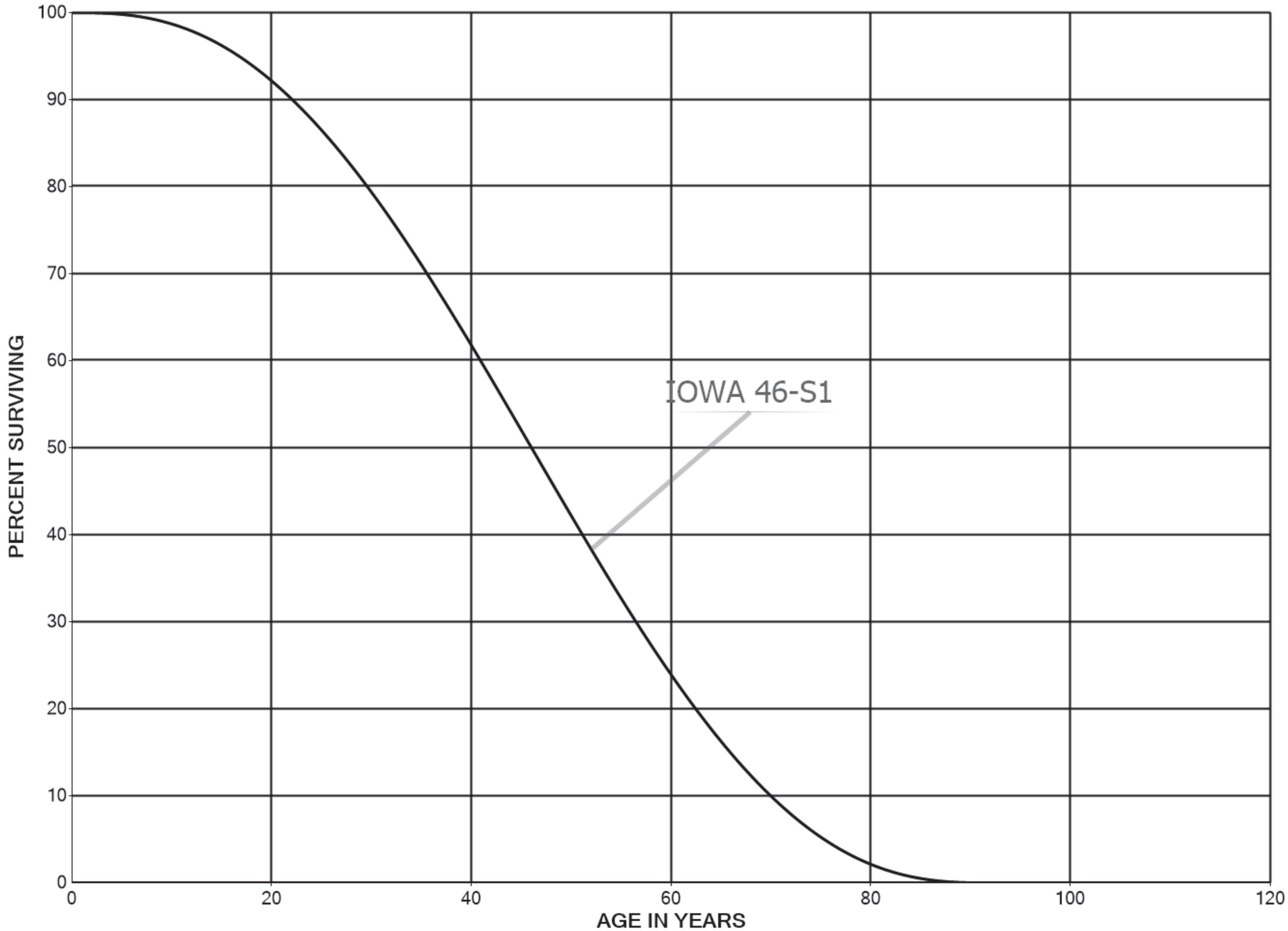
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 382 METER INSTALLATIONS
SMOOTH SURVIVOR CURVE



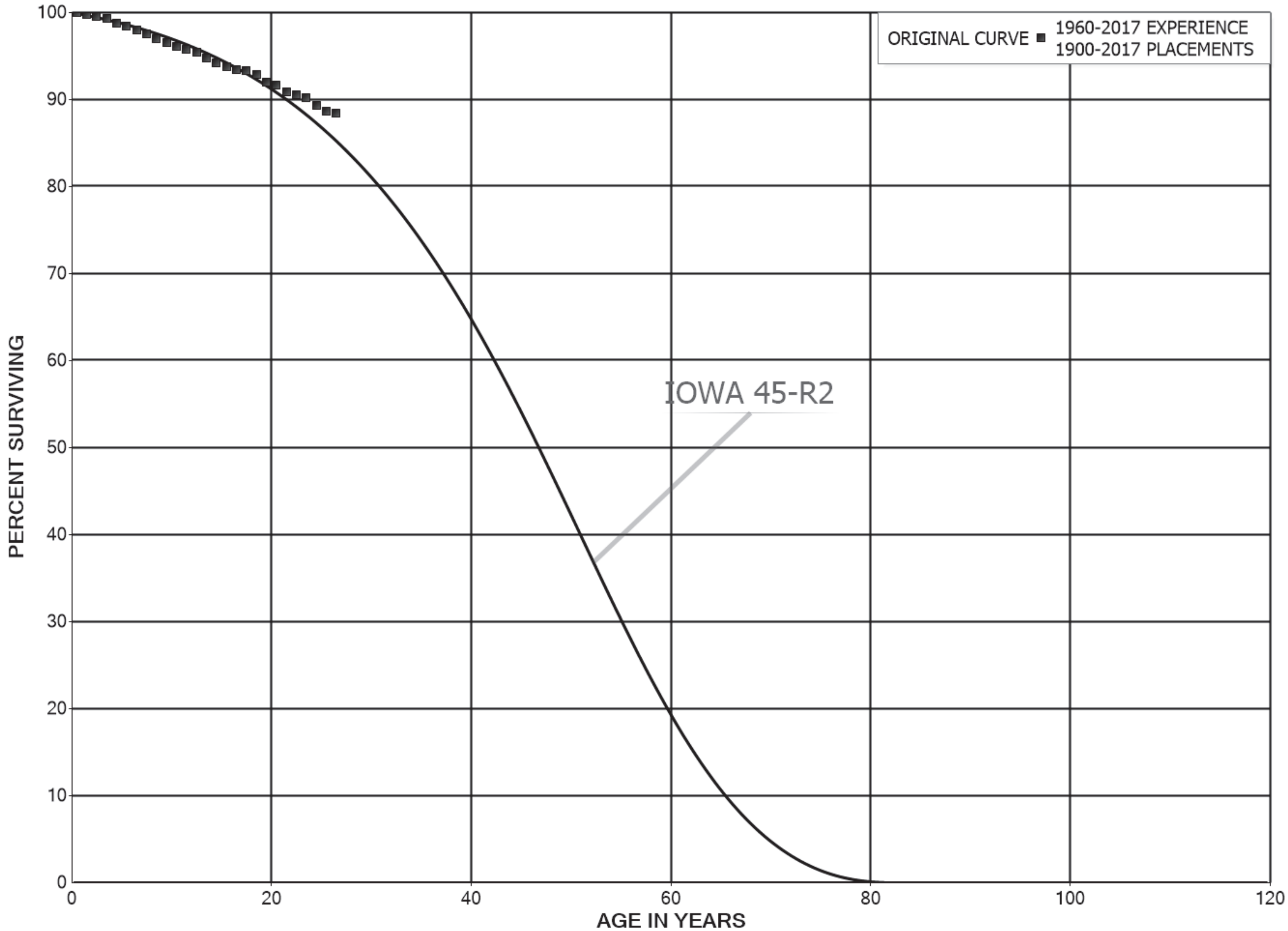
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 383 HOUSE REGULATORS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	35,558,687	37,616	0.0011	0.9989	100.00
0.5	35,142,162	53,488	0.0015	0.9985	99.89
1.5	32,021,469	65,423	0.0020	0.9980	99.74
2.5	28,445,976	69,402	0.0024	0.9976	99.54
3.5	27,763,758	153,145	0.0055	0.9945	99.30
4.5	27,246,422	100,289	0.0037	0.9963	98.75
5.5	26,057,047	130,447	0.0050	0.9950	98.38
6.5	24,007,596	96,554	0.0040	0.9960	97.89
7.5	22,900,258	132,220	0.0058	0.9942	97.50
8.5	22,214,308	94,580	0.0043	0.9957	96.94
9.5	21,310,773	105,426	0.0049	0.9951	96.52
10.5	20,484,524	67,500	0.0033	0.9967	96.04
11.5	19,607,951	78,003	0.0040	0.9960	95.73
12.5	19,026,605	123,373	0.0065	0.9935	95.35
13.5	18,014,326	99,187	0.0055	0.9945	94.73
14.5	16,872,530	76,943	0.0046	0.9954	94.21
15.5	16,164,336	66,893	0.0041	0.9959	93.78
16.5	15,853,268	20,737	0.0013	0.9987	93.39
17.5	15,170,043	68,148	0.0045	0.9955	93.27
18.5	14,096,768	129,263	0.0092	0.9908	92.85
19.5	13,143,392	52,957	0.0040	0.9960	92.00
20.5	12,257,190	100,442	0.0082	0.9918	91.63
21.5	11,241,237	43,392	0.0039	0.9961	90.88
22.5	10,520,357	40,764	0.0039	0.9961	90.53
23.5	9,935,495	98,352	0.0099	0.9901	90.17
24.5	9,481,988	67,587	0.0071	0.9929	89.28
25.5	8,948,086	25,389	0.0028	0.9972	88.65
26.5	8,320,650	26,351	0.0032	0.9968	88.39
27.5	7,826,612	33,951	0.0043	0.9957	88.11
28.5	7,400,342	32,581	0.0044	0.9956	87.73
29.5	6,730,193	11,010	0.0016	0.9984	87.35
30.5	6,369,692	24,910	0.0039	0.9961	87.20
31.5	6,129,561	18,264	0.0030	0.9970	86.86
32.5	5,878,885	31,652	0.0054	0.9946	86.60
33.5	5,657,861	14,480	0.0026	0.9974	86.14
34.5	5,478,732	20,003	0.0037	0.9963	85.92
35.5	5,077,427	24,808	0.0049	0.9951	85.60
36.5	4,448,471	12,818	0.0029	0.9971	85.18
37.5	3,599,808	8,322	0.0023	0.9977	84.94
38.5	3,370,667	14,278	0.0042	0.9958	84.74

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,305,061	29,788	0.0090	0.9910	84.38
40.5	3,249,386	5,406	0.0017	0.9983	83.62
41.5	3,180,474	2,372	0.0007	0.9993	83.48
42.5	3,119,757	9,658	0.0031	0.9969	83.42
43.5	2,999,686	12,179	0.0041	0.9959	83.16
44.5	2,857,703	11,697	0.0041	0.9959	82.83
45.5	2,502,109	8,486	0.0034	0.9966	82.49
46.5	2,198,930	3,654	0.0017	0.9983	82.21
47.5	1,830,518	4,366	0.0024	0.9976	82.07
48.5	1,506,139	5,042	0.0033	0.9967	81.87
49.5	1,148,527	2,441	0.0021	0.9979	81.60
50.5	863,559	1,779	0.0021	0.9979	81.43
51.5	670,827	3,499	0.0052	0.9948	81.26
52.5	476,370	1,636	0.0034	0.9966	80.84
53.5	354,079	3,388	0.0096	0.9904	80.56
54.5	273,073	440	0.0016	0.9984	79.79
55.5	216,591	2,404	0.0111	0.9889	79.66
56.5	185,636	688	0.0037	0.9963	78.77
57.5	114,388	2,539	0.0222	0.9778	78.48
58.5	97,994	9,461	0.0965	0.9035	76.74
59.5	86,149		0.0000	1.0000	69.33
60.5	67,285	97	0.0014	0.9986	69.33
61.5	49,899		0.0000	1.0000	69.23
62.5	48,439		0.0000	1.0000	69.23
63.5	46,282		0.0000	1.0000	69.23
64.5	45,591		0.0000	1.0000	69.23
65.5	44,326	63	0.0014	0.9986	69.23
66.5	44,262		0.0000	1.0000	69.13
67.5	44,175		0.0000	1.0000	69.13
68.5	44,088		0.0000	1.0000	69.13
69.5	44,000		0.0000	1.0000	69.13
70.5	43,810		0.0000	1.0000	69.13
71.5	43,599	1,946	0.0446	0.9554	69.13
72.5	41,456		0.0000	1.0000	66.05
73.5	41,389		0.0000	1.0000	66.05
74.5	40,869		0.0000	1.0000	66.05
75.5	40,737		0.0000	1.0000	66.05
76.5	40,647		0.0000	1.0000	66.05
77.5	40,647		0.0000	1.0000	66.05
78.5	40,557		0.0000	1.0000	66.05

UGI UTILITIES, INC. - GAS DIVISION

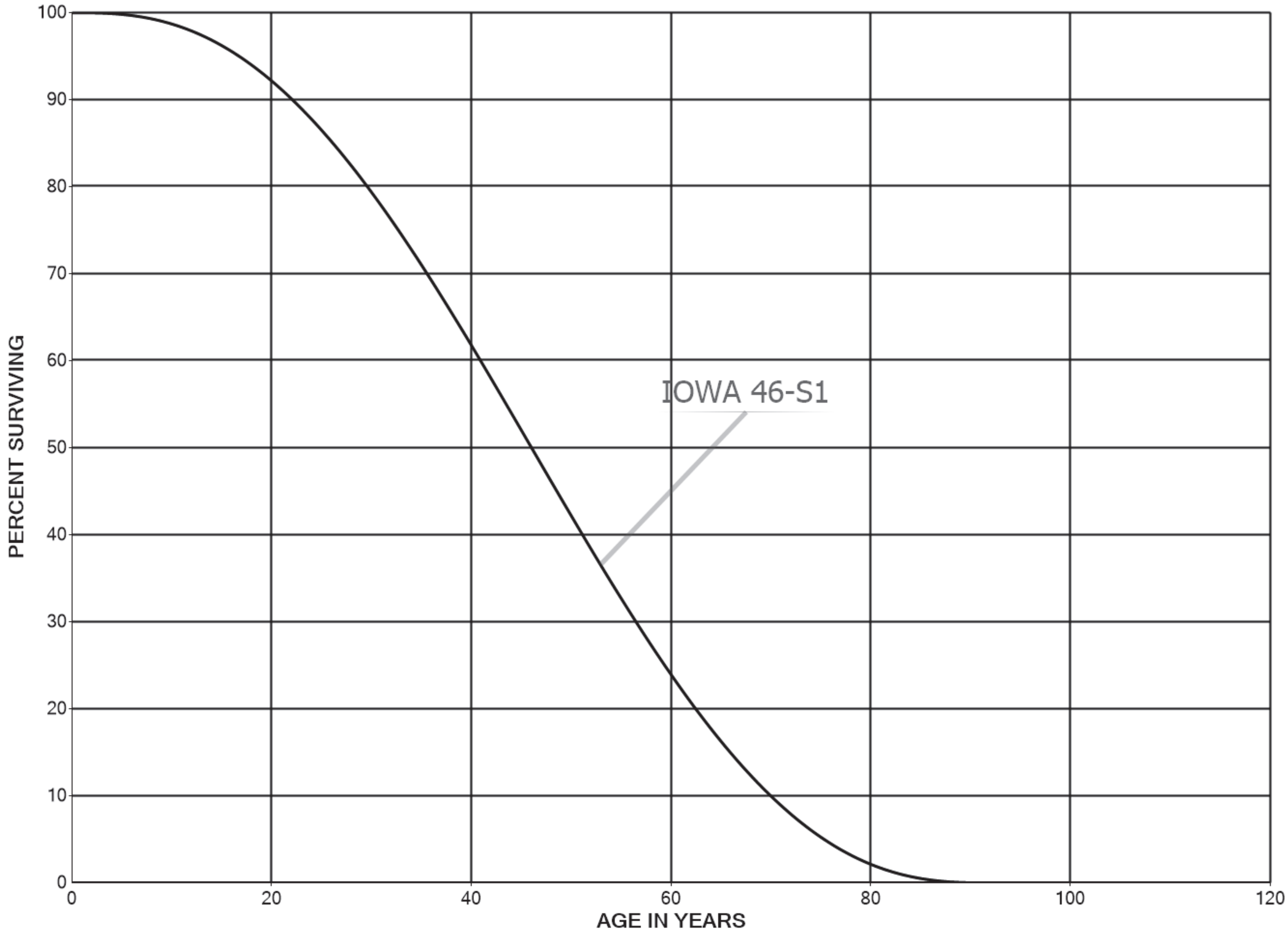
ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

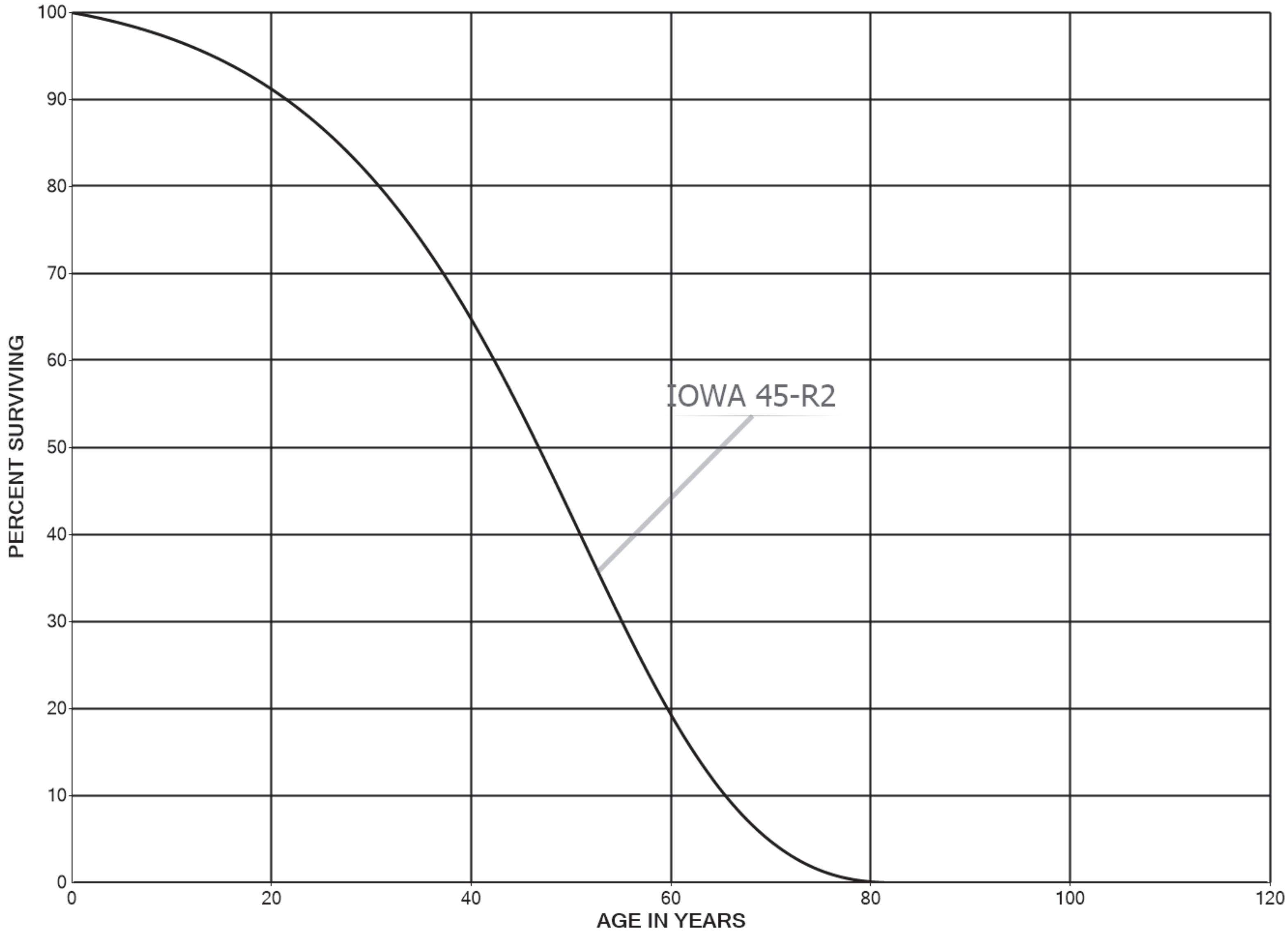
PLACEMENT BAND 1900-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	40,557		0.0000	1.0000	66.05
80.5	40,557		0.0000	1.0000	66.05
81.5	40,557		0.0000	1.0000	66.05
82.5	40,557		0.0000	1.0000	66.05
83.5	40,557		0.0000	1.0000	66.05
84.5	40,557		0.0000	1.0000	66.05
85.5	40,557		0.0000	1.0000	66.05
86.5	40,557		0.0000	1.0000	66.05
87.5	40,557		0.0000	1.0000	66.05
88.5	40,557		0.0000	1.0000	66.05
89.5	40,557		0.0000	1.0000	66.05
90.5	40,557		0.0000	1.0000	66.05
91.5	40,557		0.0000	1.0000	66.05
92.5	40,557		0.0000	1.0000	66.05
93.5	40,557		0.0000	1.0000	66.05
94.5	40,557		0.0000	1.0000	66.05
95.5	40,557		0.0000	1.0000	66.05
96.5	40,557		0.0000	1.0000	66.05
97.5	40,557		0.0000	1.0000	66.05
98.5	40,557		0.0000	1.0000	66.05
99.5	40,557	37,213	0.9176	0.0824	66.05
100.5	3,344		0.0000	1.0000	5.45
101.5	3,344		0.0000	1.0000	5.45
102.5	3,344		0.0000	1.0000	5.45
103.5	3,344		0.0000	1.0000	5.45
104.5	3,344		0.0000	1.0000	5.45
105.5	3,344		0.0000	1.0000	5.45
106.5	3,344		0.0000	1.0000	5.45
107.5	3,344		0.0000	1.0000	5.45
108.5	3,344		0.0000	1.0000	5.45
109.5	3,344		0.0000	1.0000	5.45
110.5	3,344		0.0000	1.0000	5.45
111.5	3,344	3,344	1.0000		5.45
112.5					

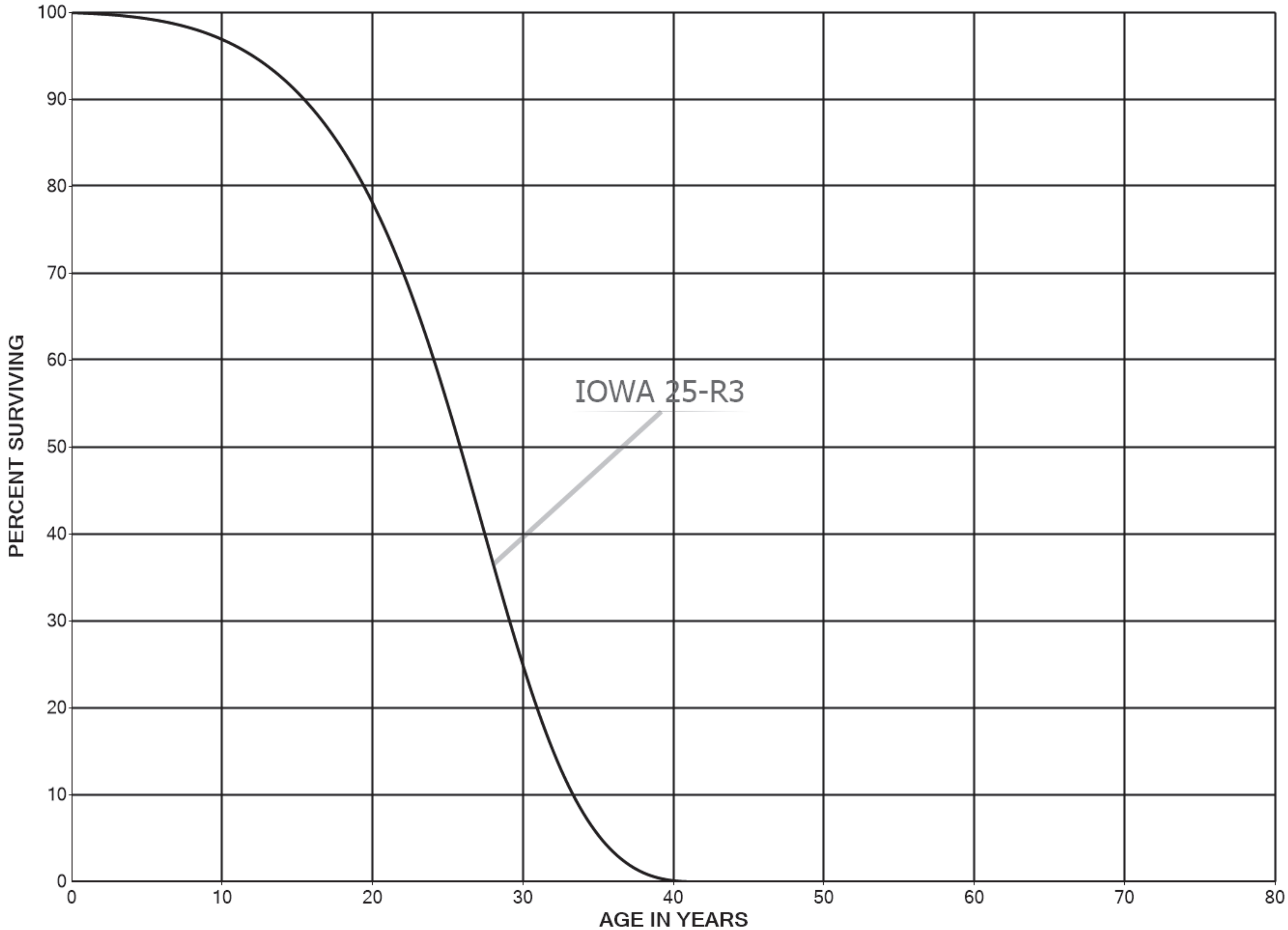
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 386 OTHER PROPERTY ON CUSTOMERS PREMISES
SMOOTH SURVIVOR CURVE



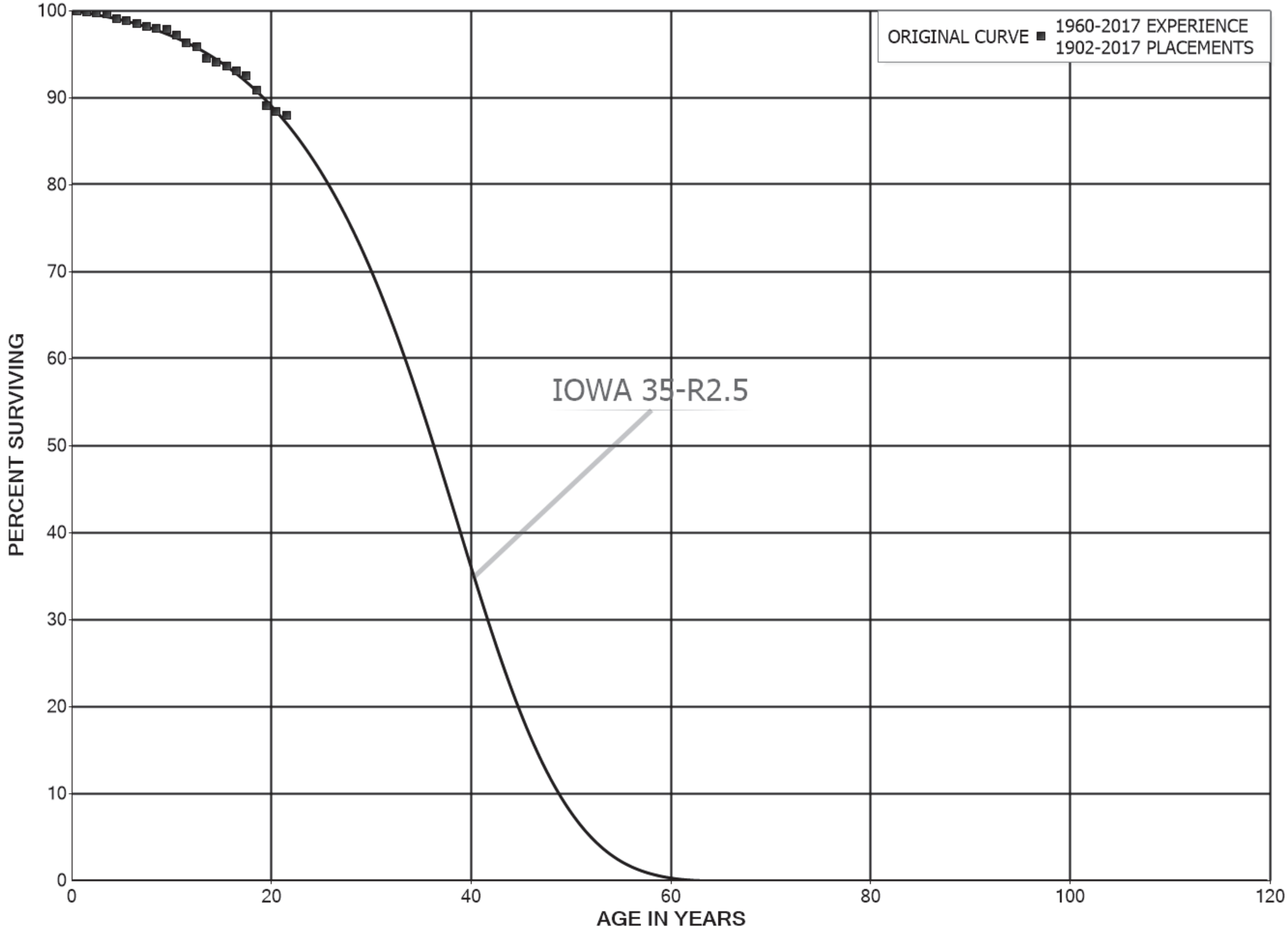
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 387 OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1902-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,261,826	1,797	0.0004	0.9996	100.00
0.5	4,003,247	4,823	0.0012	0.9988	99.96
1.5	3,900,733	5,904	0.0015	0.9985	99.84
2.5	3,889,342	3,661	0.0009	0.9991	99.69
3.5	3,905,528	22,220	0.0057	0.9943	99.59
4.5	3,841,226	7,215	0.0019	0.9981	99.03
5.5	3,846,884	11,817	0.0031	0.9969	98.84
6.5	3,819,885	14,195	0.0037	0.9963	98.54
7.5	3,827,395	9,657	0.0025	0.9975	98.17
8.5	3,792,912	5,121	0.0014	0.9986	97.92
9.5	3,636,407	23,770	0.0065	0.9935	97.79
10.5	3,576,840	33,413	0.0093	0.9907	97.15
11.5	3,440,283	13,431	0.0039	0.9961	96.24
12.5	3,355,360	46,785	0.0139	0.9861	95.87
13.5	3,185,092	17,544	0.0055	0.9945	94.53
14.5	2,944,695	12,242	0.0042	0.9958	94.01
15.5	2,892,885	17,887	0.0062	0.9938	93.62
16.5	2,771,375	16,349	0.0059	0.9941	93.04
17.5	2,530,708	45,932	0.0181	0.9819	92.49
18.5	2,293,637	44,665	0.0195	0.9805	90.81
19.5	1,891,247	13,736	0.0073	0.9927	89.04
20.5	1,792,747	8,224	0.0046	0.9954	88.40
21.5	1,657,593	16,888	0.0102	0.9898	87.99
22.5	1,366,343	10,549	0.0077	0.9923	87.10
23.5	1,227,537	12,959	0.0106	0.9894	86.42
24.5	1,147,207	11,245	0.0098	0.9902	85.51
25.5	1,054,778	5,396	0.0051	0.9949	84.67
26.5	974,808	16,718	0.0171	0.9829	84.24
27.5	853,416	22,644	0.0265	0.9735	82.80
28.5	742,418	10,876	0.0146	0.9854	80.60
29.5	660,239	8,557	0.0130	0.9870	79.42
30.5	591,936	7,005	0.0118	0.9882	78.39
31.5	525,085	4,887	0.0093	0.9907	77.46
32.5	479,349	5,491	0.0115	0.9885	76.74
33.5	412,706	6,950	0.0168	0.9832	75.86
34.5	380,902	8,595	0.0226	0.9774	74.58
35.5	343,544	9,163	0.0267	0.9733	72.90
36.5	322,486	3,020	0.0094	0.9906	70.96
37.5	306,343	5,818	0.0190	0.9810	70.29
38.5	283,957	2,078	0.0073	0.9927	68.96

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	278,262	5,093	0.0183	0.9817	68.45
40.5	262,503	1,812	0.0069	0.9931	67.20
41.5	232,518	1,844	0.0079	0.9921	66.73
42.5	221,328	1,514	0.0068	0.9932	66.21
43.5	213,948	5,625	0.0263	0.9737	65.75
44.5	210,498	725	0.0034	0.9966	64.02
45.5	202,398	4,885	0.0241	0.9759	63.80
46.5	179,046	9,449	0.0528	0.9472	62.26
47.5	196,400	409	0.0021	0.9979	58.98
48.5	190,995	744	0.0039	0.9961	58.86
49.5	181,215	202	0.0011	0.9989	58.63
50.5	169,234	373	0.0022	0.9978	58.56
51.5	179,376	2,683	0.0150	0.9850	58.43
52.5	174,004	1,586	0.0091	0.9909	57.56
53.5	167,617	902	0.0054	0.9946	57.03
54.5	164,197	3,721	0.0227	0.9773	56.73
55.5	157,283	222	0.0014	0.9986	55.44
56.5	153,002	1,774	0.0116	0.9884	55.36
57.5	151,458	510	0.0034	0.9966	54.72
58.5	131,605	3,025	0.0230	0.9770	54.54
59.5	123,948	19,627	0.1583	0.8417	53.28
60.5	101,672	94	0.0009	0.9991	44.85
61.5	93,073	559	0.0060	0.9940	44.80
62.5	88,436	468	0.0053	0.9947	44.53
63.5	81,583	2,539	0.0311	0.9689	44.30
64.5	48,492	355	0.0073	0.9927	42.92
65.5	47,011	59	0.0013	0.9987	42.61
66.5	45,183		0.0000	1.0000	42.55
67.5	36,696	2,899	0.0790	0.9210	42.55
68.5	11,611	231	0.0199	0.9801	39.19
69.5	11,380	192	0.0168	0.9832	38.41
70.5	10,504	3,071	0.2924	0.7076	37.76
71.5	7,325	83	0.0114	0.9886	26.72
72.5	7,242		0.0000	1.0000	26.42
73.5	7,242		0.0000	1.0000	26.42
74.5	7,242		0.0000	1.0000	26.42
75.5	7,242		0.0000	1.0000	26.42
76.5	15,989		0.0000	1.0000	26.42
77.5	15,989		0.0000	1.0000	26.42
78.5	16,017		0.0000	1.0000	26.42

UGI UTILITIES, INC. - GAS DIVISION

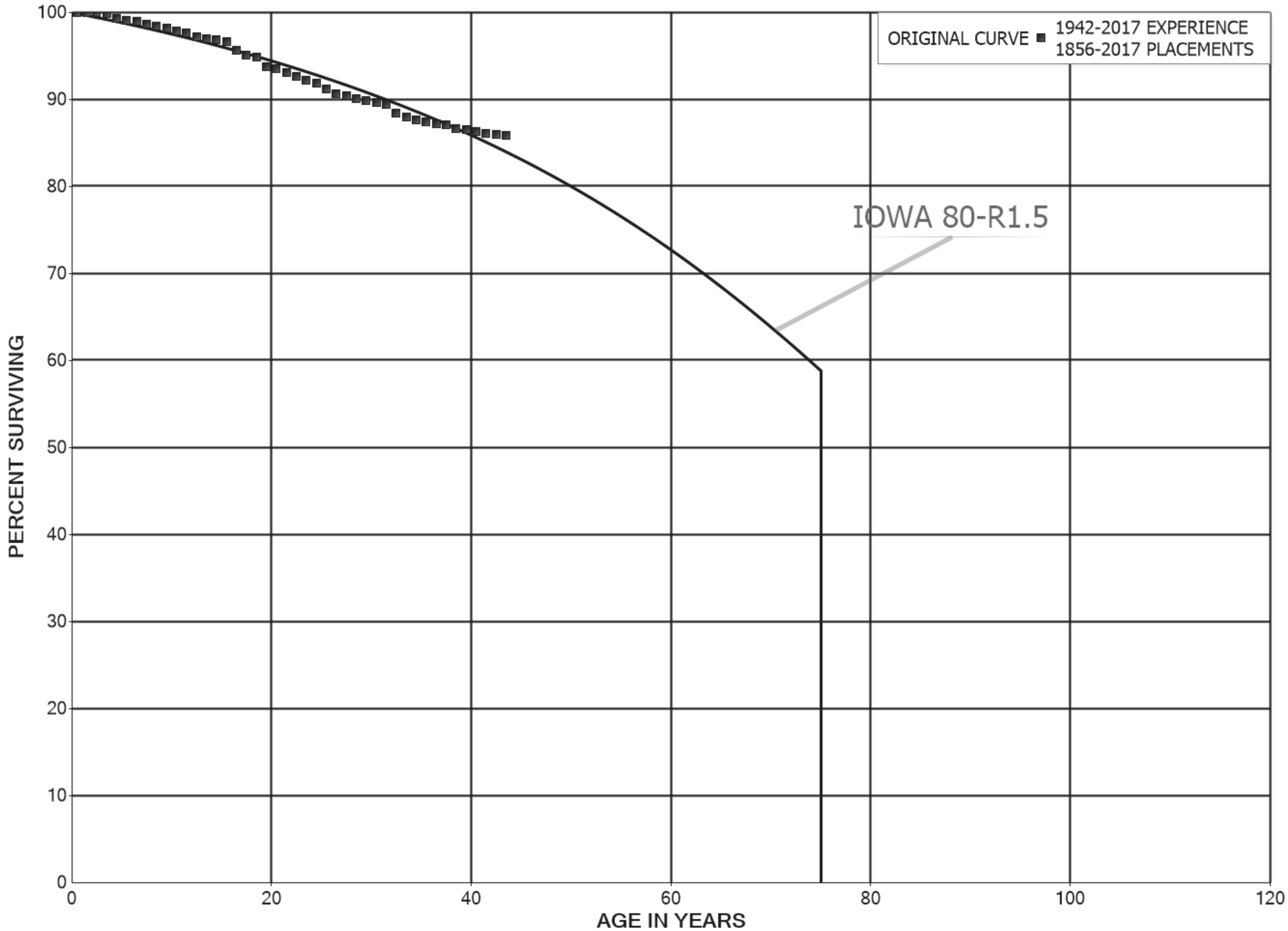
ACCOUNT 387 OTHER EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2017 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	15,947	2,002	0.1255	0.8745	26.42
80.5	13,243	114	0.0086	0.9914	23.10
81.5	13,215	12	0.0009	0.9991	22.90
82.5	12,863		0.0000	1.0000	22.88
83.5	12,863	545	0.0424	0.9576	22.88
84.5	12,318	343	0.0278	0.9722	21.91
85.5	11,795		0.0000	1.0000	21.30
86.5	10,933		0.0000	1.0000	21.30
87.5	10,357		0.0000	1.0000	21.30
88.5	9,955		0.0000	1.0000	21.30
89.5	9,923		0.0000	1.0000	21.30
90.5	9,657		0.0000	1.0000	21.30
91.5	9,649		0.0000	1.0000	21.30
92.5	9,649		0.0000	1.0000	21.30
93.5	519		0.0000	1.0000	21.30
94.5	519		0.0000	1.0000	21.30
95.5	377		0.0000	1.0000	21.30
96.5	377		0.0000	1.0000	21.30
97.5	312		0.0000	1.0000	21.30
98.5	0		0.0000	1.0000	21.30
99.5	0		0.0000	1.0000	21.30
100.5	0		0.0000	1.0000	21.30
101.5	0		0.0000	1.0000	21.30
102.5	0		0.0000	1.0000	21.30
103.5					21.30

UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1856-2017 EXPERIENCE BAND 1942-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	70,935,491	4,309	0.0001	0.9999	100.00
0.5	69,915,967	3,390	0.0000	1.0000	99.99
1.5	66,957,336	39,220	0.0006	0.9994	99.99
2.5	65,041,633	59,282	0.0009	0.9991	99.93
3.5	62,614,939	360,162	0.0058	0.9942	99.84
4.5	61,766,521	139,682	0.0023	0.9977	99.27
5.5	60,167,394	85,471	0.0014	0.9986	99.04
6.5	59,142,373	198,971	0.0034	0.9966	98.90
7.5	58,111,096	85,163	0.0015	0.9985	98.57
8.5	52,414,231	144,738	0.0028	0.9972	98.42
9.5	50,859,546	184,723	0.0036	0.9964	98.15
10.5	48,627,988	95,710	0.0020	0.9980	97.79
11.5	47,788,834	235,988	0.0049	0.9951	97.60
12.5	46,797,740	63,663	0.0014	0.9986	97.12
13.5	44,551,747	69,904	0.0016	0.9984	96.99
14.5	42,974,762	84,959	0.0020	0.9980	96.84
15.5	38,310,770	428,894	0.0112	0.9888	96.64
16.5	36,391,447	186,065	0.0051	0.9949	95.56
17.5	31,421,173	67,965	0.0022	0.9978	95.07
18.5	30,379,881	380,803	0.0125	0.9875	94.87
19.5	29,479,984	59,330	0.0020	0.9980	93.68
20.5	24,585,395	116,620	0.0047	0.9953	93.49
21.5	23,196,130	110,637	0.0048	0.9952	93.05
22.5	22,347,076	106,417	0.0048	0.9952	92.60
23.5	20,068,944	63,402	0.0032	0.9968	92.16
24.5	18,922,927	139,062	0.0073	0.9927	91.87
25.5	15,455,839	92,447	0.0060	0.9940	91.20
26.5	15,208,042	43,902	0.0029	0.9971	90.65
27.5	13,838,049	51,724	0.0037	0.9963	90.39
28.5	12,544,358	34,243	0.0027	0.9973	90.05
29.5	12,049,656	19,512	0.0016	0.9984	89.81
30.5	11,634,754	30,315	0.0026	0.9974	89.66
31.5	11,204,892	130,560	0.0117	0.9883	89.43
32.5	10,915,584	57,079	0.0052	0.9948	88.38
33.5	10,341,064	30,604	0.0030	0.9970	87.92
34.5	10,256,156	30,760	0.0030	0.9970	87.66
35.5	10,130,658	25,798	0.0025	0.9975	87.40
36.5	9,919,280	14,326	0.0014	0.9986	87.18
37.5	9,396,307	49,721	0.0053	0.9947	87.05
38.5	9,106,600	10,843	0.0012	0.9988	86.59

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-2017 EXPERIENCE BAND 1942-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,981,652	21,197	0.0024	0.9976	86.49
40.5	8,608,504	26,261	0.0031	0.9969	86.28
41.5	8,046,898	10,385	0.0013	0.9987	86.02
42.5	7,818,984	5,231	0.0007	0.9993	85.91
43.5	6,556,400	1,906	0.0003	0.9997	85.85
44.5	6,466,007	31,690	0.0049	0.9951	85.83
45.5	6,427,669	40,359	0.0063	0.9937	85.41
46.5	6,003,299	9,606	0.0016	0.9984	84.87
47.5	5,955,919	1,520	0.0003	0.9997	84.73
48.5	5,918,536	3,133	0.0005	0.9995	84.71
49.5	5,858,999	2,065	0.0004	0.9996	84.67
50.5	5,805,274	4,178	0.0007	0.9993	84.64
51.5	5,513,813	13,579	0.0025	0.9975	84.58
52.5	3,906,024	5,710	0.0015	0.9985	84.37
53.5	3,883,274	16,288	0.0042	0.9958	84.24
54.5	3,761,281	811	0.0002	0.9998	83.89
55.5	3,565,281	863	0.0002	0.9998	83.87
56.5	2,909,749	3,727	0.0013	0.9987	83.85
57.5	2,762,219	3,301	0.0012	0.9988	83.75
58.5	2,726,563	5,100	0.0019	0.9981	83.65
59.5	2,700,596	8,734	0.0032	0.9968	83.49
60.5	2,714,970		0.0000	1.0000	83.22
61.5	2,698,653	18,846	0.0070	0.9930	83.22
62.5	1,835,725	2,394	0.0013	0.9987	82.64
63.5	1,475,131	177	0.0001	0.9999	82.53
64.5	1,419,201	15,600	0.0110	0.9890	82.52
65.5	1,383,054	207	0.0001	0.9999	81.61
66.5	1,334,253	188	0.0001	0.9999	81.60
67.5	1,268,246	408	0.0003	0.9997	81.59
68.5	1,256,444	6,541	0.0052	0.9948	81.56
69.5	1,250,517	1,215	0.0010	0.9990	81.14
70.5	1,243,611	15	0.0000	1.0000	81.06
71.5	1,241,875	5,681	0.0046	0.9954	81.06
72.5	1,221,771	9,883	0.0081	0.9919	80.69
73.5	702,908	2,283	0.0032	0.9968	80.03
74.5	699,918	522	0.0007	0.9993	79.77
75.5	699,396	27,870	0.0398	0.9602	79.72
76.5	678,807	7,789	0.0115	0.9885	76.54
77.5	659,986	1,000	0.0015	0.9985	75.66
78.5	658,242	123	0.0002	0.9998	75.55

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1856-2017 EXPERIENCE BAND 1942-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	474,718	200	0.0004	0.9996	75.53
80.5	471,640		0.0000	1.0000	75.50
81.5	467,432	1,401	0.0030	0.9970	75.50
82.5	460,519	480	0.0010	0.9990	75.27
83.5	378,464	5,349	0.0141	0.9859	75.20
84.5	361,901	2	0.0000	1.0000	74.13
85.5	359,188		0.0000	1.0000	74.13
86.5	319,250	7,373	0.0231	0.9769	74.13
87.5	260,477	8,071	0.0310	0.9690	72.42
88.5	245,005		0.0000	1.0000	70.18
89.5	151,496		0.0000	1.0000	70.18
90.5	152,208		0.0000	1.0000	70.18
91.5	147,180	11,745	0.0798	0.9202	70.18
92.5	135,435	189	0.0014	0.9986	64.58
93.5	130,581	1,500	0.0115	0.9885	64.49
94.5	129,535		0.0000	1.0000	63.75
95.5	122,993		0.0000	1.0000	63.75
96.5	122,455		0.0000	1.0000	63.75
97.5	119,606		0.0000	1.0000	63.75
98.5	119,606		0.0000	1.0000	63.75
99.5	112,116	200	0.0018	0.9982	63.75
100.5	107,901		0.0000	1.0000	63.63
101.5	105,606		0.0000	1.0000	63.63
102.5	82,295	561	0.0068	0.9932	63.63
103.5	77,143	100	0.0013	0.9987	63.20
104.5	77,043		0.0000	1.0000	63.12
105.5	74,759		0.0000	1.0000	63.12
106.5	74,496		0.0000	1.0000	63.12
107.5	71,429		0.0000	1.0000	63.12
108.5	70,952		0.0000	1.0000	63.12
109.5	69,952		0.0000	1.0000	63.12
110.5	68,459		0.0000	1.0000	63.12
111.5	68,167		0.0000	1.0000	63.12
112.5	62,005		0.0000	1.0000	63.12
113.5	62,005		0.0000	1.0000	63.12
114.5	62,005	2,723	0.0439	0.9561	63.12
115.5	59,282		0.0000	1.0000	60.34
116.5	50,484		0.0000	1.0000	60.34
117.5	50,484		0.0000	1.0000	60.34
118.5	50,484		0.0000	1.0000	60.34

UGI UTILITIES, INC. - GAS DIVISION

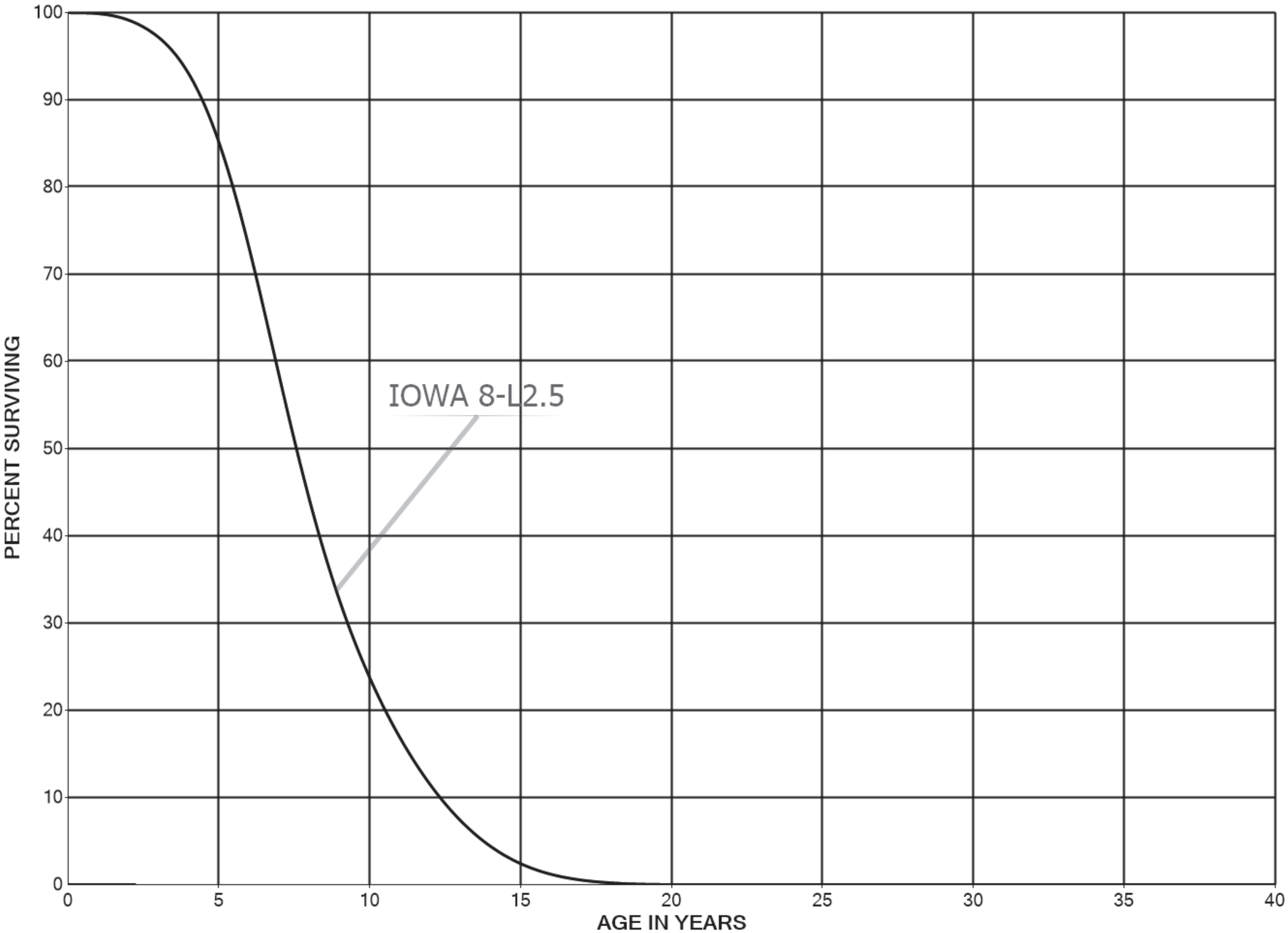
ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

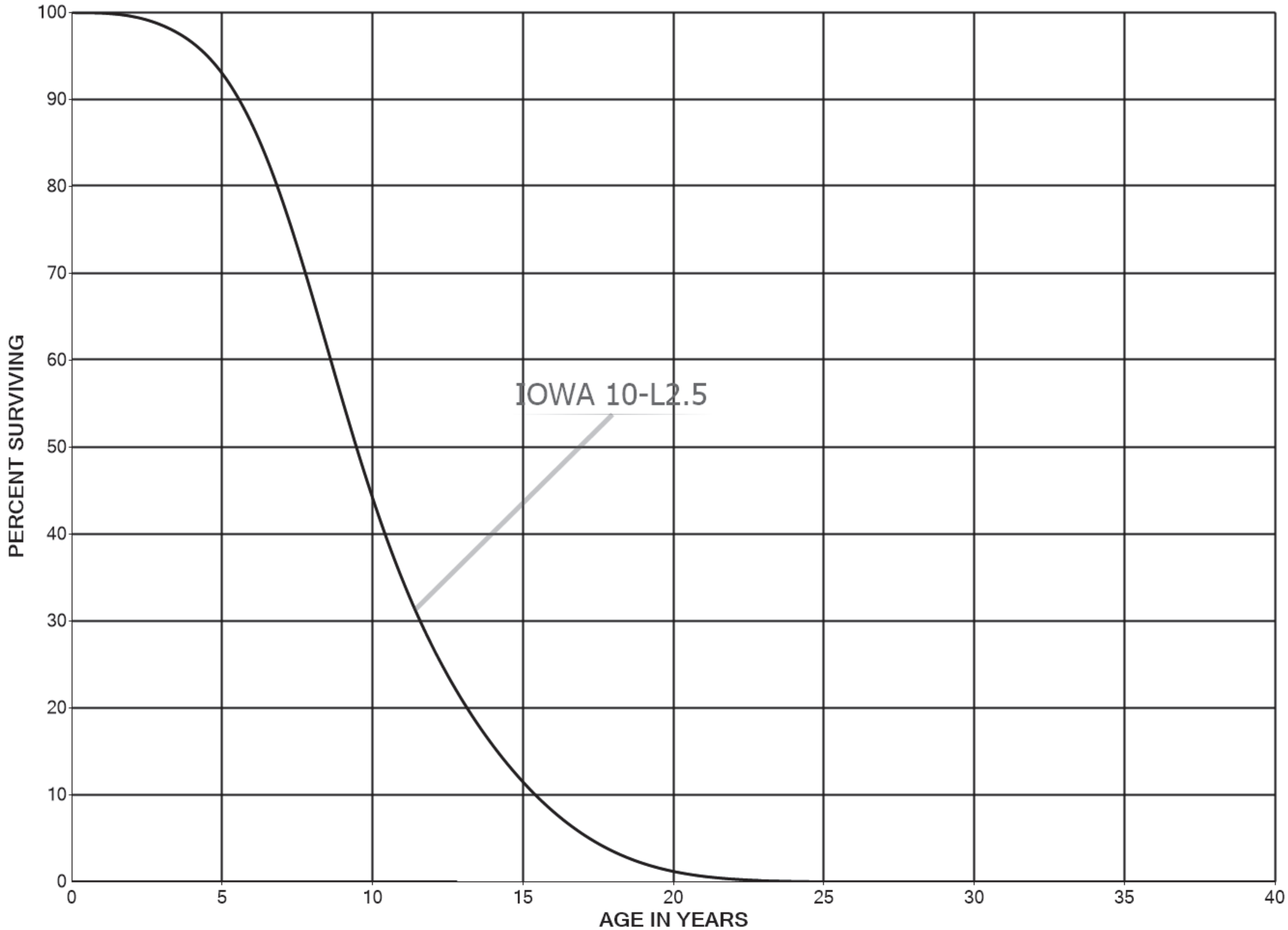
PLACEMENT BAND 1856-2017 EXPERIENCE BAND 1942-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	50,484	18,731	0.3710	0.6290	60.34
120.5	31,753		0.0000	1.0000	37.96
121.5	31,753		0.0000	1.0000	37.96
122.5	31,753		0.0000	1.0000	37.96
123.5	31,753		0.0000	1.0000	37.96
124.5	31,753		0.0000	1.0000	37.96
125.5	31,753		0.0000	1.0000	37.96
126.5	26,717		0.0000	1.0000	37.96
127.5	26,717		0.0000	1.0000	37.96
128.5	26,717		0.0000	1.0000	37.96
129.5	26,717		0.0000	1.0000	37.96
130.5	26,717		0.0000	1.0000	37.96
131.5	26,717		0.0000	1.0000	37.96
132.5	26,717		0.0000	1.0000	37.96
133.5	26,502		0.0000	1.0000	37.96
134.5	17,841		0.0000	1.0000	37.96
135.5	17,841		0.0000	1.0000	37.96
136.5	17,841		0.0000	1.0000	37.96
137.5	17,841		0.0000	1.0000	37.96
138.5	17,841		0.0000	1.0000	37.96
139.5	17,841		0.0000	1.0000	37.96
140.5	7,506		0.0000	1.0000	37.96
141.5	7,506		0.0000	1.0000	37.96
142.5	7,506		0.0000	1.0000	37.96
143.5	2,385		0.0000	1.0000	37.96
144.5	2,385		0.0000	1.0000	37.96
145.5					37.96

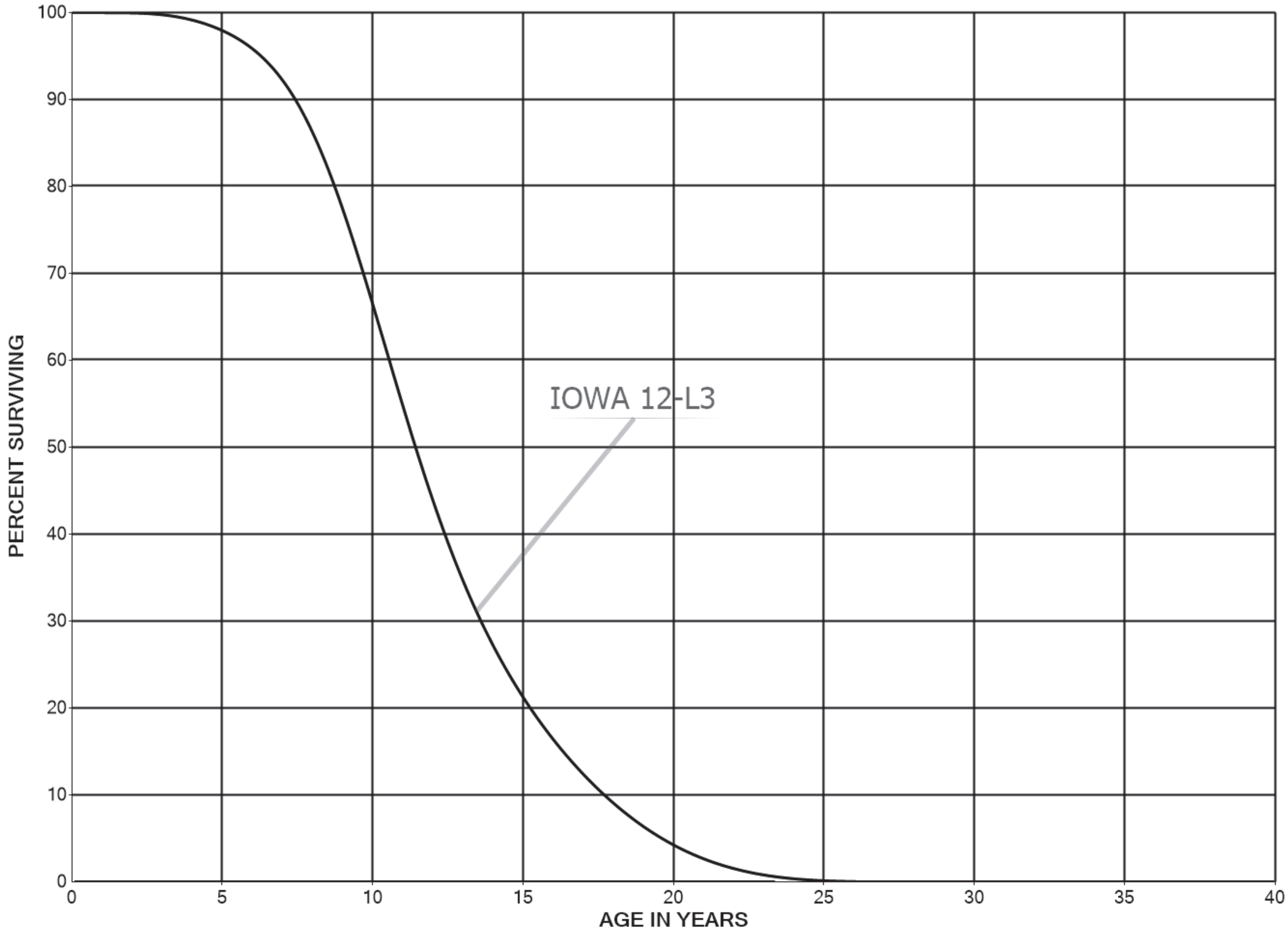
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S
SMOOTH SURVIVOR CURVE



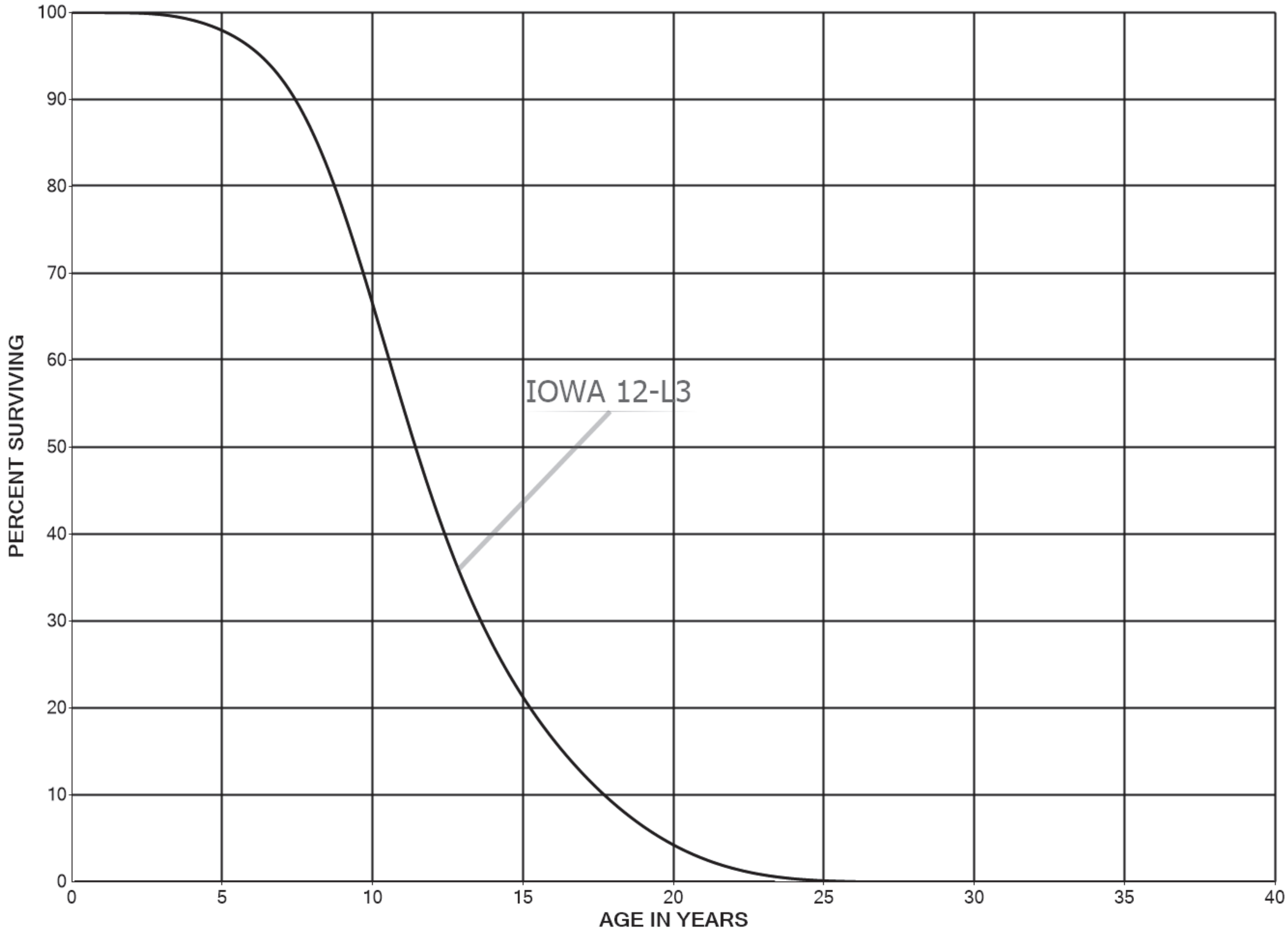
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS
SMOOTH SURVIVOR CURVE



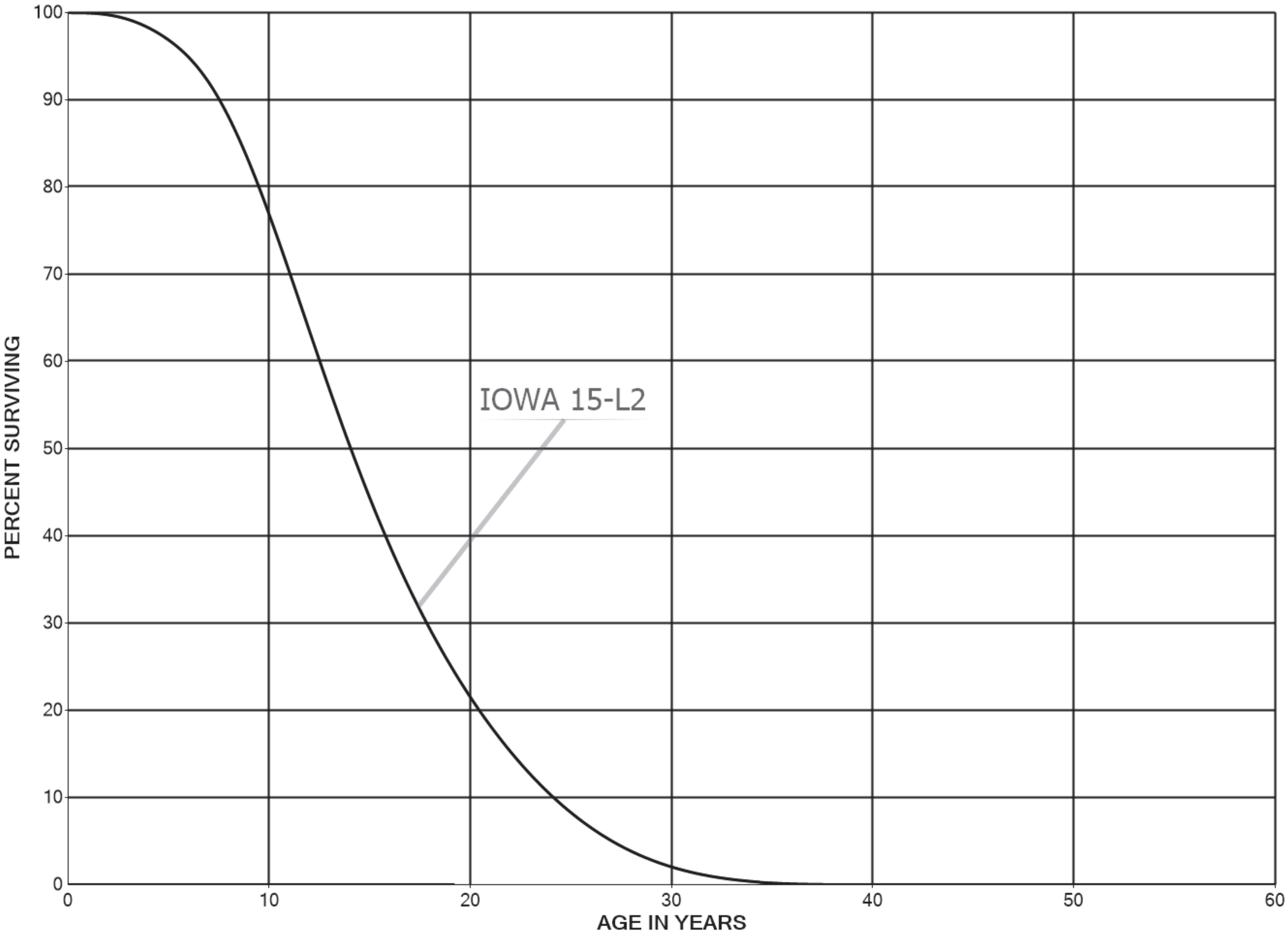
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES
SMOOTH SURVIVOR CURVE



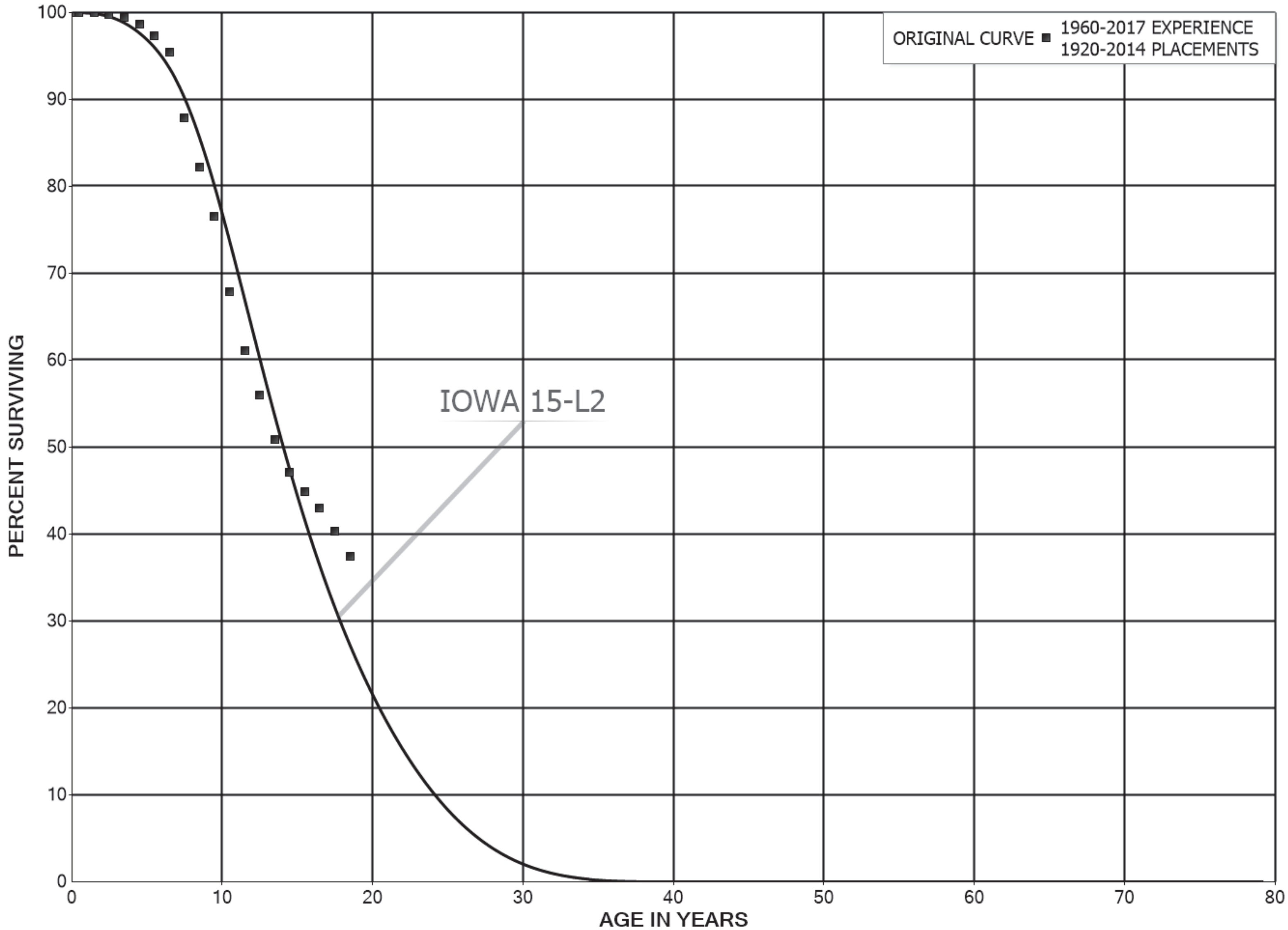
UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS
SMOOTH SURVIVOR CURVE



UGI UTILITIES, INC. - GAS DIVISION
ACCOUNT 396 POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1920-2014 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	11,151,393	6,630	0.0006	0.9994	100.00
0.5	11,299,895	1,306	0.0001	0.9999	99.94
1.5	11,342,468	18,033	0.0016	0.9984	99.93
2.5	11,366,402	38,671	0.0034	0.9966	99.77
3.5	11,486,630	89,144	0.0078	0.9922	99.43
4.5	11,360,461	159,779	0.0141	0.9859	98.66
5.5	11,257,712	217,059	0.0193	0.9807	97.27
6.5	11,010,165	871,307	0.0791	0.9209	95.40
7.5	10,087,867	645,663	0.0640	0.9360	87.85
8.5	9,192,389	636,400	0.0692	0.9308	82.22
9.5	8,495,355	962,363	0.1133	0.8867	76.53
10.5	7,269,576	731,410	0.1006	0.8994	67.86
11.5	6,403,469	528,163	0.0825	0.9175	61.03
12.5	5,617,439	514,970	0.0917	0.9083	56.00
13.5	4,551,827	344,987	0.0758	0.9242	50.87
14.5	4,015,226	189,174	0.0471	0.9529	47.01
15.5	3,612,980	152,205	0.0421	0.9579	44.80
16.5	3,370,926	208,416	0.0618	0.9382	42.91
17.5	3,147,032	221,185	0.0703	0.9297	40.26
18.5	2,903,244	60,304	0.0208	0.9792	37.43
19.5	2,618,348	30,566	0.0117	0.9883	36.65
20.5	2,469,772	76,612	0.0310	0.9690	36.22
21.5	2,269,625	60,038	0.0265	0.9735	35.10
22.5	2,017,373	7,422	0.0037	0.9963	34.17
23.5	1,817,051	43,804	0.0241	0.9759	34.04
24.5	1,582,152	103,516	0.0654	0.9346	33.22
25.5	1,309,079	122,003	0.0932	0.9068	31.05
26.5	1,150,702	41,247	0.0358	0.9642	28.16
27.5	1,084,622	41,175	0.0380	0.9620	27.15
28.5	989,833	35,400	0.0358	0.9642	26.12
29.5	866,508	69,913	0.0807	0.9193	25.18
30.5	776,796	68,508	0.0882	0.9118	23.15
31.5	653,297	13,411	0.0205	0.9795	21.11
32.5	589,610	34,766	0.0590	0.9410	20.68
33.5	513,382	40,234	0.0784	0.9216	19.46
34.5	464,606	18,476	0.0398	0.9602	17.93
35.5	380,327	20,812	0.0547	0.9453	17.22
36.5	289,360	10,204	0.0353	0.9647	16.28
37.5	269,806	4,189	0.0155	0.9845	15.70
38.5	256,976	16,440	0.0640	0.9360	15.46

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1920-2014 EXPERIENCE BAND 1960-2017

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	230,972	3,797	0.0164	0.9836	14.47
40.5	192,466	3,337	0.0173	0.9827	14.23
41.5	183,204	5,547	0.0303	0.9697	13.98
42.5	149,677	1,005	0.0067	0.9933	13.56
43.5	131,194	14,456	0.1102	0.8898	13.47
44.5	106,517	785	0.0074	0.9926	11.99
45.5	104,549	887	0.0085	0.9915	11.90
46.5	99,374	240	0.0024	0.9976	11.80
47.5	94,424	6,791	0.0719	0.9281	11.77
48.5	86,409		0.0000	1.0000	10.92
49.5	82,156	174	0.0021	0.9979	10.92
50.5	79,212	1,171	0.0148	0.9852	10.90
51.5	75,933		0.0000	1.0000	10.74
52.5	69,877		0.0000	1.0000	10.74
53.5	65,871		0.0000	1.0000	10.74
54.5	61,809	2,611	0.0422	0.9578	10.74
55.5	49,831		0.0000	1.0000	10.28
56.5	46,849	1,358	0.0290	0.9710	10.28
57.5	40,832		0.0000	1.0000	9.99
58.5	37,703		0.0000	1.0000	9.99
59.5	34,887		0.0000	1.0000	9.99
60.5	33,605		0.0000	1.0000	9.99
61.5	29,505	2,149	0.0728	0.9272	9.99
62.5	26,246		0.0000	1.0000	9.26
63.5	7,568		0.0000	1.0000	9.26
64.5	6,767		0.0000	1.0000	9.26
65.5	2,577		0.0000	1.0000	9.26
66.5	449		0.0000	1.0000	9.26
67.5	285		0.0000	1.0000	9.26
68.5	285		0.0000	1.0000	9.26
69.5					9.26

PART VII. DETAILED DEPRECIATION CALCULATIONS

CUMULATIVE DEPRECIATED ORIGINAL COST

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1849	2,795	2,795			0.0
1862	16	16			0.0
1867	72	72			0.0
1871	2,385	2,385			0.0
1879	659	659			0.0
1880	174	174			0.0
1881	398	398			0.0
1882	65	65			0.0
1883	45	45			0.0
1885	2	2			0.0
1887	47	45	2	2	0.0
1888	4,393	4,383	10	12	0.0
1889	26	26		12	0.0
1890	169	159	10	22	0.0
1891	7	6	1	23	0.0
1892	1,496	1,496		23	0.0
1893	203	188	15	38	0.0
1894	2,652	2,652		38	0.0
1895	75	71	4	42	0.0
1896	182	167	15	57	0.0
1897	3,934	3,928	6	63	0.0
1898	20,756	20,736	20	83	0.0
1899	9,296	9,194	102	185	0.0
1901	80,104	79,592	512	697	0.0
1902	16,889	16,802	87	784	0.0
1903	48,155	47,792	363	1,147	0.0
1904	68,788	67,721	1,067	2,214	0.0
1905	53,496	52,954	542	2,756	0.0
1906	14,921	13,657	1,264	4,020	0.0
1907	27,698	25,729	1,969	5,989	0.0
1908	45,067	40,920	4,147	10,136	0.0
1909	20,605	19,691	914	11,050	0.0
1910	21,501	18,593	2,908	13,958	0.0
1911	42,132	35,931	6,201	20,159	0.0
1912	27,899	23,453	4,446	24,605	0.0
1913	63,489	60,278	3,211	27,816	0.0
1914	62,667	54,887	7,780	35,596	0.0
1915	37,882	32,839	5,043	40,639	0.0
1916	29,576	26,511	3,065	43,704	0.0
1917	21,896	20,887	1,009	44,713	0.0
1918	16,684	13,250	3,434	48,147	0.0
1919	38,926	26,391	12,535	60,682	0.0
1920	54,227	39,175	15,052	75,734	0.0
1921	104,601	79,171	25,430	101,164	0.0
1922	110,991	66,515	44,476	145,640	0.0
1923	120,873	85,468	35,405	181,045	0.0

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1924	417,798	307,644	110,154	291,199	0.0
1925	161,542	120,625	40,917	332,116	0.0
1926	444,479	358,176	86,303	418,419	0.0
1927	229,373	180,294	49,079	467,498	0.0
1928	309,051	263,485	45,566	513,064	0.0
1929	238,854	169,435	69,419	582,483	0.0
1930	538,906	458,363	80,543	663,026	0.0
1931	467,533	395,282	72,251	735,277	0.0
1932	141,392	131,120	10,272	745,549	0.0
1933	166,507	162,341	4,166	749,715	0.0
1934	45,749	42,311	3,438	753,153	0.0
1935	52,603	46,247	6,356	759,509	0.0
1936	56,582	44,019	12,563	772,072	0.0
1937	58,770	52,689	6,081	778,153	0.0
1938	41,115	35,919	5,196	783,349	0.0
1939	68,749	52,962	15,787	799,136	0.0
1940	92,614	78,883	13,731	812,867	0.0
1941	178,178	153,561	24,617	837,484	0.0
1942	80,028	73,493	6,535	844,019	0.0
1943	31,438	28,643	2,795	846,814	0.0
1944	46,351	41,002	5,349	852,163	0.0
1945	50,205	46,921	3,284	855,447	0.0
1946	526,786	433,783	93,003	948,450	0.0
1947	193,921	158,005	35,916	984,366	0.0
1948	277,122	215,690	61,432	1,045,798	0.0
1949	660,722	581,674	79,048	1,124,846	0.0
1950	2,292,109	1,875,066	417,043	1,541,889	0.0
1951	699,283	556,325	142,958	1,684,847	0.1
1952	1,807,681	1,464,755	342,926	2,027,773	0.1
1953	1,550,356	1,138,776	411,580	2,439,353	0.1
1954	2,192,696	1,782,221	410,475	2,849,828	0.1
1955	3,211,266	2,693,257	518,009	3,367,837	0.1
1956	2,978,122	2,210,119	768,003	4,135,840	0.1
1957	5,270,428	4,050,625	1,219,803	5,355,643	0.2
1958	4,055,806	3,057,032	998,774	6,354,417	0.2
1959	4,018,817	2,919,494	1,099,323	7,453,740	0.2
1960	5,188,459	3,931,715	1,256,744	8,710,484	0.3
1961	5,392,717	4,114,277	1,278,440	9,988,924	0.3
1962	4,404,543	3,210,280	1,194,263	11,183,187	0.4
1963	6,043,954	4,313,843	1,730,111	12,913,298	0.4
1964	7,416,178	5,154,947	2,261,231	15,174,529	0.5
1965	9,392,706	6,644,106	2,748,600	17,923,129	0.6
1966	9,073,065	6,467,091	2,605,974	20,529,103	0.6
1967	9,223,069	6,534,051	2,689,018	23,218,121	0.7
1968	10,912,278	7,460,486	3,451,792	26,669,913	0.8
1969	11,461,584	7,778,975	3,682,609	30,352,522	1.0

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1970	10,491,411	7,165,909	3,325,502	33,678,024	1.1
1971	9,845,882	6,646,892	3,198,990	36,877,014	1.2
1972	10,866,514	7,082,117	3,784,397	40,661,411	1.3
1973	9,948,072	6,701,262	3,246,810	43,908,221	1.4
1974	10,527,579	7,307,912	3,219,667	47,127,888	1.5
1975	8,961,422	5,984,881	2,976,541	50,104,429	1.6
1976	8,577,773	5,682,388	2,895,385	52,999,814	1.7
1977	10,831,370	6,985,162	3,846,208	56,846,022	1.8
1978	10,274,989	6,468,454	3,806,535	60,652,557	1.9
1979	15,400,860	9,520,047	5,880,813	66,533,370	2.1
1980	27,422,290	16,976,780	10,445,510	76,978,880	2.4
1981	27,047,982	16,326,037	10,721,945	87,700,825	2.8
1982	26,796,224	17,284,519	9,511,705	97,212,530	3.1
1983	14,203,689	9,410,379	4,793,310	102,005,840	3.2
1984	18,627,318	12,027,231	6,600,087	108,605,927	3.4
1985	22,689,371	14,664,457	8,024,914	116,630,841	3.7
1986	27,310,343	17,088,287	10,222,056	126,852,897	4.0
1987	31,186,842	19,401,306	11,785,536	138,638,433	4.4
1988	41,760,318	24,918,279	16,842,039	155,480,472	4.9
1989	46,722,426	27,845,543	18,876,883	174,357,355	5.5
1990	49,497,047	28,876,994	20,620,053	194,977,408	6.1
1991	38,431,040	22,318,333	16,112,707	211,090,115	6.6
1992	44,397,986	25,873,761	18,524,225	229,614,340	7.2
1993	32,986,751	18,764,877	14,221,874	243,836,214	7.7
1994	50,389,581	28,411,051	21,978,530	265,814,744	8.4
1995	59,407,755	30,681,499	28,726,256	294,541,000	9.3
1996	62,362,796	30,589,632	31,773,164	326,314,164	10.3
1997	74,062,964	35,781,510	38,281,454	364,595,618	11.5
1998	60,170,663	28,716,267	31,454,396	396,050,014	12.5
1999	47,549,537	22,519,456	25,030,081	421,080,095	13.2
2000	60,974,939	26,882,932	34,092,007	455,172,102	14.3
2001	61,315,309	27,124,405	34,190,904	489,363,006	15.4
2002	57,549,970	25,266,281	32,283,689	521,646,695	16.4
2003	58,229,610	24,064,731	34,164,879	555,811,574	17.5
2004	76,807,052	32,312,933	44,494,119	600,305,693	18.9
2005	68,351,093	26,390,062	41,961,031	642,266,724	20.2
2006	65,365,116	26,422,449	38,942,667	681,209,391	21.4
2007	65,109,719	23,524,165	41,585,554	722,794,945	22.7
2008	68,854,996	23,032,982	45,822,014	768,616,959	24.2
2009	65,841,251	20,229,394	45,611,857	814,228,816	25.6
2010	60,795,037	17,845,731	42,949,306	857,178,122	27.0
2011	86,485,719	23,140,109	63,345,610	920,523,732	29.0
2012	104,510,715	25,252,023	79,258,692	999,782,424	31.4
2013	124,066,125	26,996,636	97,069,489	1,096,851,913	34.5
2014	157,169,180	30,185,084	126,984,096	1,223,836,009	38.5
2015	182,960,809	31,416,931	151,543,878	1,375,379,887	43.3

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2016	204,007,407	30,524,873	173,482,534	1,548,862,421	48.7
2017	204,501,606	25,835,176	178,666,430	1,727,528,851	54.3
2018	297,153,106	31,638,368	265,514,738	1,993,043,589	62.7
2019	274,125,428	25,252,854	248,872,574	2,241,916,163	70.5
2020	279,663,195	21,168,487	258,494,708	2,500,410,871	78.7
2021	314,452,650	13,109,856	301,342,794	2,801,753,665	88.1
2022	382,612,815	5,251,283	377,361,532	3,179,115,197	100.0
TOTAL	4,342,992,041	1,163,876,844	3,179,115,197		

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2003	7,183	6,194	989	989	0.0
2004	38,772	36,609	2,163	3,152	0.0
2005	39,966	30,931	9,035	12,187	0.0
2006	2,469	1,802	667	12,854	0.0
2007	878	602	276	13,130	0.0
2008	23,109	22,903	206	13,336	0.0
2009	4,753	2,837	1,916	15,252	0.0
2010	747,319	413,128	334,191	349,443	1.0
2014	22,225	22,225		349,443	1.0
2018	88,618	68,982	19,636	369,079	1.0
2019	33,840,603	3,459,121	30,381,482	30,750,561	85.2
2020	1,962,770	138,373	1,824,397	32,574,958	90.2
2021	1,747,559	309,092	1,438,467	34,013,425	94.2
2022	2,123,767	36,694	2,087,073	36,100,498	100.0
TOTAL	40,649,991	4,549,493	36,100,498		

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2003	22,684	21,948	736	736	0.0
2004	5,699	5,230	469	1,205	0.0
2007	1,760	1,354	406	1,611	0.0
2008	2,908,998	2,755,830	153,168	154,779	0.1
2011	425,873	319,977	105,896	260,675	0.2
2012	401,290	275,288	126,002	386,677	0.3
2013	524,329	428,174	96,155	482,832	0.3
2014	1,484,161	1,062,130	422,031	904,863	0.6
2015	732,103	514,192	217,911	1,122,774	0.8
2016	2,349,695	1,169,072	1,180,623	2,303,397	1.6
2017	77,621,819	28,102,869	49,518,950	51,822,347	36.1
2018	7,140,926	5,464,313	1,676,613	53,498,960	37.2
2019	74,206,213	21,797,992	52,408,221	105,907,181	73.7
2020	15,090,976	4,021,179	11,069,797	116,976,978	81.4
2021	14,002,023	1,764,227	12,237,796	129,214,774	90.0
2022	15,094,900	680,170	14,414,730	143,629,504	100.0
TOTAL	212,013,449	68,383,945	143,629,504		

READING SERVICE CENTER – INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES
READING SERVICE CENTER

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1974	574,898	502,086	72,812	72,812	11.1
1975	7,159	6,234	925	73,737	11.3
1976	1,630	1,415	215	73,952	11.3
1977	2,106	1,823	283	74,235	11.4
1978	554	478	76	74,311	11.4
1979	6,707	5,767	940	75,251	11.5
1980	28,234	24,196	4,038	79,289	12.1
1981	44,870	38,306	6,564	85,853	13.1
1982	428	369	59	85,912	13.2
1983	1,273	1,096	177	86,089	13.2
1984	1,922	1,644	278	86,367	13.2
1985	15,545	13,242	2,303	88,670	13.6
1986	1,123	952	171	88,841	13.6
1987	100	85	15	88,856	13.6
1989	40,014	33,425	6,589	95,445	14.6
1990	23,330	19,367	3,963	99,408	15.2
1992	95,013	77,811	17,202	116,610	17.9
1993	1,840	1,502	338	116,948	17.9
1994	27,142	21,972	5,170	122,118	18.7
1995	4,582	3,682	900	123,018	18.8
1996	248	198	50	123,068	18.8
1998	684	535	149	123,217	18.9
2000	72,144	55,265	16,879	140,096	21.4
2001	73,339	55,622	17,717	157,813	24.2
2002	5,527	4,136	1,391	159,204	24.4
2003	201	149	52	159,256	24.4
2004	1,509	1,096	413	159,669	24.4
2005	4,812	3,437	1,375	161,044	24.7
2006	458	322	136	161,180	24.7
2007	379,291	261,064	118,227	279,407	42.8
2008	444,898	299,012	145,886	425,293	65.1
2009	14,015	9,196	4,819	430,112	65.8
2010	2,629	1,675	954	431,066	66.0
2011	3,560	2,196	1,364	432,430	66.2
2012	295	175	120	432,550	66.2
2014	5,428	2,934	2,494	435,044	66.6
2015	44,230	22,488	21,742	456,786	69.9
2016	33,848	15,974	17,874	474,660	72.7
2017	6,680	2,874	3,806	478,466	73.2
2018	41,704	15,896	25,808	504,274	77.2
2019	106,886	34,570	72,316	576,590	88.3
2021	92,336	15,699	76,637	653,227	100.0
TOTAL	2,213,192	1,559,965	653,227		

UTILITY PLANT IN SERVICE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.2 PRODUCING LEASEHOLDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 55-S0.5						
NET SALVAGE PERCENT.. 0						
1892	1,496.50	1,496	1,497			
1894	2,650.57	2,651	2,651			
1897	3,621.53	3,622	3,622			
1898	13,387.22	13,387	13,387			
1899	1,044.85	1,045	1,045			
1901	748.25	748	748			
1902	4,491.26	4,491	4,491			
1904	8,221.11	8,221	8,221			
1905	43,088.40	43,088	43,088			
1906	1,680.87	1,681	1,681			
1907	471.47	471	471			
1908	75.00	75	75			
1909	1,941.30	1,941	1,941			
1911	526.00	526	526			
1912	2,693.57	2,694	2,694			
1913	31,916.65	31,771	31,917			
1914	1,141.85	1,130	1,142			
1917	1,200.00	1,165	1,200			
1918	701.79	677	702			
1919	1,973.32	1,891	1,973			
1921	2,993.63	2,831	2,994			
1923	1.00	1	1			
1926	4,047.55	3,705	4,048			
1928	1,435.71	1,297	1,436			
1929	962.33	863	962			
1935	951.47	819	951			
1937	52.56	45	53			
1939	15.58	13	16			
1940	13.75	11	14			
1941	15,225.35	12,532	15,225			
1944	2,221.48	1,786	2,221			
1945	161.26	129	161			
1946	629.70	498	630			
1948	1.00	1	1			
1950	181.23	139	181			
1954	35.07	26	35			
1956	7.72	6	8			
1959	142.79	100	143			
1960	131.99	92	132			
1962	47.49	32	47			
1963	10.00	7	10			
1972	6,120.00	3,703	6,120			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.2 PRODUCING LEASEHOLDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 55-S0.5						
NET SALVAGE PERCENT.. 0						
1973	7.08	4	7			
1990	260.71	147	256	4	25.31	
1998	3,274.34	1,524	2,657	617	28.13	22
2004	1,098.03	414	722	376	30.52	12
	163,100.33	153,496	162,102	998		34

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.4 0.02

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.4 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. 0						
1898	11.00	11	11			
1899	76.80	77	77			
1903	286.00	284	286			
1905	534.24	525	534			
1906	439.95	430	440			
1907	1,303.60	1,267	1,304			
1908	371.67	359	372			
1909	542.65	521	543			
1910	24.50	23	25			
1912	1.00	1	1			
1913	308.44	290	308			
1914	406.05	379	406			
1915	104.20	97	104			
1916	83.46	77	83			
1917	271.07	249	271			
1918	13.60	12	14			
1919	364.18	331	364			
1920	372.95	337	373			
1921	422.37	380	422			
1922	3.00	3	3			
1923	214.30	190	214			
1924	233.93	207	234			
1925	186.30	164	186			
1926	648.74	566	649			
1927	81.77	71	82			
1928	1,265.69	1,092	1,266			
1929	342.53	294	343			
1930	105.29	90	105			
1931	153.25	130	153			
1932	259.70	218	260			
1933	11.55	10	12			
1934	99.17	82	99			
1935	711.79	586	712			
1936	219.39	179	219			
1937	178.48	145	178			
1938	16.54	13	17			
1939	97.49	78	97			
1940	1,167.50	926	1,168			
1941	4,651.28	3,659	4,651			
1942	570.16	445	570			
1943	210.83	163	211			
1944	372.59	286	373			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.4 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. 0						
1945	869.26	661	869			
1946	288.26	217	288			
1947	1,980.20	1,480	1,980			
1948	494.28	366	494			
1949	1,215.91	892	1,216			
1950	409.99	298	410			
1951	8.42	6	8			
1952	174.36	124	174			
1953	33.53	24	34			
1954	319.31	223	319			
1955	18.46	13	18			
1956	100.07	68	100			
1957	5.20	4	5			
1958	125.16	84	125			
1959	78.61	52	79			
1960	140.63	92	141			
1961	48.55	31	49			
1962	238.74	152	239			
1963	73.00	46	73			
1964	30.64	19	31			
1965	327.04	200	325	2	23.27	
1966	1,949.99	1,177	1,913	37	23.77	2
1967	210.02	125	203	7	24.28	
1968	601.24	353	574	27	24.79	1
1969	260.06	150	244	16	25.32	1
1970	30.26	17	28	3	25.84	
1971	494.97	277	450	45	26.37	2
1972	59.23	33	54	6	26.91	
1973	350.14	190	309	41	27.46	1
1974	44.07	23	37	7	28.01	
1975	183.82	96	156	28	28.56	1
1976	51.01	26	42	9	29.12	
1977	10.01	5	8	2	29.69	
1983	289.96	170	276	14	28.07	
1992	292.64	143	232	60	32.00	2
1999	643.99	260	423	221	34.64	6
2011	87.04	20	33	55	37.52	1
	30,277.07	23,364	29,699	578		17

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.0 0.06

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 328 FIELD MEASURING AND REGULATING STATION STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1932	154.10	154	154			
1946	22.99	23	23			
1954	330.80	331	331			
1962	466.92	467	467			
1963	288.39	288	288			
	1,263.20	1,263	1,263			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 329 OTHER STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1926	189.95	190	190			
1928	18,125.42	18,125	18,125			
1931	33.50	34	34			
1933	286.63	287	287			
1949	75.00	75	75			
1954	1,624.46	1,624	1,624			
1956	1,968.24	1,968	1,968			
1957	165.09	165	165			
1958	4,854.42	4,854	4,854			
1959	592.97	593	593			
1960	6,765.22	6,765	6,765			
1961	3,361.70	3,362	3,362			
1962	1,509.75	1,510	1,510			
1965	132.84	133	133			
1968	78.04	78	78			
1980	5,021.43	5,021	5,020	2		
	44,784.66	44,784	44,783	2		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 330 PRODUCING GAS WELLS - WELL CONSTRUCTION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1924	704.67	705	705			
1927	1,923.69	1,924	1,924			
1931	1,001.26	1,001	1,001			
1934	627.61	628	628			
1936	108.46	108	108			
1940	17.42	17	17			
1942	3,414.11	3,414	3,414			
1943	779.98	780	780			
1945	470.98	471	471			
1946	6,271.05	6,271	6,271			
1947	904.72	905	905			
1948	274.43	274	274			
1955	331.39	331	331			
1972	894.00	894	894			
2004	484.83	485	485			
	18,208.60	18,208	18,209			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 331 PRODUCING GAS WELLS - WELL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1901	115.50	116	116			
1902	202.95	203	203			
1905	127.93	128	128			
1906	12.45	12	12			
1907	1,080.85	1,081	1,081			
1908	1,477.83	1,478	1,478			
1909	298.52	299	299			
1910	158.72	159	159			
1911	277.88	278	278			
1912	291.82	292	292			
1913	214.87	215	215			
1915	441.31	441	441			
1916	189.45	189	189			
1920	640.55	641	641			
1924	501.79	502	502			
1927	432.64	433	433			
1928	569.18	569	569			
1931	299.31	299	299			
1939	388.95	389	389			
1940	380.36	380	380			
1942	672.69	673	673			
1943	957.14	957	957			
1944	255.87	256	256			
1946	812.99	813	813			
1947	296.62	297	297			
1951	235.61	236	236			
1955	200.97	201	201			
1962	296.02	296	296			
1964	413.45	413	413			
1965	1,320.34	1,320	1,320			
1972	10,716.00	10,716	10,716			
1981	66.91	67	67			
1987	93.25	93	94			
	24,440.72	24,442	24,441			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

CPG
SURVIVOR CURVE.. IOWA 47-L0
NET SALVAGE PERCENT.. 0

1895	16.96	13	17			
1898	6,981.14	5,416	6,981			
1899	7,115.14	5,497	7,115			
1901	2,982.56	2,285	2,983			
1902	9,652.93	7,361	9,653			
1903	13,659.72	10,370	13,660			
1904	14,815.75	11,197	14,816			
1905	1,275.77	960	1,276			
1906	513.25	384	513			
1907	6,359.95	4,740	6,360			
1908	3,151.76	2,338	3,152			
1909	2,862.37	2,113	2,862			
1910	307.46	226	307			
1911	2,431.84	1,778	2,432			
1912	2,319.31	1,688	2,319			
1913	5,593.31	4,049	5,593			
1914	6,309.19	4,544	6,309			
1915	4,636.59	3,323	4,637			
1916	6,215.03	4,431	6,215			
1917	4,867.38	3,452	4,867			
1918	88.42	62	88			
1919	3,165.58	2,221	3,166			
1920	11,810.32	8,242	11,810			
1921	1,551.67	1,077	1,552			
1922	4,953.14	3,418	4,953			
1923	1,197.31	822	1,197			
1924	26,520.98	18,091	26,521			
1925	3,581.94	2,430	3,582			
1926	846.23	571	846			
1927	8,969.93	6,012	8,970			
1928	500.19	333	500			
1929	1,246.96	825	1,247			
1930	822.22	541	822			
1931	5,959.34	3,896	5,959			
1932	284.85	185	285			
1933	295.44	191	295			
1934	1,434.24	919	1,434			
1935	734.99	468	735			
1936	655.62	415	656			
1937	590.14	371	590			
1938	1,716.44	1,070	1,716			
1939	6,274.96	3,885	6,275			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 47-L0						
NET SALVAGE PERCENT.. 0						
1940	20,933.33	12,867	20,933			
1941	54,988.08	33,554	54,988			
1942	8,386.40	5,078	8,386			
1943	3,472.45	2,087	3,472			
1944	5,918.84	3,530	5,919			
1945	5,041.98	2,983	5,042			
1946	8,811.89	5,171	8,812			
1947	10,683.12	6,219	10,683			
1948	2,599.34	1,500	2,599			
1949	50,912.72	29,150	50,913			
1950	7,587.88	4,307	7,588			
1951	1,414.44	796	1,414			
1952	2,347.14	1,309	2,347			
1953	485.25	268	485			
1954	7,899.95	4,325	7,900			
1955	7,421.47	4,025	7,421			
1956	7,758.34	4,168	7,758			
1957	11,247.12	5,982	11,247			
1958	19,011.79	10,016	19,012			
1959	5,911.91	3,083	5,912			
1960	9,496.60	4,900	9,474	23	22.75	1
1961	6,128.13	3,129	6,050	79	23.00	3
1962	12,642.83	6,386	12,347	296	23.26	13
1963	10,595.86	5,293	10,233	362	23.52	15
1964	15,728.29	7,770	15,022	706	23.78	30
1965	23,533.62	11,491	22,217	1,317	24.05	55
1966	12,682.25	6,123	11,838	844	24.31	35
1967	21,327.23	10,169	19,661	1,667	24.59	68
1968	24,415.86	11,501	22,236	2,180	24.86	88
1969	23,449.66	10,912	21,097	2,353	25.13	94
1970	9,454.39	4,343	8,397	1,058	25.41	42
1971	20,918.97	9,485	18,338	2,581	25.69	100
1972	26,190.05	11,713	22,646	3,544	25.98	136
1973	25,358.45	11,190	21,635	3,724	26.26	142
1974	4,139.67	1,801	3,482	658	26.55	25
1975	7,177.74	3,077	5,949	1,229	26.85	46
1976	1,091.28	461	891	200	27.14	7
1977	6,710.04	2,793	5,400	1,310	27.44	48
1980	250.51	99	191	59	28.36	2
1982	1,631.45	1,044	1,631			
1983	2,373.67	1,500	2,374			
1985	1,137.79	700	1,138			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 47-L0						
NET SALVAGE PERCENT.. 0						
1987	1,947.22	1,168	1,947			
1988	7.07	4	7			
1993	1,441.13	787	1,441			
1995	797.78	421	798			
1997	1,112.78	562	1,113			
1998	50,846.74	25,164	50,163	684	25.00	27
	750,688.82	426,614	725,816	24,873		977

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.5   0.13

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 24-O3						
NET SALVAGE PERCENT.. 0						
1931	204.20	199	204			
1936	120.07	105	120			
1941	517.12	398	517			
1942	63.36	47	63			
1943	66.33	48	66			
1945	162.93	112	163			
1946	149.20	100	149			
1947	66.33	43	66			
1948	377.00	237	377			
1949	71.07	43	71			
1950	309.80	183	310			
1952	5,204.61	2,871	4,973	232	10.76	22
1953	1,807.46	962	1,666	141	11.22	13
1957	286.49	131	227	60	13.00	5
1962	1,101.38	407	705	396	15.13	26
1963	4,056.52	1,430	2,477	1,580	15.54	102
1964	170.93	57	99	72	15.94	5
1965	299.84	96	166	134	16.34	8
1966	50.59	15	26	25	16.73	1
1967	1,350.83	387	670	681	17.12	40
1969	2,210.03	565	979	1,231	17.86	69
1970	303.35	73	126	177	18.23	10
1972	595.45	126	218	377	18.92	20
1973	346.72	68	118	229	19.26	12
1975	403.54	69	120	284	19.91	14
1976	97.38	15	26	71	20.21	4
1978	28.40	4	7	21	20.80	1
1979	1,083.00	132	229	854	21.07	41
1980	339.25	38	66	273	21.34	13
1983	53.86	37	54			
1984	379.02	258	379			
1986	2,651.47	1,771	2,651			
1987	6,747.73	4,456	6,748			
1988	1,817.19	1,191	1,817			
1989	141.62	92	142			
1990	1,111.30	715	1,111			
1992	5,631.37	3,556	5,631			
1993	4,412.23	2,759	4,412			
1994	19,381.40	11,985	19,381			
1995	442.09	271	442			
1996	495.45	301	495			
1997	2,814.04	1,686	2,814			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 24-O3						
NET SALVAGE PERCENT.. 0						
2005	37.73	20	38			
2006	8,910.59	4,705	8,911			
2007	11,670.35	6,042	11,670			
2011	1,184.07	549	3,267	2,083-		
	89,724.69	49,355	84,969	4,756		406

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.7 0.45

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 335 DRILLING AND CLEANING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-S0.5						
NET SALVAGE PERCENT.. 0						
1956	11,947.50	11,948	11,948			
1967	4,088.00	3,873	4,088			
1968	19,012.74	17,796	19,013			
1972	5,152.00	4,592	5,152			
1981	3,694.10	2,913	3,606	88	6.34	14
1988	4,516.83	3,662	4,517			
1991	1,192.55	924	1,160	33	9.15	4
	49,603.72	45,708	49,483	121		18

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.7   0.04

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 337 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1928	67.99	68	68			
1940	980.88	981	981			
1941	1,425.13	1,425	1,425			
1950	572.00	572	572			
1952	46.00	46	46			
1954	47.17	47	47			
1956	112.81	113	113			
1959	477.96	478	478			
1961	614.73	615	615			
1963	1,381.00	1,381	1,381			
1966	4,766.93	4,767	4,767			
1967	157.76	158	158			
1968	150.15	150	150			
1969	23.17	23	23			
1970	238.47	238	238			
	11,062.15	11,062	11,062			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1883	45.00	45	45			
1897	69.45	69	69			
1903	3,610.27	3,610	3,610			
1904	4,110.54	4,111	4,111			
1909	44.05	44	44			
1911	85.13	85	85			
1913	835.22	835	835			
1914	222.36	222	222			
1915	14.50	14	15			
1916	224.10	223	224			
1917	117.50	117	118			
1918	64.30	64	64			
1927	6,471.58	6,250	6,399	73	2.40	30
1930	1,806.23	1,725	1,766	40	3.13	13
1931	2,041.31	1,943	1,989	52	3.38	15
1932	27,123.22	25,713	26,325	798	3.64	219
1933	2,640.53	2,493	2,552	88	3.90	23
1934	538.99	507	519	20	4.16	5
1935	812.94	762	780	33	4.42	7
1936	12.64	12	12			
1938	203.24	188	192	11	5.23	2
1939	375.47	346	354	21	5.51	4
1940	962.92	883	904	59	5.79	10
1941	6,450.60	5,891	6,031	419	6.07	69
1942	592.71	539	552	41	6.37	6
1943	337.44	305	312	25	6.67	4
1944	60.01	54	55	5	6.99	1
1945	422.25	378	387	35	7.31	5
1946	631.09	562	575	56	7.65	7
1947	3,351.10	2,968	3,039	312	8.00	39
1948	2,508.33	2,209	2,262	247	8.36	30
1949	4,635.54	4,056	4,153	483	8.75	55
1950	1,157.34	1,006	1,030	127	9.15	14
1951	190.65	165	169	22	9.57	2
1952	4,042.41	3,464	3,546	496	10.02	50
1953	198.20	169	173	25	10.48	2
1954	5,400.53	4,554	4,662	738	10.97	67
1955	14,353.89	12,000	12,286	2,068	11.48	180
1956	8,390.67	6,951	7,116	1,274	12.01	106
1957	78,471.52	64,380	65,912	12,559	12.57	999
1958	2,231.51	1,812	1,855	376	13.15	29
1959	3,854.85	3,097	3,171	684	13.76	50

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1960	3,405.26	2,706	2,770	635	14.38	44
1961	11,197.19	8,795	9,004	2,193	15.02	146
1962	2,660.99	2,065	2,114	547	15.67	35
1963	3,222.41	2,471	2,530	693	16.33	42
1964	3,157.03	2,390	2,447	710	17.01	42
1965	5,365.41	4,009	4,104	1,261	17.70	71
1966	6,572.95	4,846	4,961	1,612	18.39	88
1967	36,334.10	26,420	27,049	9,285	19.10	486
1968	22,318.73	16,003	16,384	5,935	19.81	300
1969	3,796.90	2,683	2,747	1,050	20.54	51
1970	12,470.57	8,680	8,887	3,584	21.28	168
1971	18,015.96	12,346	12,640	5,376	22.03	244
1972	1,199.64	809	828	371	22.78	16
1973	11,935.28	7,920	8,109	3,827	23.55	163
1974	5,080.37	3,315	3,394	1,686	24.33	69
1975	8,346.12	5,351	5,478	2,868	25.12	114
1976	11,480.98	7,228	7,400	4,081	25.93	157
1977	7,995.15	4,941	5,059	2,937	26.74	110
1978	11,905.30	7,218	7,390	4,515	27.56	164
1979	12,918.41	7,679	7,862	5,057	28.39	178
1980	7,570.24	4,409	4,514	3,056	29.23	105
1981	4,856.13	2,769	2,835	2,021	30.09	67
1982	73,749.17	43,306	44,337	29,412	28.47	1,033
1983	10,050.64	5,757	5,894	4,157	29.46	141
1984	9,041.47	5,082	5,203	3,839	29.99	128
1985	15,250.78	8,350	8,549	6,702	30.99	216
1986	26,754.50	14,356	14,698	12,057	31.52	383
1987	14,112.19	7,364	7,539	6,573	32.53	202
1988	3,342.10	1,695	1,735	1,607	33.52	48
1989	11,301.63	5,603	5,736	5,565	34.07	163
1990	1,090.00	524	536	554	35.07	16
1991	8,000.14	3,730	3,819	4,181	36.07	116
1992	117,309.04	52,953	54,213	63,096	37.07	1,702
1993	25,030.74	11,004	11,266	13,765	37.61	366
1994	12,460.42	5,291	5,417	7,043	38.62	182
1995	6,889.97	2,824	2,891	3,999	39.61	101
1996	12,673.77	5,004	5,123	7,551	40.62	186
1997	12,902.15	4,935	5,052	7,850	41.17	191
1998	66,382.78	24,396	24,977	41,406	42.17	982
1999	16,831.93	5,933	6,074	10,758	43.17	249
2000	2,877.07	971	994	1,883	44.17	43
2001	5,944.43	1,917	1,963	3,982	45.17	88

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
2002	2,355.47	724	741	1,614	46.17	35
2003	1,306.89	385	394	913	46.73	20
2004	373.65	104	106	267	47.72	6
2007	10,611.38	2,483	2,542	8,069	50.73	159
	868,159.56	524,565	536,830	331,330		11,659

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.4 1.34

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
1916	44.03	44	44			
1932	22.41	22	22			
1937	428.90	429	429			
1940	2,662.19	2,662	2,662			
1941	342.66	343	343			
1947	195.14	195	195			
1954	97.16	97	97			
1955	398.72	399	399			
1956	1,082.26	1,082	1,082			
1957	2,295.78	2,296	2,296			
1958	310.18	310	310			
1959	2,058.46	2,058	2,058			
1960	300.33	300	300			
1961	6,541.37	6,541	6,541			
1962	4,353.35	4,353	4,353			
1963	2,282.71	2,262	2,283			
1964	736.08	721	736			
1965	190.55	185	191			
1966	2,343.06	2,245	2,343			
1967	2,250.24	2,130	2,250			
1968	9,977.71	9,342	9,978			
1969	2,151.32	1,993	2,151			
1970	544.69	499	545			
1971	40.03	36	40			
1972	1,214.19	1,088	1,214			
1974	700.59	614	701			
1975	4,750.87	4,111	4,751			
1978	193.66	161	190	3	5.04	1
1979	2,207.46	1,811	2,143	65	5.39	12
1980	2,203.60	1,781	2,107	96	5.75	17
1984	5,281.99	4,494	5,282			
1985	369.17	310	367	2	7.14	
1986	9,821.44	8,173	9,674	148	7.36	20
1987	241.46	198	234	7	7.79	1
1988	1,014.54	819	969	45	8.24	5
1989	31,015.80	24,729	29,269	1,746	8.52	205
1990	44,844.88	35,270	41,746	3,099	8.82	351
1995	601.90	432	511	91	10.81	8
1997	1,215.58	834	987	228	11.67	20
1999	1,575.63	1,029	1,218	358	12.47	29

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
2004	1,760.08	983	1,163	597	14.61	41
2019	11,416.29	1,806	2,138	9,279	18.62	498
2020	138.01	17	20	118	18.29	6
	162,216.47	129,204	146,334	15,882		1,214

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.1 0.75

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

CPG
SURVIVOR CURVE.. IOWA 70-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1901	71,233.81	71,234	71,234			
1903	24,056.23	24,056	24,056			
1904	33,197.34	33,197	33,197			
1905	1,964.62	1,952	1,965			
1907	2,420.69	2,395	2,421			
1908	8,730.25	8,616	8,730			
1911	749.15	732	749			
1914	1,738.46	1,680	1,738			
1916	77.22	74	77			
1923	35.55	33	36			
1926	1,356.81	1,252	1,357			
1927	46,464.38	42,714	46,464			
1928	2,171.63	1,988	2,172			
1929	180.25	164	180			
1930	27,529.19	25,000	27,529			
1931	2,522.76	2,282	2,523			
1932	296.56	267	297			
1933	122,819.26	110,152	122,819			
1934	4,897.35	4,373	4,897			
1935	10,855.44	9,650	10,855			
1936	1,410.95	1,249	1,411			
1937	16,622.35	14,642	16,622			
1938	2,388.88	2,094	2,389			
1939	2,797.65	2,440	2,798			
1940	797.65	692	798			
1941	11,364.66	9,809	11,365			
1942	11,633.51	9,987	11,634			
1943	1,215.69	1,038	1,216			
1944	5,838.88	4,954	5,839			
1945	48.34	41	48			
1946	1,498.10	1,255	1,480	18	11.35	2
1947	4,905.03	4,082	4,814	91	11.74	8
1948	24,941.60	20,612	24,306	635	12.15	52
1949	98,837.20	81,103	95,640	3,198	12.56	255
1950	28,199.11	22,966	27,082	1,117	12.99	86
1951	2,735.68	2,211	2,607	128	13.43	10
1952	202,177.37	162,059	191,106	11,072	13.89	797
1953	22,207.66	17,652	20,816	1,392	14.36	97
1954	200,020.82	157,616	185,866	14,154	14.84	954
1955	798,248.09	623,320	735,041	63,207	15.34	4,120
1956	81,749.31	63,239	74,574	7,176	15.85	453
1957	1,473,781.22	1,129,123	1,331,502	142,280	16.37	8,692

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
1958	311,182.44	236,010	278,311	32,871	16.91	1,944
1959	299,804.72	225,024	265,356	34,448	17.46	1,973
1960	613,382.05	455,393	537,015	76,367	18.03	4,236
1961	674,919.59	495,587	584,414	90,506	18.60	4,866
1962	47,891.52	34,763	40,994	6,898	19.19	359
1963	190,718.09	136,800	161,319	29,399	19.79	1,486
1964	122,060.87	86,472	101,971	20,090	20.41	984
1965	290,969.66	203,554	240,038	50,932	21.03	2,422
1966	701,420.51	484,282	571,082	130,338	21.67	6,015
1967	720,897.81	491,032	579,042	141,856	22.32	6,356
1968	215,827.53	144,974	170,958	44,869	22.98	1,953
1969	370,389.64	245,250	289,207	81,182	23.65	3,433
1970	640,788.57	418,070	493,003	147,786	24.33	6,074
1971	875,035.93	562,272	663,051	211,985	25.02	8,473
1972	453,960.20	287,162	338,632	115,329	25.72	4,484
1973	966,619.22	601,653	709,490	257,129	26.43	9,729
1974	373,697.43	228,811	269,822	103,875	27.14	3,827
1975	486,480.16	292,793	345,272	141,208	27.87	5,067
1976	297,117.41	175,683	207,172	89,946	28.61	3,144
1977	137,471.87	79,831	94,140	43,332	29.35	1,476
1978	136,380.55	77,718	91,648	44,733	30.11	1,486
1979	287,058.05	160,465	189,226	97,832	30.87	3,169
1980	501,981.46	275,086	324,391	177,590	31.64	5,613
1981	243,613.68	130,786	154,227	89,386	32.42	2,757
1982	283,711.51	163,162	192,406	91,305	29.92	3,052
1983	319,398.12	180,396	212,729	106,669	30.43	3,505
1984	524,887.81	290,998	343,155	181,733	30.94	5,874
1985	749,802.45	404,893	477,464	272,338	31.94	8,527
1986	455,843.70	241,232	284,469	171,374	32.47	5,278
1987	565,064.08	292,873	345,366	219,698	32.99	6,660
1988	414,536.27	208,802	246,227	168,310	33.99	4,952
1989	491,903.15	242,213	285,626	206,277	34.53	5,974
1990	207,476.32	99,796	117,683	89,793	35.07	2,560
1991	360,151.18	167,902	197,996	162,155	36.07	4,496
1992	2,298,208.76	1,044,306	1,231,482	1,066,726	36.62	29,130
1993	1,177,930.89	517,818	610,629	567,302	37.61	15,084
1994	1,136,543.85	485,872	572,957	563,586	38.17	14,765
1995	971,986.45	403,569	475,903	496,084	38.73	12,809
1996	571,723.50	228,804	269,814	301,910	39.72	7,601
1997	818,847.73	317,385	374,272	444,576	40.29	11,034
1998	2,005,922.41	747,006	880,896	1,125,027	41.29	27,247
1999	1,775,496.88	638,469	752,905	1,022,592	41.86	24,429

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
2000	1,018,766.50	350,659	413,509	605,257	42.86	14,122
2001	2,255,155.44	746,682	880,514	1,374,642	43.44	31,645
2002	827,071.64	262,843	309,954	517,118	44.01	11,750
2003	1,841,712.23	556,565	656,321	1,185,391	45.02	26,330
2004	339,445.60	97,964	115,523	223,923	45.60	4,911
2005	46,687.55	12,746	15,031	31,657	46.60	679
2006	317,437.09	82,216	96,952	220,485	47.20	4,671
2007	479,147.65	116,625	137,528	341,619	48.19	7,089
2008	171,988.56	39,403	46,465	125,523	48.79	2,573
2009	12,014.64	2,563	3,022	8,992	49.79	181
2010	222,615.19	44,256	52,188	170,427	50.39	3,382
2011	140,623.77	25,706	30,313	110,310	51.40	2,146
2012	28,451.16	4,780	5,637	22,814	52.00	439
2013	2,361,672.12	358,974	423,315	1,938,357	53.00	36,573
2014	9,397.12	1,286	1,516	7,881	53.61	147
2021	556,489.83	13,912	16,406	540,084	58.38	9,251
	39,074,496.81	18,596,142	21,888,205	17,186,292		455,718

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.7 1.17

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2						
NET SALVAGE PERCENT.. 0						
1928	43.41	43	43			
1936	1.00	1	1			
1938	63.36	61	63			
1939	130.20	125	130			
1940	199.99	191	200			
1941	188.95	179	189			
1943	115.52	108	116			
1944	207.70	193	208			
1945	83.77	78	84			
1946	174.42	160	174			
1947	163.63	149	164			
1948	277.29	252	277			
1949	89.09	80	89			
1951	7.97	7	8			
1953	18.79	16	19			
1954	5,944.35	5,181	5,944			
1955	8,508.82	7,364	8,509			
1956	7,542.08	6,480	7,542			
1957	39,702.37	33,861	39,702			
1958	13,574.54	11,491	13,575			
1959	6,469.06	5,434	6,469			
1960	9,801.88	8,168	9,756	46	8.17	6
1961	24,067.26	19,887	23,753	314	8.51	37
1962	5,498.45	4,505	5,381	118	8.85	13
1963	12,455.03	10,116	12,082	373	9.20	41
1964	5,203.12	4,187	5,001	202	9.57	21
1965	19,172.75	15,283	18,254	919	9.94	92
1966	16,408.17	12,952	15,470	938	10.32	91
1967	43,116.46	33,683	40,231	2,886	10.72	269
1968	18,626.28	14,399	17,198	1,428	11.12	128
1969	18,055.59	13,803	16,486	1,569	11.54	136
1970	32,278.33	24,400	29,143	3,135	11.96	262
1971	15,250.12	11,391	13,605	1,645	12.40	133
1972	26,308.31	19,404	23,176	3,132	12.86	244
1973	26,694.33	19,438	23,217	3,478	13.32	261
1974	12,036.90	8,649	10,330	1,707	13.79	124
1975	18,632.52	13,202	15,768	2,864	14.28	201
1976	30,467.80	21,278	25,414	5,054	14.78	342
1977	138,678.97	95,406	113,952	24,727	15.29	1,617
1978	14,832.80	10,044	11,996	2,836	15.82	179
1979	22,161.07	14,762	17,632	4,529	16.36	277
1980	41,008.38	26,865	32,087	8,921	16.90	528

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2						
NET SALVAGE PERCENT.. 0						
1981	13,577.55	8,739	10,438	3,140	17.46	180
1982	82,437.31	59,091	70,578	11,859	16.00	741
1983	156,845.27	110,278	131,715	25,130	16.68	1,507
1984	24,048.18	16,665	19,905	4,144	17.06	243
1985	50,677.87	34,588	41,312	9,366	17.45	537
1986	86,879.75	58,036	69,318	17,562	18.14	968
1987	86,985.91	57,132	68,238	18,748	18.55	1,011
1988	52,185.49	33,670	40,215	11,970	18.97	631
1989	411,643.09	259,253	309,650	101,993	19.69	5,180
1990	41,658.60	25,724	30,725	10,934	20.13	543
1991	297,917.74	180,181	215,207	82,711	20.58	4,019
1992	147,610.27	87,341	104,319	43,291	21.05	2,057
1993	264,883.76	152,361	181,979	82,905	21.78	3,806
1994	163,266.69	91,658	109,476	53,791	22.26	2,416
1995	349,935.44	191,485	228,708	121,227	22.75	5,329
1996	117,235.62	62,440	74,578	42,658	23.25	1,835
1997	215,121.50	110,809	132,349	82,772	24.00	3,449
1998	739,635.18	369,670	441,531	298,104	24.52	12,158
1999	555,284.44	268,813	321,068	234,216	25.04	9,354
2000	30,572.58	14,308	17,089	13,483	25.58	527
2001	311,654.86	140,712	168,065	143,590	26.12	5,497
2002	420,021.01	182,541	218,025	201,996	26.67	7,574
2003	302,736.01	126,332	150,890	151,846	27.23	5,576
2004	113,854.85	45,496	54,340	59,515	27.80	2,141
2005	92,462.88	35,275	42,132	50,331	28.37	1,774
2006	61,754.44	22,417	26,775	34,980	28.95	1,208
2007	43,243.40	14,880	17,773	25,471	29.55	862
2008	249,781.89	81,479	97,318	152,464	29.95	5,091
2012	19,034.42	4,698	5,611	13,423	32.05	419
2013	11,199.27	2,532	3,024	8,175	32.52	251
2021	3,931.62	166	198	3,733	34.09	110
	6,152,337.72	3,322,046	3,965,987	2,186,351		91,996

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.8   1.50

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 370 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 23-R0.5						
NET SALVAGE PERCENT.. 0						
1956	5,466.25	5,466	5,466			
1966	7,727.57	7,728	7,728			
1967	1,743.15	1,743	1,743			
1968	249.76	250	250			
1969	2,500.34	2,500	2,500			
1973	1,946.45	1,946	1,946			
1980	706.12	655	706			
1983	5,572.11	5,194	5,572			
1984	1,354.71	1,252	1,355			
1985	2,338.50	2,131	2,339			
1986	8,363.40	7,540	8,363			
1987	1,865.01	1,662	1,865			
1988	8,236.27	7,246	8,236			
1989	56,812.32	49,290	56,812			
1990	6,202.17	5,321	6,202			
1991	81,477.96	68,784	81,478			
1992	19,398.63	16,151	19,399			
1993	11,826.34	9,699	11,826			
1994	4,988.84	4,024	4,989			
1995	24,237.82	19,264	24,178	60	7.10	8
1996	53,971.10	42,049	52,774	1,197	7.51	159
1997	2,814.71	2,153	2,702	113	7.83	14
1998	270.53	203	255	16	8.18	2
2000	83,012.05	59,395	74,545	8,467	8.95	946
2001	21,876.59	15,239	19,126	2,751	9.36	294
2004	19,336.59	12,377	15,534	3,803	10.40	366
2009	239,511.48	125,791	157,876	81,636	12.21	6,686
2010	493,162.42	246,581	309,475	183,687	12.50	14,695
2011	679,759.29	322,070	404,219	275,540	12.77	21,577
2012	572,350.00	254,810	319,803	252,547	13.08	19,308
2013	629,591.21	261,973	328,793	300,798	13.33	22,565
2014	214,236.53	82,481	103,519	110,717	13.58	8,153
2015	223,230.20	78,845	98,956	124,275	13.73	9,051
	3,486,136.42	1,721,813	2,140,531	1,345,605		103,824

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.0   2.98

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

CPG
SURVIVOR CURVE.. IOWA 35-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1932	73.41	73	73			
1933	22.79	23	23			
1935	159.65	160	160			
1936	148.67	149	149			
1938	75.60	76	76			
1939	348.00	348	348			
1953	193.45	193	193			
1957	802.14	802	802			
1959	54.05	53	54			
1960	1,630.62	1,601	1,631			
1963	268.78	258	269			
1965	542.39	512	542			
1966	237.71	222	238			
1967	1,610.42	1,497	1,610			
1968	1,046.31	966	1,046			
1969	8,185.23	7,502	8,185			
1970	1,294.81	1,179	1,295			
1971	2,302.48	2,081	2,302			
1972	4,402.26	3,952	4,402			
1973	6,378.34	5,684	6,378			
1974	2,116.13	1,872	2,116			
1975	772.96	679	773			
1976	728.51	634	729			
1977	666.84	576	663	4	4.77	1
1978	2,372.22	2,031	2,338	34	5.03	7
1979	395.78	336	387	9	5.30	2
1980	1,489.70	1,252	1,441	49	5.58	9
1981	1,156.83	962	1,107	50	5.89	8
1982	1,410.00	1,233	1,410			
1983	4,310.08	3,728	4,291	19	6.16	3
1984	3,348.16	2,875	3,310	39	6.34	6
1985	3,634.15	3,080	3,546	89	6.75	13
1986	5,292.73	4,443	5,115	178	6.98	26
1987	1,466.52	1,213	1,396	70	7.42	9
1988	1,617.48	1,317	1,516	101	7.87	13
1989	7,215.84	5,777	6,650	566	8.34	68
1990	11,462.74	9,053	10,421	1,041	8.65	120
1991	14,888.28	11,537	13,281	1,608	9.15	176
1992	14,350.24	10,898	12,545	1,805	9.66	187
1993	10,561.54	7,851	9,038	1,524	10.18	150

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1994	9,905.10	7,199	8,287	1,618	10.71	151
1995	3,879.74	2,763	3,181	699	11.11	63
1996	7,818.56	5,428	6,248	1,570	11.67	135
	140,637.24	114,068	129,565	11,072		1,147

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.7 0.82

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371.1 TESTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 20-R3						
NET SALVAGE PERCENT.. 0						
1983	15,664.23	15,664	15,664			
1984	11,125.29	11,125	11,125			
1986	4,384.63	4,385	4,385			
1987	38,021.86	38,022	38,022			
1991	11,962.90	11,795	11,963			
1992	2,199.99	2,154	2,200			
1993	1,383.30	1,338	1,383			
1996	24,385.78	22,942	24,386			
1997	494.25	459	494			
2015	100,388.74	39,905	42,940	57,449	11.37	5,053
	210,010.97	147,789	152,562	57,449		5,053

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.4   2.41

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1904	298.00	290	298			
1905	222.17	216	222			
1930	410.41	363	410			
1931	548.08	483	548			
1932	10,677.87	9,359	10,678			
1933	38.71	34	39			
1934	55.00	48	55			
1935	123.52	107	123			
1936	533.10	458	528	5	10.53	
1937	100.54	86	99	1	10.87	
1938	223.29	190	219	4	11.22	
1939	178.56	151	174	4	11.59	
1940	285.78	240	277	9	11.96	1
1941	249.96	209	241	9	12.34	1
1942	57.82	48	55	2	12.74	
1943	19.44	16	18	1	13.14	
1945	36.92	30	35	2	14.00	
1946	59.80	48	55	4	14.44	
1947	160.11	128	148	12	14.90	1
1948	235.63	187	216	20	15.37	1
1949	51.03	40	46	5	15.85	
1950	2,077.70	1,625	1,875	203	16.35	12
1951	1,726.56	1,339	1,545	182	16.85	11
1952	360.18	277	320	41	17.37	2
1953	287.05	219	253	34	17.91	2
1954	1,145.40	864	997	148	18.45	8
1955	877.98	655	756	122	19.01	6
1956	3,133.21	2,315	2,671	462	19.58	24
1957	1,794.30	1,312	1,514	280	20.16	14
1958	5,277.55	3,817	4,404	873	20.75	42
1959	1,136.57	813	938	198	21.36	9
1960	1,431.64	1,012	1,168	264	21.98	12
1961	1,139.60	796	918	221	22.60	10
1962	1,739.80	1,201	1,386	354	23.24	15
1963	534.64	364	420	115	23.89	5
1964	1,024.78	689	795	230	24.55	9
1965	2,424.42	1,609	1,857	568	25.22	23
1966	1,904.74	1,247	1,439	466	25.89	18
1967	14,200.26	9,168	10,579	3,622	26.58	136
1968	36,083.66	22,959	26,491	9,592	27.28	352
1969	18,362.30	11,512	13,283	5,079	27.98	182
1970	11,282.03	6,965	8,037	3,245	28.70	113

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1971	6,080.40	3,695	4,263	1,817	29.42	62
1972	15,534.05	9,289	10,718	4,816	30.15	160
1973	18,498.57	10,880	12,554	5,945	30.89	192
1974	38,364.70	22,180	25,593	12,772	31.64	404
1975	49,272.90	27,993	32,300	16,973	32.39	524
1976	37,863.68	21,128	24,379	13,485	33.15	407
1977	13,898.67	7,613	8,784	5,114	33.92	151
1978	19,181.60	10,307	11,893	7,289	34.70	210
1979	24,833.70	13,082	15,095	9,739	35.49	274
1980	27,735.34	14,319	16,522	11,213	36.28	309
1981	38,526.40	19,479	22,476	16,050	37.08	433
1982	41,644.61	22,771	26,274	15,370	33.57	458
1983	29,660.39	15,815	18,248	11,412	34.58	330
1984	47,020.30	24,620	28,408	18,612	35.03	531
1985	51,245.11	26,135	30,156	21,089	36.03	585
1986	70,214.20	35,107	40,508	29,706	36.50	814
1987	74,675.20	36,322	41,910	32,765	37.49	874
1988	61,590.79	29,323	33,835	27,756	37.96	731
1989	64,488.00	29,813	34,400	30,088	38.96	772
1990	63,293.80	28,596	32,996	30,298	39.44	768
1991	76,971.45	33,944	39,167	37,805	39.93	947
1992	69,790.71	29,801	34,386	35,405	40.93	865
1993	74,877.76	31,149	35,941	38,936	41.42	940
1994	94,389.03	37,926	43,761	50,628	42.43	1,193
1995	63,758.76	24,898	28,729	35,030	42.92	816
1996	64,141.55	24,136	27,849	36,292	43.92	826
1997	72,745.02	26,523	30,604	42,141	44.43	948
1998	147,067.21	51,532	59,461	87,607	45.43	1,928
1999	227,532.44	76,997	88,843	138,689	45.94	3,019
2000	113,292.57	36,707	42,355	70,938	46.94	1,511
2001	143,018.46	44,279	51,092	91,927	47.94	1,918
2002	79,103.65	23,510	27,127	51,976	48.47	1,072
2003	48,457.78	13,704	15,812	32,645	49.46	660
2004	457,077.76	123,457	142,452	314,626	49.99	6,294
2005	156,879.83	40,083	46,250	110,630	50.99	2,170
2006	18,899.98	4,585	5,290	13,610	51.52	264
2007	23,188.64	5,282	6,095	17,094	52.53	325
2008	111,323.88	23,890	27,566	83,758	53.07	1,578
2009	31,652.25	6,324	7,297	24,355	54.07	450
2010	18,984.06	3,535	4,079	14,905	54.62	273
2011	16,496.41	2,827	3,262	13,234	55.61	238
2012	11,716.78	1,833	2,115	9,602	56.62	170

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
2013	7,230.17	1,030	1,188	6,042	57.17	106
2014	96,772.18	12,338	14,236	82,536	58.17	1,419
2015	3,854.69	436	503	3,352	58.73	57
2016	108,433.77	10,648	12,286	96,148	59.72	1,610
2017	1,733.31	145	167	1,566	60.29	26
2018	88,813.28	6,110	7,050	81,763	60.86	1,343
2019	734.26	39	45	689	61.86	11
2020	180,290.57	6,941	8,009	172,282	62.44	2,759
2021	19,208.11	449	518	18,690	62.60	299
	3,544,568.84	1,197,014	1,380,979	2,163,590		46,033

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.0 1.30

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1849	2,794.87	2,795	2,795			
1867	72.39	72	72			
1888	4,192.87	4,193	4,193			
1897	178.89	179	179			
1898	159.45	159	159			
1902	1,745.39	1,745	1,745			
1905	1,321.50	1,322	1,322			
1906	2,135.22	2,135	2,135			
1908	880.43	880	880			
1909	1,063.58	1,064	1,064			
1910	681.05	681	681			
1912	356.78	357	357			
1916	122.09	122	122			
1917	5,254.50	5,254	5,255			
1918	4,743.98	4,744	4,744			
1919	2,219.29	2,219	2,219			
1920	2,532.43	2,532	2,532			
1921	17,407.66	17,408	17,408			
1922	1,544.59	1,545	1,545			
1923	444.90	443	445			
1924	49,481.98	48,928	49,482			
1925	9,550.78	9,377	9,551			
1926	1,437.54	1,401	1,438			
1927	12,634.65	12,228	12,635			
1928	169.18	163	169			
1929	1,786.94	1,705	1,787			
1930	6,130.68	5,808	6,131			
1931	886.67	834	887			
1932	690.68	645	691			
1933	4,845.58	4,493	4,846			
1934	599.15	551	599			
1937	206.12	186	206			
1939	941.28	835	941			
1941	1,497.83	1,309	1,492	6	6.32	1
1942	1,321.59	1,146	1,306	15	6.66	2
1943	3,799.03	3,267	3,723	76	7.00	11
1944	480.46	410	467	13	7.34	2
1945	7,388.06	6,253	7,127	261	7.68	34
1946	24,241.93	20,354	23,198	1,044	8.02	130
1947	1,212.46	1,010	1,151	61	8.36	7
1948	11,813.70	9,758	11,121	692	8.70	80
1949	155,416.10	127,286	145,070	10,346	9.05	1,143

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1950	314,773.72	255,596	291,308	23,466	9.40	2,496
1951	117,565.93	94,641	107,864	9,702	9.75	995
1952	14,011.46	11,181	12,743	1,268	10.10	126
1953	64,035.02	50,652	57,729	6,306	10.45	603
1954	82,747.60	64,858	73,920	8,828	10.81	817
1955	21,708.32	16,859	19,215	2,494	11.17	223
1956	33,265.27	25,594	29,170	4,095	11.53	355
1957	17,019.75	12,972	14,784	2,235	11.89	188
1958	16,398.95	12,378	14,107	2,291	12.26	187
1959	36,119.98	26,996	30,768	5,352	12.63	424
1960	28,812.28	21,321	24,300	4,512	13.00	347
1961	30,404.90	22,269	25,380	5,024	13.38	375
1962	27,753.65	20,116	22,927	4,827	13.76	351
1963	14,913.85	10,696	12,190	2,723	14.14	193
1964	4,880.13	3,463	3,947	933	14.52	64
1965	18,536.25	13,009	14,827	3,710	14.91	249
1966	5,038.93	3,496	3,984	1,054	15.31	69
1967	4,718.58	3,237	3,689	1,029	15.70	66
1968	4,278.86	2,900	3,305	974	16.11	60
1969	8,771.59	5,875	6,696	2,076	16.51	126
1970	5,741.53	3,799	4,330	1,412	16.92	83
1971	36,049.81	23,548	26,838	9,212	17.34	531
1973	11,871.49	7,555	8,611	3,261	18.18	179
1974	25,525.37	16,025	18,264	7,261	18.61	390
1975	87,663.74	54,281	61,865	25,799	19.04	1,355
1976	4,598.73	2,807	3,199	1,400	19.48	72
1977	8,040.17	4,835	5,511	2,530	19.93	127
1978	13,389.00	7,932	9,040	4,349	20.38	213
1979	6,024.51	3,515	4,006	2,018	20.83	97
1980	2,625.97	1,508	1,719	907	21.29	43
1981	3,896.41	2,201	2,509	1,388	21.76	64
1982	4,195.18	2,854	3,253	942	19.02	50
1984	107,312.77	71,063	80,992	26,321	19.64	1,340
1985	3,250.91	2,109	2,404	847	20.30	42
1987	11,800.00	7,456	8,498	3,302	20.68	160
1989	18,115.32	11,045	12,588	5,527	21.45	258
1990	3,722.71	2,226	2,537	1,186	21.85	54
1993	4,421.64	2,491	2,839	1,583	22.86	69
1995	3,605.96	1,934	2,204	1,402	23.78	59
1996	28,053.64	14,720	16,777	11,277	24.01	470
1998	37,254.30	18,530	21,119	16,135	24.76	652
1999	24,770.91	11,935	13,603	11,168	25.28	442

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2000	23,959.75	11,213	12,780	11,180	25.58	437
2001	34,304.98	15,561	17,735	16,570	25.90	640
2002	6,262.15	2,734	3,116	3,146	26.45	119
2003	8,507.00	3,583	4,084	4,423	26.80	165
2004	14,150.50	5,734	6,535	7,615	27.16	280
2005	14,063.28	5,464	6,227	7,836	27.55	284
2006	17,523.06	6,505	7,414	10,109	27.95	362
2007	55,195.64	19,506	22,231	32,964	28.36	1,162
2008	20,558.92	6,887	7,849	12,710	28.79	441
2011	27,987.49	7,758	8,842	19,146	29.99	638
2013	103,921.61	24,484	27,905	76,017	30.82	2,466
2014	188,343.09	40,343	45,980	142,363	31.18	4,566
2019	56,478.77	5,399	6,153	50,325	33.13	1,519
2020	20,252.13	1,408	1,605	18,647	33.47	557
2021	8,253.67	350	399	7,855	33.84	232
	2,263,831.38	1,417,203	1,598,283	665,548		30,342
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1901	435.33	435	435			
1914	47.48	47	47			
1922	4,142.29	4,142	4,142			
1927	2,693.18	2,606	2,693			
1930	189.29	179	189			
1933	847.72	786	848			
1936	544.45	494	544			
1938	32.84	29	33			
1952	9,309.40	7,429	9,309			
1956	5,775.22	4,443	5,601	174	11.53	15
1957	65,555.21	49,966	62,990	2,565	11.89	216
1958	3,928.05	2,965	3,738	190	12.26	15
1959	1,740.26	1,301	1,640	100	12.63	8
1960	10,837.04	8,019	10,109	728	13.00	56
1961	15,330.33	11,228	14,155	1,176	13.38	88
1962	44,412.35	32,190	40,581	3,832	13.76	278
1963	61,579.91	44,165	55,677	5,903	14.14	417
1964	33,613.04	23,852	30,069	3,544	14.52	244
1965	24,530.54	17,216	21,703	2,827	14.91	190

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1966	16,505.84	11,452	14,437	2,069	15.31	135
1967	43,814.66	30,057	37,892	5,923	15.70	377
1968	27,948.53	18,944	23,882	4,067	16.11	252
1969	34,014.41	22,783	28,722	5,293	16.51	321
1970	109,477.63	72,430	91,309	18,168	16.92	1,074
1971	28,682.10	18,735	23,618	5,064	17.34	292
1972	14,929.02	9,629	12,139	2,790	17.75	157
1973	43,388.65	27,613	34,811	8,578	18.18	472
1974	6,679.10	4,193	5,286	1,393	18.61	75
1975	2,388.78	1,479	1,865	524	19.04	28
1976	325.75	199	251	75	19.48	4
1977	310.42	187	236	75	19.93	4
1978	5,350.19	3,169	3,995	1,355	20.38	66
1979	1,782.45	1,040	1,311	471	20.83	23
1980	6,278.95	3,605	4,545	1,734	21.29	81
1981	51,214.65	28,926	36,466	14,749	21.76	678
1982	55,560.11	37,803	47,657	7,903	19.02	416
1983	28,861.79	19,381	24,433	4,429	19.32	229
1984	5,806.34	3,845	4,847	959	19.64	49
1985	10,388.00	6,740	8,497	1,891	20.30	93
1986	10,162.46	6,492	8,184	1,978	20.64	96
1987	22,171.50	14,010	17,662	4,510	20.68	218
1988	9,500.30	5,900	7,438	2,062	21.06	98
1989	21,764.75	13,270	16,729	5,036	21.45	235
1990	17,697.49	10,583	13,342	4,356	21.85	199
1991	2,527.62	1,481	1,867	661	22.26	30
1992	778.74	447	564	215	22.69	9
1993	14,187.04	7,993	10,076	4,111	22.86	180
1994	30,706.90	16,889	21,291	9,416	23.32	404
1995	14,521.42	7,786	9,815	4,706	23.78	198
1996	64,620.77	33,907	42,745	21,876	24.01	911
1997	90,222.73	46,014	58,008	32,215	24.50	1,315
1998	90,466.61	44,998	56,727	33,740	24.76	1,363
1999	26,987.42	13,003	16,392	10,595	25.28	419
2000	22,242.63	10,410	13,123	9,119	25.58	356
2001	27,792.71	12,607	15,893	11,900	25.90	459
2002	74,704.50	32,616	41,118	33,587	26.45	1,270
2003	35,723.93	15,047	18,969	16,755	26.80	625
2004	12,600.58	5,106	6,437	6,164	27.16	227
2005	1,094.30	425	536	559	27.55	20
2006	2,275.29	845	1,065	1,210	27.95	43
2007	50,329.62	17,786	22,422	27,908	28.36	984

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2008	4,380.00	1,467	1,849	2,531	28.79	88
2009	6,511.91	2,066	2,605	3,907	29.06	134
2010	2,023.74	602	759	1,265	29.52	43
2014	1,151,949.73	246,748	311,065	840,885	31.18	26,969
2017	18,705.63	2,716	3,424	15,282	32.38	472
2019	87,261.18	8,342	10,516	76,745	33.13	2,316
2020	35,549.59	2,471	3,115	32,435	33.47	969
	2,728,712.39	1,115,729	1,404,439	1,324,273		47,003
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1862	16.00	16	16			
1901	123.38	123	123			
1903	2,860.00	2,860	2,860			
1909	2,901.80	2,902	2,902			
1911	7,556.70	7,557	7,557			
1916	161.12	161	161			
1924	266.11	263	266			
1926	212.80	207	213			
1928	13,724.13	13,189	13,724			
1929	894.16	853	894			
1931	38.28	36	38			
1937	572.62	516	573			
1938	4,600.60	4,111	4,601			
1946	12.36	10	12			
1948	432.79	357	433			
1949	6,857.71	5,616	6,858			
1950	1,464.38	1,189	1,464			
1951	23,781.96	19,144	23,782			
1953	8.07	6	8			
1954	1,809.10	1,418	1,809			
1955	0.60			1	11.17	
1956	768.66	591	769			
1957	123.78	94	124			
1958	1,865.14	1,408	1,852	13	12.26	1
1960	2,255.90	1,669	2,195	61	13.00	5
1961	2,692.32	1,972	2,594	99	13.38	7
1962	2,889.36	2,094	2,754	135	13.76	10

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1963	2,147.00	1,540	2,025	122	14.14	9
1964	1,552.28	1,101	1,448	104	14.52	7
1965	251.74	177	233	19	14.91	1
1966	898.68	624	821	78	15.31	5
1967	2,957.44	2,029	2,669	289	15.70	18
1968	6,310.72	4,277	5,625	685	16.11	43
1969	8,455.01	5,663	7,448	1,007	16.51	61
1970	1,245.94	824	1,084	162	16.92	10
1971	15,473.04	10,107	13,293	2,180	17.34	126
1972	1,369.67	883	1,161	208	17.75	12
1973	1,726.18	1,099	1,445	281	18.18	15
1974	486.52	305	401	85	18.61	5
1975	909.12	563	740	169	19.04	9
1976	1,641.93	1,002	1,318	324	19.48	17
1978	1,522.09	902	1,186	336	20.38	16
1981	1,579.82	892	1,173	407	21.76	19
1985	1,166.22	757	996	171	20.30	8
1986	57,181.74	36,528	48,043	9,139	20.64	443
1987	5,760.94	3,640	4,787	973	20.68	47
1989	3,798.31	2,316	3,046	752	21.45	35
1990	1,768.35	1,057	1,390	378	21.85	17
1991	2,041.00	1,196	1,573	468	22.26	21
1992	2,626.45	1,506	1,981	646	22.69	28
1995	422.40	226	297	125	23.78	5
1996	825.00	433	569	256	24.01	11
1997	2,848.85	1,453	1,911	938	24.50	38
1998	2,075.00	1,032	1,357	718	24.76	29
2003	2,542.54	1,071	1,409	1,134	26.80	42
2005	5,268.60	2,047	2,692	2,576	27.55	94
2006	3,944.55	1,464	1,926	2,019	27.95	72
2007	1,852.48	655	861	991	28.36	35
2011	2,856.60	792	1,042	1,815	29.99	61
2012	17,301.02	4,450	5,853	11,448	30.32	378
2016	21,621.02	3,654	4,806	16,815	31.96	526
2017	68,032.91	9,878	12,992	55,041	32.38	1,700

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2018	210,544.81	25,392	33,397	177,148	32.81	5,399
2020	11,411.86	793	1,043	10,369	33.47	310
2021	8,525.00	361	475	8,050	33.84	238
	561,832.66	201,051	253,099	308,734		9,933
	5,554,376.43	2,733,983	3,255,821	2,298,555		87,278

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.3 1.57

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1924	117,571.16	102,996	109,463	8,108	9.05	896
1925	19,800.70	17,278	18,363	1,438	9.30	155
1926	327,198.12	284,440	302,301	24,897	9.54	2,610
1927	31,359.10	27,154	28,859	2,500	9.79	255
1928	128,058.00	110,428	117,362	10,696	10.05	1,064
1929	141,368.72	121,403	129,026	12,342	10.31	1,197
1930	317,243.29	271,310	288,347	28,897	10.57	2,734
1931	181,921.52	154,908	164,635	17,286	10.84	1,595
1932	18,290.56	15,504	16,478	1,813	11.12	163
1933	10,354.34	8,737	9,286	1,069	11.40	94
1934	20,618.76	17,317	18,404	2,214	11.69	189
1935	14,661.59	12,253	13,022	1,639	11.99	137
1936	7,204.47	5,991	6,367	837	12.30	68
1937	10,422.89	8,622	9,163	1,259	12.61	100
1938	7,840.11	6,450	6,855	985	12.94	76
1939	20,686.92	16,926	17,989	2,698	13.27	203
1940	20,301.69	16,517	17,554	2,748	13.61	202
1941	30,987.66	25,058	26,631	4,356	13.97	312
1942	29,019.48	23,323	24,788	4,232	14.33	295
1943	4,262.57	3,404	3,618	645	14.71	44
1944	5,525.61	4,383	4,658	867	15.10	57
1945	9,691.56	7,634	8,113	1,578	15.50	102
1946	356,998.33	279,191	296,722	60,276	15.91	3,789
1947	60,243.26	46,767	49,704	10,540	16.33	645
1948	122,728.43	94,534	100,470	22,258	16.77	1,327
1949	137,234.26	104,862	111,447	25,788	17.22	1,498
1950	1,730,340.32	1,311,511	1,393,865	336,475	17.67	19,042
1951	359,990.17	270,536	287,524	72,466	18.14	3,995
1952	667,601.20	497,223	528,445	139,156	18.63	7,469
1953	741,524.27	547,304	581,671	159,853	19.12	8,361
1954	1,389,720.92	1,016,025	1,079,825	309,896	19.63	15,787
1955	1,192,201.82	863,118	917,316	274,886	20.15	13,642
1956	1,778,586.11	1,274,730	1,354,775	423,811	20.68	20,494
1957	1,512,458.82	1,072,817	1,140,183	372,276	21.22	17,544
1958	3,014,210.21	2,115,312	2,248,140	766,070	21.77	35,189
1959	1,810,011.78	1,256,347	1,335,237	474,774	22.33	21,262
1960	2,919,433.23	2,003,198	2,128,986	790,447	22.91	34,502
1961	1,730,998.94	1,173,998	1,247,717	483,281	23.49	20,574
1962	1,885,991.43	1,263,614	1,342,961	543,031	24.09	22,542
1963	2,309,279.58	1,528,235	1,624,198	685,081	24.69	27,747
1964	2,274,337.44	1,485,802	1,579,101	695,237	25.31	27,469
1965	2,877,640.64	1,855,474	1,971,986	905,655	25.93	34,927

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1966	3,010,623.56	1,915,238	2,035,503	975,121	26.56	36,714
1967	3,183,527.04	1,996,899	2,122,291	1,061,236	27.21	39,002
1968	3,575,028.13	2,210,654	2,349,469	1,225,559	27.86	43,990
1969	3,950,839.39	2,407,325	2,558,489	1,392,350	28.52	48,820
1970	3,335,439.99	2,001,731	2,127,427	1,208,013	29.19	41,384
1971	3,165,425.05	1,870,196	1,987,632	1,177,793	29.87	39,431
1972	3,069,858.98	1,785,154	1,897,250	1,172,609	30.55	38,383
1973	2,865,864.17	1,639,418	1,742,363	1,123,501	31.24	35,964
1974	3,100,807.41	1,743,677	1,853,169	1,247,639	31.95	39,050
1975	2,234,563.29	1,235,133	1,312,691	921,872	32.65	28,235
1976	1,977,182.62	1,073,373	1,140,774	836,409	33.37	25,065
1977	2,480,072.76	1,321,581	1,404,568	1,075,505	34.10	31,540
1978	2,362,710.10	1,235,414	1,312,990	1,049,720	34.83	30,138
1979	4,439,600.77	2,276,982	2,419,962	2,019,639	35.56	56,795
1980	9,369,751.94	4,709,237	5,004,947	4,364,805	36.31	120,209
1981	6,464,961.75	3,182,895	3,382,760	3,082,202	37.06	83,168
1982	6,936,270.59	3,820,498	4,060,401	2,875,870	33.03	87,068
1983	1,658,802.90	897,744	954,117	704,686	33.49	21,042
1984	2,318,429.39	1,222,740	1,299,520	1,018,909	34.50	29,534
1985	3,039,180.05	1,572,776	1,671,536	1,367,644	34.96	39,120
1986	4,863,918.39	2,467,952	2,622,923	2,240,995	35.44	63,233
1987	2,064,058.88	1,018,407	1,082,356	981,703	36.45	26,933
1988	4,171,695.45	2,014,929	2,141,453	2,030,242	36.93	54,975
1989	3,555,762.97	1,679,742	1,785,219	1,770,544	37.42	47,315
1990	3,311,108.41	1,517,150	1,612,417	1,698,691	38.43	44,202
1991	3,115,957.41	1,393,768	1,481,288	1,634,670	38.92	42,001
1992	2,423,898.39	1,057,304	1,123,696	1,300,203	39.43	32,975
1993	1,063,584.25	451,811	480,182	583,402	39.94	14,607
1994	867,827.63	356,156	378,520	489,307	40.94	11,952
1995	5,074,747.21	2,023,809	2,150,891	2,923,856	41.46	70,522
1996	4,984,833.22	1,928,632	2,049,738	2,935,096	41.99	69,900
1997	1,933,305.11	719,769	764,966	1,168,339	42.99	27,177
1998	2,319,366.82	835,436	887,896	1,431,471	43.52	32,892
1999	1,116,076.65	388,171	412,546	703,531	44.07	15,964
2000	2,569,138.76	861,175	915,251	1,653,888	44.62	37,066
2001	5,869,358.33	1,880,542	1,998,628	3,870,730	45.61	84,866
2002	1,049,656.52	322,769	343,037	706,620	46.17	15,305
2003	3,324,609.45	978,765	1,040,225	2,284,384	46.73	48,885
2004	1,756,382.94	493,895	524,908	1,231,475	47.29	26,041
2005	1,026,274.87	274,836	292,094	734,181	47.86	15,340
2006	2,689,388.61	678,802	721,426	1,967,962	48.86	40,278
2007	918,972.70	219,359	233,133	685,839	49.44	13,872

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
2008	2,253,044.55	506,484	538,288	1,714,757	50.01	34,288
2009	2,518,614.96	530,420	563,727	1,954,888	50.60	38,634
2010	2,200,572.12	431,752	458,863	1,741,709	51.20	34,018
2011	1,838,526.20	334,060	355,037	1,483,489	51.79	28,644
2012	2,621,357.99	437,767	465,256	2,156,102	52.39	41,155
2013	3,403,370.04	517,312	549,796	2,853,574	53.00	53,841
2014	4,918,603.37	672,865	715,117	4,203,487	53.61	78,409
2015	9,555,095.16	1,167,633	1,240,953	8,314,142	53.85	154,394
2016	12,496,511.71	1,332,128	1,415,777	11,080,735	54.48	203,391
2017	23,576,599.91	2,152,544	2,287,710	21,288,890	54.74	388,909
2018	19,147,932.48	1,439,925	1,530,343	17,617,590	55.38	318,122
2019	10,719,011.45	637,781	677,830	10,041,182	55.32	181,511
2020	11,038,834.41	474,670	504,476	10,534,358	55.64	189,331
2021	24,801,847.07	659,729	701,156	24,100,691	54.99	438,274
2022	2,154,307.08	20,250	21,522	2,132,786	52.97	40,264
	296,199,011.33	96,319,798	102,368,057	193,830,954		4,324,491
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1901	2,776.38	2,635	2,442	335	3.72	90
1903	551.17	519	481	70	4.26	16
1904	357.52	335	310	47	4.51	10
1905	1,653.59	1,546	1,433	221	4.76	46
1906	4,401.21	4,100	3,799	602	4.99	121
1907	11,495.59	10,674	9,891	1,604	5.22	307
1908	23,450.30	21,700	20,109	3,341	5.45	613
1909	466.21	430	398	68	5.67	12
1910	9,208.74	8,466	7,845	1,364	5.89	232
1911	1,083.10	992	919	164	6.11	27
1912	1,090.39	996	923	167	6.32	26
1913	2,412.15	2,196	2,035	377	6.54	58
1914	451.09	409	379	72	6.76	11
1915	191.97	174	161	31	6.98	4
1916	301.96	272	252	50	7.20	7
1917	305.97	275	255	51	7.42	7
1918	1,469.78	1,316	1,220	250	7.65	33
1919	3,172.90	2,830	2,622	550	7.88	70
1920	8,457.54	7,518	6,967	1,491	8.11	184

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1921	43,430.06	38,468	35,647	7,783	8.34	933
1922	27,793.14	24,527	22,729	5,065	8.58	590
1923	42,465.98	37,341	34,603	7,863	8.81	893
1924	49,641.94	43,488	40,299	9,343	9.05	1,032
1925	49,217.85	42,947	39,798	9,420	9.30	1,013
1926	13,967.43	12,142	11,252	2,716	9.54	285
1927	37,697.15	32,642	30,249	7,449	9.79	761
1928	10,586.07	9,129	8,460	2,126	10.05	212
1929	2,657.26	2,282	2,115	543	10.31	53
1930	107,214.55	91,691	84,968	22,247	10.57	2,105
1931	237,410.22	202,157	187,334	50,076	10.84	4,620
1932	7,106.30	6,024	5,582	1,524	11.12	137
1933	12,543.49	10,585	9,809	2,735	11.40	240
1934	2,764.56	2,322	2,152	613	11.69	52
1935	3,019.47	2,524	2,339	681	11.99	57
1936	21,786.11	18,115	16,787	4,999	12.30	406
1937	4,383.12	3,626	3,360	1,023	12.61	81
1938	3,637.64	2,993	2,774	864	12.94	67
1939	2,654.94	2,172	2,013	642	13.27	48
1940	12,659.51	10,299	9,544	3,116	13.61	229
1941	6,163.32	4,984	4,619	1,545	13.97	111
1942	5,175.94	4,160	3,855	1,321	14.33	92
1943	1,871.50	1,494	1,384	487	14.71	33
1944	2,362.95	1,874	1,737	626	15.10	41
1945	1,900.42	1,497	1,387	513	15.50	33
1946	74,463.46	58,234	53,964	20,499	15.91	1,288
1947	15,106.46	11,727	10,867	4,239	16.33	260
1948	8,573.89	6,604	6,120	2,454	16.77	146
1949	15,122.62	11,555	10,708	4,415	17.22	256
1950	9,186.36	6,963	6,452	2,734	17.67	155
1951	14,592.87	10,967	10,163	4,430	18.14	244
1952	177,727.06	132,369	122,663	55,064	18.63	2,956
1953	423,119.54	312,296	289,397	133,722	19.12	6,994
1954	7,591.01	5,550	5,143	2,448	19.63	125
1955	105,136.66	76,116	70,535	34,602	20.15	1,717
1956	634,874.34	455,021	421,657	213,217	20.68	10,310
1957	1,597,876.93	1,133,406	1,050,300	547,577	21.22	25,805
1958	178,022.84	124,933	115,772	62,250	21.77	2,859
1959	1,139,785.85	791,137	733,128	406,658	22.33	18,211
1960	636,481.45	436,728	404,705	231,776	22.91	10,117
1961	1,292,444.90	876,562	812,289	480,156	23.49	20,441
1962	1,015,841.47	680,614	630,709	385,133	24.09	15,987

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

PNG
SURVIVOR CURVE.. IOWA 73-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1963	1,795,714.00	1,188,368	1,101,232	694,482	24.69	28,128
1964	2,989,125.04	1,952,765	1,809,580	1,179,545	25.31	46,604
1965	2,317,555.85	1,494,337	1,384,766	932,790	25.93	35,973
1966	2,080,836.35	1,323,745	1,226,682	854,154	26.56	32,159
1967	2,239,324.71	1,404,639	1,301,645	937,680	27.21	34,461
1968	3,357,767.61	2,076,309	1,924,065	1,433,702	27.86	51,461
1969	3,066,668.06	1,868,582	1,731,570	1,335,098	28.52	46,813
1970	2,482,727.08	1,489,984	1,380,732	1,101,995	29.19	37,752
1971	2,268,488.38	1,340,268	1,241,994	1,026,494	29.87	34,365
1972	3,297,353.95	1,917,444	1,776,849	1,520,505	30.55	49,771
1973	1,215,319.47	695,224	644,247	571,072	31.24	18,280
1974	545,018.45	306,480	284,008	261,011	31.95	8,169
1975	614,921.50	339,892	314,970	299,952	32.65	9,187
1976	409,372.36	222,240	205,944	203,428	33.37	6,096
1977	611,485.62	325,848	301,955	309,530	34.10	9,077
1978	580,270.32	303,412	281,165	299,106	34.83	8,588
1979	1,015,149.65	520,650	482,474	532,676	35.56	14,980
1980	1,098,282.05	551,997	511,522	586,760	36.31	16,160
1981	3,055,776.18	1,504,450	1,394,137	1,661,639	37.06	44,836
1982	4,832,870.81	2,661,945	2,466,760	2,366,111	33.03	71,635
1983	851,728.59	460,956	427,157	424,572	33.49	12,678
1984	1,857,907.52	979,860	908,013	949,895	34.50	27,533
1985	1,833,018.39	948,587	879,033	953,986	34.96	27,288
1986	1,670,976.65	847,854	785,686	885,291	35.44	24,980
1987	2,023,205.07	998,249	925,053	1,098,152	36.45	30,128
1988	1,973,736.88	953,315	883,414	1,090,323	36.93	29,524
1989	1,595,844.68	753,877	698,600	897,245	37.42	23,978
1990	1,292,105.03	592,043	548,632	743,473	38.43	19,346
1991	833,707.70	372,917	345,573	488,135	38.92	12,542
1992	2,818,317.93	1,229,350	1,139,209	1,679,109	39.43	42,585
1993	859,068.96	364,932	338,174	520,895	39.94	13,042
1994	1,534,802.96	629,883	583,697	951,106	40.94	23,232
1995	1,210,085.12	482,582	447,197	762,888	41.46	18,401
1996	8,877,962.49	3,434,884	3,183,024	5,694,939	41.99	135,626
1997	7,741,263.69	2,882,072	2,670,746	5,070,517	42.99	117,946
1998	3,546,575.35	1,277,476	1,183,806	2,362,769	43.52	54,292
1999	442,609.80	153,940	142,652	299,957	44.07	6,806
2000	8,085,781.31	2,710,354	2,511,620	5,574,162	44.62	124,925
2001	2,153,091.68	689,851	639,268	1,513,823	45.61	33,191
2002	5,045,522.89	1,551,498	1,437,736	3,607,787	46.17	78,141
2003	1,732,337.82	510,000	472,605	1,259,733	46.73	26,958
2004	2,012,716.84	565,976	524,476	1,488,241	47.29	31,471

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
2005	2,723,450.38	729,340	675,862	2,047,589	47.86	42,783
2006	1,310,986.92	330,893	306,631	1,004,356	48.86	20,556
2007	913,985.03	218,168	202,171	711,814	49.44	14,398
2008	2,762,741.08	621,064	575,525	2,187,216	50.01	43,736
2009	546,773.93	115,151	106,708	440,066	50.60	8,697
2010	2,403,355.65	471,538	436,963	1,966,393	51.20	38,406
2011	1,323,280.74	240,440	222,810	1,100,471	51.79	21,249
2012	2,645,827.17	441,853	409,454	2,236,373	52.39	42,687
2013	4,758,784.25	723,335	670,297	4,088,487	53.00	77,141
2014	15,721,513.58	2,150,703	1,993,004	13,728,509	53.61	256,081
2015	16,761,300.12	2,048,231	1,898,046	14,863,254	53.85	276,012
2016	11,976,625.36	1,276,708	1,183,094	10,793,531	54.48	198,119
2017	7,148,999.24	652,704	604,845	6,544,154	54.74	119,550
2018	61,134,032.76	4,597,279	4,260,187	56,873,845	55.38	1,026,974
2019	7,636,254.30	454,357	421,042	7,215,213	55.32	130,427
2020	8,964,217.77	385,461	357,197	8,607,020	55.64	154,691
2021	2,992,916.89	79,612	73,775	2,919,142	54.99	53,085
2022	2,280,710.65	21,439	19,867	2,260,844	52.97	42,682
	262,001,506.80	68,244,959	63,240,954	198,760,553		4,220,251
CPG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1903	540.00	508	540			
1904	277.35	260	277			
1905	16.97	16	17			
1906	175.06	163	175			
1908	16.89	16	17			
1909	59.21	55	59			
1910	473.21	435	473			
1911	4.15	4	4			
1912	75.33	69	75			
1913	939.15	855	939			
1915	258.28	234	258			
1916	85.24	77	85			
1918	99.76	89	100			
1919	146.01	130	146			
1921	55.11	49	55			
1923	9,498.38	8,352	9,377	121	8.81	14

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

CPG
SURVIVOR CURVE.. IOWA 73-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1924	1,058.00	927	1,041	17	9.05	2
1925	6,269.98	5,471	6,143	127	9.30	14
1926	4,571.75	3,974	4,462	110	9.54	12
1927	8,174.36	7,078	7,947	228	9.79	23
1928	26,149.73	22,550	25,318	832	10.05	83
1929	89.92	77	86	3	10.31	
1930	197.07	169	190	7	10.57	1
1931	5.85	5	6			
1932	56,207.31	47,645	53,494	2,714	11.12	244
1933	178.58	151	170	9	11.40	1
1934	13.03	11	12	1	11.69	
1935	88.35	74	83	5	11.99	
1936	601.02	500	561	40	12.30	3
1937	1.18	1	1			
1938	76.96	63	71	6	12.94	
1939	363.28	297	333	30	13.27	2
1940	515.02	419	470	45	13.61	3
1941	420.28	340	382	39	13.97	3
1942	980.48	788	885	96	14.33	7
1944	530.55	421	473	58	15.10	4
1945	860.61	678	761	99	15.50	6
1946	4,399.12	3,440	3,862	537	15.91	34
1947	4,376.05	3,397	3,814	562	16.33	34
1948	2,292.31	1,766	1,983	310	16.77	18
1949	66,744.12	51,000	57,260	9,484	17.22	551
1950	1,038.54	787	884	155	17.67	9
1951	20,218.41	15,194	17,059	3,159	18.14	174
1952	5,371.79	4,001	4,492	880	18.63	47
1953	32,103.51	23,695	26,604	5,500	19.12	288
1954	25,737.28	18,817	21,127	4,610	19.63	235
1955	8,836.05	6,397	7,182	1,654	20.15	82
1956	38,373.56	27,503	30,879	7,494	20.68	362
1957	51,981.85	36,872	41,398	10,584	21.22	499
1958	23,045.84	16,173	18,158	4,888	21.77	225
1959	63,757.25	44,255	49,687	14,070	22.33	630
1960	64,082.77	43,971	49,369	14,714	22.91	642
1961	153,720.00	104,256	117,054	36,666	23.49	1,561
1962	215,901.83	144,654	162,411	53,491	24.09	2,220
1963	473,450.35	313,320	351,781	121,669	24.69	4,928
1964	552,763.87	361,115	405,443	147,321	25.31	5,821
1965	345,133.89	222,539	249,856	95,277	25.93	3,674
1966	750,654.75	477,537	536,156	214,499	26.56	8,076

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

CPG
SURVIVOR CURVE.. IOWA 73-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1967	411,396.20	258,052	289,729	121,667	27.21	4,471
1968	543,727.35	336,219	377,491	166,236	27.86	5,967
1969	464,445.98	282,996	317,735	146,711	28.52	5,144
1970	355,389.21	213,283	239,464	115,925	29.19	3,971
1971	284,632.17	168,166	188,809	95,823	29.87	3,208
1972	158,616.45	92,237	103,559	55,057	30.55	1,802
1973	328,028.38	187,649	210,684	117,345	31.24	3,756
1974	326,954.46	183,856	206,425	120,530	31.95	3,772
1975	118,964.29	65,756	73,828	45,137	32.65	1,382
1976	263,879.78	143,255	160,840	103,040	33.37	3,088
1977	117,577.19	62,655	70,346	47,231	34.10	1,385
1978	357,583.92	186,973	209,925	147,659	34.83	4,239
1979	163,338.99	83,773	94,056	69,283	35.56	1,948
1980	225,997.29	113,586	127,529	98,468	36.31	2,712
1981	259,329.84	127,676	143,349	115,981	37.06	3,130
1982	244,947.29	134,917	151,479	93,469	33.03	2,830
1983	355,618.15	192,461	216,086	139,532	33.49	4,166
1984	139,368.83	73,503	82,526	56,843	34.50	1,648
1985	405,344.87	209,766	235,515	169,829	34.96	4,858
1986	652,341.08	330,998	371,629	280,712	35.44	7,921
1987	152,548.22	75,267	84,506	68,042	36.45	1,867
1988	173,808.20	83,949	94,254	79,554	36.93	2,154
1989	395,413.43	186,793	209,722	185,691	37.42	4,962
1990	89,218.21	40,880	45,898	43,320	38.43	1,127
1991	536,454.71	239,956	269,411	267,043	38.92	6,861
1992	1,308,617.95	570,819	640,889	667,729	39.43	16,935
1993	701,571.16	298,027	334,611	366,960	39.94	9,188
1995	2,001.35	798	896	1,105	41.46	27
1996	514,785.42	199,170	223,619	291,167	41.99	6,934
1997	771,001.14	287,044	322,280	448,722	42.99	10,438
1998	1,033,727.04	372,348	418,055	615,672	43.52	14,147
1999	389,181.56	135,357	151,973	237,209	44.07	5,383
2000	3,613,736.05	1,211,324	1,360,018	2,253,718	44.62	50,509
2001	449,531.96	144,030	161,710	287,822	45.61	6,311
2002	1,550,902.59	476,903	535,444	1,015,458	46.17	21,994
2003	356,816.99	105,047	117,942	238,875	46.73	5,112
2004	4,258,994.42	1,197,629	1,344,642	2,914,353	47.29	61,627
2005	6,360,418.54	1,703,320	1,912,408	4,448,010	47.86	92,938
2006	2,594,946.92	654,965	735,364	1,859,583	48.86	38,059
2007	1,045,151.13	249,478	280,102	765,049	49.44	15,474
2008	168,475.91	37,873	42,522	125,954	50.01	2,519
2009	3,190,353.72	671,888	754,364	2,435,989	50.60	48,142

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
2010	953,450.15	187,067	210,030	743,420	51.20	14,520
2011	2,263,165.55	411,217	461,695	1,801,470	51.79	34,784
2012	504,730.78	84,290	94,637	410,094	52.39	7,828
2013	946,351.29	143,845	161,502	784,849	53.00	14,808
2014	488,691.30	66,853	75,059	413,632	53.61	7,716
2015	2,366,373.85	289,171	324,668	2,041,706	53.85	37,915
2016	9,566,157.00	1,019,752	1,144,930	8,421,227	54.48	154,575
2017	7,610,909.52	694,876	780,174	6,830,735	54.74	124,785
2018	5,201,117.33	391,124	439,136	4,761,982	55.38	85,987
2019	4,082,347.39	242,900	272,717	3,809,631	55.32	68,865
2020	10,222,144.44	439,552	493,508	9,728,636	55.64	174,850
2021	69,953.72	1,861	2,089	67,864	54.99	1,234
2022	687,870.47	6,466	7,260	680,611	52.97	12,849
	83,822,457.68	18,393,256	20,650,987	63,171,471		1,265,354
	642,022,975.81	182,958,013	186,259,998	455,762,978		9,810,096

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.5 1.53

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1917	346.81	325	9-	356	4.00	89
1918	2,471.60	2,317	65-	2,536	4.04	628
1919	10,850.19	10,166	284-	11,134	4.07	2,736
1920	12,844.69	12,026	336-	13,181	4.11	3,207
1921	15,675.37	14,668	410-	16,085	4.14	3,885
1922	36,052.62	33,715	942-	36,994	4.17	8,871
1923	24,079.53	22,505	629-	24,708	4.20	5,883
1924	82,930.84	77,461	2,164-	85,095	4.23	20,117
1925	29,170.31	27,234	761-	29,931	4.25	7,043
1926	57,092.41	53,268	1,488-	58,580	4.28	13,687
1927	37,844.25	35,293	986-	38,830	4.30	9,030
1928	31,086.54	28,972	809-	31,896	4.33	7,366
1929	55,097.15	51,324	1,434-	56,531	4.35	12,996
1930	24,759.46	23,052	644-	25,403	4.37	5,813
1931	4,619.52	4,299	120-	4,740	4.39	1,080
1932	3,304.67	3,073	86-	3,391	4.41	769
1933	164.71	153	4-	169	4.43	38
1934	486.45	452	13-	499	4.45	112
1935	3,798.25	3,527	99-	3,897	4.46	874
1936	6,338.58	5,882	164-	6,503	4.48	1,452
1937	3,450.74	3,200	89-	3,540	4.50	787
1938	3,058.42	2,835	79-	3,138	4.51	696
1939	11,853.17	10,981	307-	12,160	4.53	2,684
1940	7,326.44	6,784	190-	7,516	4.54	1,656
1941	17,368.73	16,073	449-	17,818	4.55	3,916
1942	621.35	575	16-	637	4.57	139
1943	1,161.96	1,074	30-	1,192	4.58	260
1944	3,371.06	3,114	87-	3,458	4.59	753
1945	380.02	351	10-	390	4.61	85
1946	9,325.50	8,601	240-	9,566	4.62	2,071
1947	17,139.31	15,798	441-	17,581	4.63	3,797
1948	30,843.09	28,410	794-	31,637	4.64	6,818
1949	20,421.13	18,796	525-	20,946	4.65	4,505
1950	45,691.07	42,024	1,174-	46,865	4.66	10,057
1951	45,598.38	41,907	1,171-	46,769	4.67	10,015
1952	60,154.79	55,240	1,543-	61,698	4.68	13,183
1953	92,599.39	84,963	2,373-	94,973	4.69	20,250
1954	54,239.30	49,723	1,389-	55,628	4.70	11,836
1955	68,424.30	62,671	1,751-	70,175	4.71	14,899
1956	80,406.41	73,591	2,056-	82,462	4.71	17,508
1957	86,162.19	78,782	2,201-	88,363	4.72	18,721

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1958	69,495.13	63,479	1,773-	71,268	4.73	15,067
1959	76,708.55	69,994	1,955-	78,664	4.74	16,596
1960	6,107.66	5,567	156-	6,263	4.75	1,319
1961	51.47	47	1-	53	4.75	11
1962	3,517.27	3,199	89-	3,607	4.76	758
1968	307.52	278	8-	315	4.80	66
2012	5,999.39	4,088	114-	6,114	4.91	1,245
2015	124.83	75	2-	127	4.92	26
2016	9,527.55	5,425	152-	9,679	4.92	1,967
2019	393,183.77	163,761	4,575-	397,758	4.90	81,175
2020	63,026.26	21,315	595-	63,622	4.89	13,011
	1,726,660.10	1,352,433	37,780-	1,764,440		381,553
PNG						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1910	837.53	790	490	348	3.66	95
1911	7,777.24	7,331	4,545	3,232	3.72	869
1912	4,333.74	4,082	2,531	1,803	3.77	478
1923	258.52	242	150	108	4.20	26
1943	481.31	445	276	205	4.58	45
1952	83,411.73	76,597	47,487	35,925	4.68	7,676
	97,100.07	89,487	55,478	41,622		9,189
	1,823,760.17	1,441,920	17,698	1,806,062		390,742

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.6   21.43

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1972	18,463.36	12,095	11,992	6,472	23.11	280
1973	47,926.87	30,902	30,638	17,289	23.80	726
1974	11,603.34	7,360	7,297	4,306	24.50	176
1975	46,298.14	28,878	28,631	17,667	25.21	701
1976	493,878.08	302,811	300,220	193,658	25.92	7,471
1977	448,111.53	269,871	267,562	180,549	26.65	6,775
1978	668,378.96	395,139	391,759	276,620	27.39	10,099
1979	530,323.05	307,667	305,035	225,288	28.13	8,009
1980	1,139,798.12	648,329	642,783	497,016	28.89	17,204
1981	1,418,433.34	790,720	783,955	634,478	29.65	21,399
1982	2,015,785.94	1,208,262	1,197,925	817,861	27.07	30,213
1983	2,395,453.50	1,400,382	1,388,402	1,007,052	28.07	35,876
1984	3,313,293.29	1,900,505	1,884,246	1,429,047	28.62	49,932
1985	3,455,934.71	1,943,963	1,927,332	1,528,602	29.17	52,403
1986	4,392,980.63	2,405,157	2,384,581	2,008,400	30.17	66,569
1987	7,585,099.16	4,065,613	4,030,832	3,554,267	30.73	115,661
1988	10,758,959.68	5,641,998	5,593,731	5,165,229	31.29	165,076
1989	13,166,807.56	6,749,306	6,691,566	6,475,242	31.86	203,240
1990	14,878,224.87	7,397,453	7,334,168	7,544,057	32.86	229,582
1991	8,974,485.39	4,353,523	4,316,279	4,658,207	33.44	139,300
1992	7,043,063.25	3,329,960	3,301,472	3,741,591	34.01	110,014
1993	5,217,339.82	2,385,368	2,364,961	2,852,379	35.02	81,450
1994	9,420,048.87	4,188,154	4,152,324	5,267,724	35.60	147,970
1995	15,218,159.45	6,571,201	6,514,984	8,703,175	36.19	240,486
1996	9,304,297.11	3,870,588	3,837,475	5,466,822	37.20	146,958
1997	14,070,036.43	5,668,818	5,620,321	8,449,715	37.79	223,597
1998	9,915,843.96	3,838,423	3,805,585	6,110,259	38.79	157,522
1999	10,489,247.26	3,918,783	3,885,258	6,603,989	39.40	167,614
2000	10,935,780.80	3,936,881	3,903,201	7,032,580	40.00	175,814
2001	11,035,662.15	3,796,268	3,763,791	7,271,871	41.00	177,363
2002	10,164,885.10	3,354,412	3,325,715	6,839,170	41.61	164,364
2003	14,319,317.39	4,523,472	4,484,774	9,834,544	42.23	232,881
2004	13,359,758.72	4,003,920	3,969,667	9,390,092	43.23	217,212
2005	14,344,796.14	4,091,136	4,056,136	10,288,660	43.85	234,633
2006	15,015,470.63	4,039,162	4,004,607	11,010,864	44.85	245,504
2007	14,162,130.30	3,600,014	3,569,216	10,592,914	45.48	232,914
2008	12,007,625.26	2,855,413	2,830,985	9,176,640	46.48	197,432
2009	11,561,904.84	2,575,992	2,553,954	9,007,950	47.10	191,252
2010	12,010,232.40	2,492,123	2,470,803	9,539,429	47.74	199,820
2011	16,830,388.17	3,212,921	3,185,435	13,644,954	48.74	279,954
2012	22,409,535.68	3,930,633	3,897,006	18,512,529	49.38	374,899
2013	30,067,736.14	4,768,743	4,727,946	25,339,790	50.38	502,973

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
2014	33,416,025.78	4,771,808	4,730,985	28,685,041	51.02	562,231
2015	31,728,792.05	3,997,828	3,963,627	27,765,165	52.02	533,740
2016	44,370,272.81	4,871,856	4,830,177	39,540,095	52.67	750,714
2017	39,816,707.04	3,722,862	3,691,013	36,125,694	53.32	677,526
2018	51,472,452.51	3,963,379	3,929,472	47,542,980	53.98	880,752
2019	73,645,075.34	4,403,976	4,366,300	69,278,775	54.98	1,260,072
2020	61,227,156.06	2,632,768	2,610,245	58,616,911	55.64	1,053,503
2021	54,991,993.03	1,435,291	1,423,012	53,568,981	55.97	957,102
2022	152,849,907.65	1,345,079	1,333,572	151,516,336	56.00	2,705,649
	908,181,881.66	155,957,166	154,622,955	753,558,927		15,244,607
PNG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1973	361,477.68	233,074	251,464	110,014	23.80	4,622
1974	563,862.54	357,675	385,896	177,966	24.50	7,264
1975	1,581,474.53	986,413	1,064,243	517,231	25.21	20,517
1976	1,080,707.31	662,614	714,896	365,811	25.92	14,113
1977	1,332,440.84	802,449	865,764	466,677	26.65	17,511
1978	1,740,749.89	1,029,114	1,110,314	630,436	27.39	23,017
1979	1,917,223.73	1,112,277	1,200,038	717,185	28.13	25,495
1980	2,061,259.53	1,172,465	1,264,975	796,284	28.89	27,563
1981	1,516,775.33	845,542	912,257	604,518	29.65	20,388
1982	1,543,555.81	925,207	998,208	545,348	27.07	20,146
1983	800,805.79	468,151	505,089	295,716	28.07	10,535
1984	1,020,829.10	585,548	631,749	389,080	28.62	13,595
1985	1,286,960.30	723,915	781,034	505,927	29.17	17,344
1986	1,981,051.35	1,084,626	1,170,206	810,846	30.17	26,876
1987	3,224,484.51	1,728,324	1,864,693	1,359,791	30.73	44,250
1988	5,790,700.60	3,036,643	3,276,242	2,514,459	31.29	80,360
1989	4,312,386.07	2,210,529	2,384,945	1,927,441	31.86	60,497
1990	4,770,833.57	2,372,058	2,559,219	2,211,614	32.86	67,304
1991	2,244,969.24	1,089,035	1,174,963	1,070,007	33.44	31,998
1992	2,720,177.31	1,286,100	1,387,577	1,332,601	34.01	39,183
1993	2,645,706.27	1,209,617	1,305,059	1,340,647	35.02	38,282
1994	5,361,090.86	2,383,541	2,571,608	2,789,482	35.60	78,356
1995	5,644,905.27	2,437,470	2,629,793	3,015,113	36.19	83,313
1996	6,568,132.30	2,732,343	2,947,932	3,620,201	37.20	97,317
1997	9,987,663.09	4,024,029	4,341,535	5,646,128	37.79	149,408

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1998	7,471,788.27	2,892,329	3,120,541	4,351,247	38.79	112,174
1999	5,229,881.16	1,953,884	2,108,050	3,121,831	39.40	79,234
2000	4,066,911.50	1,464,088	1,579,608	2,487,303	40.00	62,183
2001	7,159,177.68	2,462,757	2,657,075	4,502,103	41.00	109,807
2002	3,217,350.62	1,061,726	1,145,499	2,071,852	41.61	49,792
2003	4,333,361.98	1,368,909	1,476,919	2,856,443	42.23	67,640
2004	8,735,817.44	2,618,124	2,824,701	5,911,117	43.23	136,736
2005	6,593,121.90	1,880,358	2,028,723	4,564,399	43.85	104,091
2006	3,978,054.85	1,070,097	1,154,530	2,823,524	44.85	62,955
2007	5,603,623.84	1,424,441	1,536,833	4,066,791	45.48	89,419
2008	4,650,281.87	1,105,837	1,193,090	3,457,192	46.48	74,380
2009	5,594,837.58	1,246,530	1,344,884	4,249,953	47.10	90,233
2010	4,094,359.80	849,580	916,614	3,177,746	47.74	66,564
2011	5,586,262.94	1,066,418	1,150,561	4,435,702	48.74	91,007
2012	8,985,299.52	1,576,022	1,700,374	7,284,925	49.38	147,528
2013	5,729,559.92	908,708	980,407	4,749,153	50.38	94,267
2014	8,098,899.63	1,156,523	1,247,776	6,851,124	51.02	134,283
2015	15,595,812.91	1,965,072	2,120,121	13,475,692	52.02	259,048
2016	18,072,576.90	1,984,369	2,140,941	15,931,636	52.67	302,480
2017	21,047,313.72	1,967,924	2,123,198	18,924,116	53.32	354,916
2018	22,673,592.04	1,745,867	1,883,620	20,789,972	53.98	385,142
2019	27,288,395.57	1,631,846	1,760,603	25,527,793	54.98	464,311
2020	17,352,719.70	746,167	805,041	16,547,678	55.64	297,406
2021	18,723,432.87	488,682	527,240	18,196,193	55.97	325,106
2022	38,729,223.29	340,817	367,708	38,361,515	56.00	685,027
	350,671,880.32	72,475,834	78,194,360	272,477,520		5,664,983
CPG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1951	700.33	580	642	59	11.55	5
1967	7,582.05	5,337	5,904	1,678	19.84	85
1968	14,097.34	9,790	10,830	3,267	20.47	160
1969	11,677.33	7,998	8,848	2,829	21.11	134
1970	25,609.65	17,288	19,125	6,484	21.77	298
1971	363,246.74	241,585	267,260	95,986	22.44	4,277
1972	567,306.88	371,626	411,122	156,185	23.11	6,758
1973	453,757.41	292,574	323,668	130,089	23.80	5,466
1974	640,158.51	406,072	449,229	190,930	24.50	7,793

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

CPG
SURVIVOR CURVE.. IOWA 67-R3
NET SALVAGE PERCENT.. 0

1975	592,379.51	369,485	408,753	183,626	25.21	7,284
1976	363,241.57	222,714	246,384	116,858	25.92	4,508
1977	653,924.92	393,820	435,675	218,250	26.65	8,189
1978	544,169.06	321,707	355,898	188,272	27.39	6,874
1979	496,911.12	288,283	318,921	177,990	28.13	6,327
1980	739,462.82	420,614	465,316	274,147	28.89	9,489
1981	847,969.37	472,709	522,948	325,022	29.65	10,962
1982	763,586.41	457,694	506,337	257,249	27.07	9,503
1983	887,294.15	518,712	573,840	313,454	28.07	11,167
1984	1,414,722.15	811,485	897,728	516,994	28.62	18,064
1985	1,608,000.53	904,500	1,000,629	607,372	29.17	20,822
1986	1,900,374.47	1,040,455	1,151,033	749,341	30.17	24,837
1987	1,491,764.77	799,586	884,565	607,200	30.73	19,759
1988	2,128,618.73	1,116,248	1,234,881	893,738	31.29	28,563
1989	2,208,281.58	1,131,965	1,252,269	956,013	31.86	30,007
1990	2,318,543.79	1,152,780	1,275,296	1,043,248	32.86	31,748
1991	2,739,395.10	1,328,881	1,470,113	1,269,283	33.44	37,957
1992	2,188,648.38	1,034,793	1,144,769	1,043,879	34.01	30,693
1993	3,427,948.25	1,567,258	1,733,824	1,694,124	35.02	48,376
1994	3,499,369.78	1,555,820	1,721,170	1,778,199	35.60	49,949
1995	3,840,986.00	1,658,538	1,834,805	2,006,181	36.19	55,435
1996	4,774,825.21	1,986,327	2,197,431	2,577,394	37.20	69,285
1997	4,901,865.25	1,974,962	2,184,858	2,717,007	37.79	71,898
1998	5,712,225.04	2,211,202	2,446,205	3,266,020	38.79	84,197
1999	3,407,107.19	1,272,895	1,408,176	1,998,931	39.40	50,734
2000	4,961,363.34	1,786,091	1,975,914	2,985,449	40.00	74,636
2001	2,519,391.19	866,671	958,780	1,560,612	41.00	38,064
2002	4,186,622.42	1,381,585	1,528,418	2,658,205	41.61	63,884
2003	4,407,122.60	1,392,210	1,540,172	2,866,951	42.23	67,889
2004	4,625,951.48	1,386,398	1,533,742	3,092,209	43.23	71,529
2005	4,745,603.46	1,353,446	1,497,288	3,248,315	43.85	74,078
2006	6,358,070.08	1,710,321	1,892,091	4,465,979	44.85	99,576
2007	5,421,474.34	1,378,139	1,524,606	3,896,869	45.48	85,683
2008	4,924,113.54	1,170,954	1,295,401	3,628,712	46.48	78,070
2009	4,348,271.33	968,795	1,071,757	3,276,514	47.10	69,565
2010	6,229,343.69	1,292,589	1,429,963	4,799,380	47.74	100,532
2011	7,178,085.64	1,370,297	1,515,930	5,662,155	48.74	116,171
2012	5,190,501.72	910,414	1,007,171	4,183,330	49.38	84,717
2013	5,557,948.25	881,491	975,175	4,582,774	50.38	90,964
2014	7,534,533.85	1,075,931	1,190,279	6,344,254	51.02	124,348
2015	14,031,151.57	1,767,925	1,955,818	12,075,334	52.02	232,129
2016	12,524,269.87	1,375,165	1,521,316	11,002,954	52.67	208,904

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
2017	13,234,045.48	1,237,383	1,368,890	11,865,155	53.32	222,527
2018	16,666,657.69	1,283,333	1,419,724	15,246,934	53.98	282,455
2019	7,895,698.71	472,163	522,344	7,373,355	54.98	134,110
2020	4,708,757.56	202,477	223,996	4,484,762	55.64	80,603
2021	11,548,800.73	301,424	333,459	11,215,342	55.97	200,381
2022	29,748,890.58	261,790	289,613	29,459,278	56.00	526,059
	244,082,420.51	52,193,275	57,740,301	186,342,120		3,898,477
	1,502,936,182.49	280,626,275	290,557,616	1,212,378,567		24,808,067

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.9 1.65

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1879	659.47	659	659			
1880	174.07	174	174			
1881	398.46	398	398			
1882	65.48	65	65			
1885	1.97	2	2			
1887	47.25	46	45	2	1.72	1
1888	200.21	194	190	10	2.05	5
1889	26.46	26	26			
1890	168.88	162	159	10	2.72	4
1891	6.71	6	6	1	3.07	
1893	203.32	192	188	15	3.73	4
1894	1.05	1	1			
1895	58.16	55	54	4	4.36	1
1896	182.14	170	167	15	4.66	3
1897	64.00	59	58	6	4.96	1
1898	217.03	201	197	20	5.26	4
1899	1,059.11	975	957	102	5.56	18
1901	1,688.66	1,540	1,512	177	6.15	29
1902	796.91	723	710	87	6.45	13
1903	2,592.08	2,342	2,299	293	6.74	43
1904	6,405.05	5,762	5,656	749	7.03	107
1905	2,647.75	2,371	2,327	320	7.31	44
1906	4,348.23	3,877	3,806	542	7.58	72
1907	2,832.23	2,515	2,469	363	7.85	46
1908	6,096.37	5,390	5,291	805	8.11	99
1909	6,199.36	5,458	5,358	842	8.37	101
1910	8,516.29	7,467	7,330	1,186	8.62	138
1911	18,353.37	16,029	15,735	2,619	8.86	296
1912	11,855.25	10,313	10,124	1,732	9.10	190
1913	18,972.95	16,442	16,140	2,833	9.33	304
1914	49,882.86	43,055	42,264	7,619	9.57	796
1915	23,110.42	19,874	19,509	3,601	9.79	368
1916	18,757.18	16,070	15,775	2,982	10.01	298
1917	3,711.15	3,168	3,110	601	10.22	59
1918	3,925.13	3,339	3,278	647	10.43	62
1919	5,058.20	4,287	4,208	850	10.64	80
1920	2,229.75	1,883	1,848	381	10.84	35
1921	8,995.14	7,572	7,433	1,562	11.03	142

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1922	13,696.94	11,491	11,280	2,417	11.22	215
1923	14,286.12	11,944	11,725	2,561	11.41	224
1924	41,701.83	34,753	34,115	7,587	11.59	655
	280,192.99	241,050	236,649	43,544		4,457
PNG						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1904	1,105.76	995	834	272	7.03	39
1906	474.40	423	355	120	7.58	16
1911	694.84	607	509	186	8.86	21
1912	2,740.98	2,384	1,998	743	9.10	82
1914	323.12	279	234	89	9.57	9
1915	4,151.12	3,570	2,992	1,159	9.79	118
1916	115.80	99	83	33	10.01	3
1923	142.48	119	100	43	11.41	4
1924	16.64	14	12	5	11.59	
1928	50.38	41	34	16	12.27	1
1939	122.80	98	82	41	13.83	3
1940	29.32	23	19	10	13.95	1
1943	24.50	19	16	9	14.30	1
	9,992.14	8,671	7,268	2,724		298
	290,185.13	249,721	243,917	46,268		4,755

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.7 1.64

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.7 REG AFUDC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	1,322,088.00	396,626	398,720	923,368	3.50	263,819
	1,322,088.00	396,626	398,720	923,368		263,819

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.5   19.95

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1971	57,501.80	37,070	35,600	21,902	16.70	1,311
1972	26,722.83	16,978	16,305	10,418	17.14	608
1973	7,231.90	4,527	4,347	2,884	17.58	164
1974	42,244.97	26,048	25,015	17,230	18.02	956
1975	33,101.31	20,100	19,303	13,799	18.46	748
1976	54,258.87	32,428	31,142	23,117	18.91	1,222
1977	23,327.13	13,718	13,174	10,153	19.36	524
1978	29,092.93	16,831	16,163	12,930	19.81	653
1979	27,807.93	15,815	15,188	12,620	20.27	623
1980	89,221.77	49,870	47,892	41,330	20.73	1,994
1981	156,404.27	85,857	82,452	73,953	21.20	3,488
1982	150,886.55	103,267	99,171	51,715	18.67	2,770
1983	32,250.68	21,782	20,918	11,333	18.98	597
1984	74,196.67	49,415	47,455	26,742	19.31	1,385
1985	165,115.81	108,349	104,052	61,064	19.65	3,108
1986	180,678.88	116,719	112,090	68,589	20.00	3,429
1987	135,733.31	86,245	82,824	52,909	20.37	2,597
1988	143,982.27	89,903	86,337	57,645	20.75	2,778
1989	312,995.53	191,866	184,256	128,740	21.15	6,087
1990	128,519.94	77,690	74,609	53,911	21.26	2,536
1991	182,507.62	108,081	103,794	78,713	21.69	3,629
1992	267,601.74	155,905	149,721	117,880	21.85	5,395
1993	82,155.80	46,780	44,925	37,231	22.31	1,669
1994	172,563.32	96,394	92,571	79,993	22.52	3,552
1995	378,939.88	206,333	198,149	180,791	23.01	7,857
1996	871,947.19	464,399	445,979	425,968	23.25	18,321
1997	282,713.43	147,068	141,235	141,479	23.52	6,015
1998	484,554.34	245,766	236,018	248,536	23.81	10,438
1999	141,263.40	69,713	66,948	74,315	24.12	3,081
2000	624,421.06	299,223	287,355	337,066	24.45	13,786
2001	409,129.27	190,900	183,328	225,801	24.58	9,186
2002	252,684.52	113,961	109,441	143,244	24.95	5,741
2003	2,138,845.02	934,248	897,192	1,241,653	25.14	49,390
2004	1,172,940.79	492,635	473,095	699,845	25.55	27,391
2005	868,118.86	350,894	336,976	531,143	25.79	20,595
2006	845,457.48	327,868	314,864	530,594	26.05	20,368
2007	721,471.80	267,233	256,634	464,838	26.34	17,648
2008	1,453,682.81	512,278	491,959	961,724	26.65	36,087
2009	534,320.41	178,890	171,795	362,526	26.82	13,517
2010	571,647.87	180,755	173,586	398,062	27.03	14,727
2011	2,451,008.26	727,214	698,370	1,752,638	27.26	64,293
2012	2,391,035.01	660,404	634,210	1,756,825	27.52	63,838

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
2013	910,623.12	231,845	222,649	687,974	27.81	24,738
2014	1,491,883.76	347,460	333,679	1,158,205	28.00	41,364
2015	4,992,592.68	1,048,444	1,006,859	3,985,734	28.21	141,288
2016	3,625,803.48	676,575	649,740	2,976,064	28.34	105,013
2017	3,129,390.85	506,023	485,952	2,643,438	28.51	92,720
2018	1,735,568.44	235,864	226,509	1,509,060	28.61	52,746
2019	5,127,541.33	556,338	534,272	4,593,270	28.76	159,710
2020	2,498,124.04	199,850	191,923	2,306,201	28.75	80,216
2021	5,811,259.60	287,657	276,248	5,535,012	28.80	192,188
2022	24,472,772.62	420,932	404,236	24,068,536	28.57	842,441
	72,965,845.15	12,452,408	11,958,502	61,007,343		2,186,526
PNG						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1957	2,382.51	1,832	1,646	736	10.86	68
1958	18,492.98	14,059	12,633	5,860	11.27	520
1959	6,536.74	4,914	4,415	2,121	11.67	182
1960	20,145.04	14,967	13,449	6,696	12.08	554
1961	16,382.26	12,029	10,809	5,574	12.49	446
1962	20,207.60	14,661	13,174	7,034	12.90	545
1963	44,509.81	31,905	28,668	15,841	13.31	1,190
1964	46,802.32	33,130	29,769	17,033	13.73	1,241
1965	94,791.64	66,254	59,533	35,259	14.15	2,492
1966	78,679.88	54,289	48,782	29,898	14.57	2,052
1967	94,154.02	64,125	57,620	36,534	14.99	2,437
1968	137,395.10	92,347	82,979	54,416	15.41	3,531
1969	368,941.83	244,601	219,787	149,155	15.84	9,416
1970	316,667.40	207,047	186,043	130,625	16.27	8,029
1971	158,380.43	102,105	91,747	66,634	16.70	3,990
1972	55,833.85	35,472	31,873	23,960	17.14	1,398
1973	145,411.08	91,022	81,788	63,623	17.58	3,619
1974	55,117.75	33,986	30,538	24,580	18.02	1,364
1975	25,827.68	15,683	14,092	11,736	18.46	636
1976	46,409.84	27,737	24,923	21,487	18.91	1,136
1977	197,964.25	116,421	104,610	93,354	19.36	4,822
1978	7,636.14	4,418	3,970	3,666	19.81	185
1979	26,541.30	15,095	13,564	12,978	20.27	640
1980	106,614.34	59,591	53,546	53,069	20.73	2,560

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1981	429,200.14	235,605	211,704	217,496	21.20	10,259
1982	311,081.07	212,904	191,306	119,775	18.67	6,415
1983	212,863.04	143,768	129,183	83,680	18.98	4,409
1984	53,355.65	35,535	31,930	21,426	19.31	1,110
1985	99,397.85	65,225	58,608	40,790	19.65	2,076
1986	127,145.66	82,136	73,804	53,342	20.00	2,667
1987	250,624.08	159,247	143,092	107,532	20.37	5,279
1988	114,930.53	71,763	64,483	50,448	20.75	2,431
1989	192,557.55	118,038	106,063	86,494	21.15	4,090
1990	102,306.31	61,844	55,570	46,736	21.26	2,198
1991	76,874.65	45,525	40,907	35,968	21.69	1,658
1992	142,546.90	83,048	74,623	67,924	21.85	3,109
1993	173,244.66	98,646	88,639	84,606	22.31	3,792
1994	411,916.04	230,096	206,754	205,162	22.52	9,110
1995	286,109.64	155,787	139,983	146,127	23.01	6,351
1996	192,604.16	102,581	92,175	100,430	23.25	4,320
1997	413,871.29	215,296	193,455	220,416	23.52	9,371
1998	436,252.21	221,267	198,820	237,432	23.81	9,972
1999	139,671.69	68,928	61,935	77,736	24.12	3,223
2000	127,659.82	61,175	54,969	72,691	24.45	2,973
2001	698,301.75	325,828	292,774	405,528	24.58	16,498
2002	106,917.07	48,220	43,328	63,589	24.95	2,549
2003	115,486.75	50,445	45,328	70,159	25.14	2,791
2004	483,735.08	203,169	182,558	301,177	25.55	11,788
2005	283,183.91	114,463	102,851	180,333	25.79	6,992
2006	246,781.06	95,702	85,993	160,788	26.05	6,172
2007	876,931.66	324,815	291,864	585,068	26.34	22,212
2008	782,915.19	275,899	247,910	535,005	26.65	20,075
2009	102,569.37	34,340	30,856	71,713	26.82	2,674
2010	89,819.81	28,401	25,520	64,300	27.03	2,379
2011	1,481,275.33	439,494	394,909	1,086,366	27.26	39,852
2012	447,154.23	123,504	110,975	336,179	27.52	12,216
2013	22,258.68	5,667	5,092	17,167	27.81	617
2014	3,075,540.90	716,293	643,628	2,431,913	28.00	86,854
2015	1,477,176.99	310,207	278,738	1,198,439	28.21	42,483
2016	1,185,439.14	221,203	198,763	986,676	28.34	34,816
2017	1,871,984.54	302,700	271,992	1,599,992	28.51	56,120
2018	10,815,255.58	1,469,793	1,320,688	9,494,568	28.61	331,862
2019	7,219,333.78	783,298	703,835	6,515,499	28.76	226,547

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

PNG
SURVIVOR CURVE.. IOWA 47-S0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2020	4,545,787.96	363,663	326,771	4,219,017	28.75	146,748
2021	2,157,959.21	106,819	95,983	2,061,977	28.80	71,596
2022	11,881,016.53	204,353	183,622	11,697,394	28.57	409,429
	56,352,863.25	10,374,380	9,321,935	47,030,928		1,701,136

CPG
SURVIVOR CURVE.. IOWA 47-S0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1965	747.40	522	551	197	14.15	14
1966	10,409.60	7,183	7,578	2,832	14.57	194
1967	9,424.55	6,419	6,772	2,653	14.99	177
1968	5,308.91	3,568	3,764	1,545	15.41	100
1969	8,638.93	5,727	6,042	2,597	15.84	164
1970	9,240.20	6,042	6,374	2,866	16.27	176
1971	6,819.67	4,397	4,639	2,181	16.70	131
1972	16,174.23	10,276	10,841	5,333	17.14	311
1973	14,391.69	9,009	9,504	4,888	17.58	278
1974	14,277.61	8,804	9,288	4,990	18.02	277
1975	36,488.80	22,157	23,375	13,114	18.46	710
1976	7,017.75	4,194	4,424	2,593	18.91	137
1977	22,048.31	12,966	13,679	8,370	19.36	432
1978	8,918.59	5,159	5,443	3,476	19.81	175
1979	36,291.99	20,640	21,774	14,518	20.27	716
1980	26,401.27	14,757	15,568	10,833	20.73	523
1981	34,819.11	19,114	20,164	14,655	21.20	691
1982	95,501.25	65,361	68,953	26,548	18.67	1,422
1983	80,085.99	54,090	57,063	23,023	18.98	1,213
1984	56,327.79	37,514	39,576	16,752	19.31	868
1985	47,041.67	30,869	32,565	14,476	19.65	737
1986	89,495.41	57,814	60,991	28,504	20.00	1,425
1987	80,266.29	51,001	53,804	26,462	20.37	1,299
1988	76,276.48	47,627	50,244	26,032	20.75	1,255
1989	69,028.73	42,315	44,640	24,388	21.15	1,153
1990	102,613.72	62,030	65,439	37,175	21.26	1,749
1991	72,357.25	42,850	45,205	27,152	21.69	1,252
1992	122,482.07	71,358	75,280	47,202	21.85	2,160
1993	133,583.41	76,062	80,242	53,341	22.31	2,391
1994	97,820.75	54,643	57,646	40,175	22.52	1,784
1995	125,055.41	68,093	71,835	53,220	23.01	2,313

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1996	224,716.41	119,684	126,261	98,455	23.25	4,235
1997	169,227.92	88,032	92,870	76,358	23.52	3,247
1998	169,525.34	85,983	90,708	78,817	23.81	3,310
1999	261,337.04	128,970	136,058	125,279	24.12	5,194
2000	168,187.04	80,595	85,024	83,163	24.45	3,401
2001	447,833.66	208,959	220,443	227,391	24.58	9,251
2002	241,766.80	109,037	115,029	126,738	24.95	5,080
2003	290,892.96	127,062	134,045	156,848	25.14	6,239
2004	330,890.10	138,974	146,611	184,279	25.55	7,212
2005	218,842.45	88,456	93,317	125,525	25.79	4,867
2006	404,851.19	157,001	165,629	239,222	26.05	9,183
2007	345,506.90	127,976	135,009	210,498	26.34	7,992
2008	454,845.41	160,288	169,097	285,749	26.65	10,722
2009	205,715.55	68,874	72,659	133,056	26.82	4,961
2010	263,128.42	83,201	87,773	175,355	27.03	6,487
2011	620,366.38	184,063	194,178	426,188	27.26	15,634
2012	430,585.74	118,928	125,464	305,122	27.52	11,087
2013	868,838.71	221,206	233,363	635,476	27.81	22,851
2014	394,217.13	91,813	96,859	297,358	28.00	10,620
2015	3,926,804.97	824,629	869,948	3,056,857	28.21	108,361
2016	980,488.09	182,959	193,014	787,474	28.34	27,787
2017	515,277.70	83,320	87,899	427,379	28.51	14,990
2018	476,990.57	64,823	68,385	408,605	28.61	14,282
2019	211,591.51	22,958	24,220	187,372	28.76	6,515
2020	1,657,101.14	132,568	139,853	1,517,248	28.75	52,774
2021	6,772,228.59	335,225	353,648	6,418,581	28.80	222,867
2022	5,938,975.88	102,150	107,764	5,831,212	28.57	204,103
	28,506,088.43	5,060,295	5,338,390	23,167,698		829,479
	157,824,796.83	27,887,083	26,618,827	131,205,969		4,717,141

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.8   2.99

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1954	1,330.58	1,208	1,331			
1956	21,290.16	19,057	21,290			
1957	5,372.45	4,774	5,372			
1958	8,518.07	7,515	8,518			
1959	4,392.86	3,846	4,393			
1960	27,087.71	23,536	27,088			
1961	1,916.00	1,652	1,916			
1962	1,339.47	1,146	1,339			
1963	30.71	26	31			
1965	41,595.76	34,691	41,596			
1966	19,579.16	16,181	19,579			
1967	14,375.52	11,772	14,376			
1968	818.29	664	818			
1969	15,932.36	12,792	15,932			
1970	553.00	439	553			
1972	36,690.90	28,513	36,691			
1973	38,195.02	29,334	38,195			
1974	19,018.54	14,429	19,019			
1975	25,329.73	18,969	25,330			
1976	12,818.60	9,472	12,730	89	11.75	8
1977	148.01	108	145	3	12.21	
1978	4,242.67	3,046	4,094	149	12.69	12
1979	1,542.38	1,091	1,466	76	13.18	6
1980	4,638.03	3,228	4,338	300	13.68	22
1981	80,176.22	54,894	73,775	6,402	14.19	451
1982	141,945.62	106,928	141,946			
1983	6,800.47	5,050	6,791	10	13.69	1
1984	199,926.07	146,246	196,654	3,272	14.13	232
1985	433,461.53	312,092	419,665	13,797	14.58	946
1986	265,735.11	188,167	253,025	12,710	15.05	845
1987	791,585.85	550,785	740,631	50,955	15.52	3,283
1988	18,764.80	12,818	17,236	1,529	16.01	96
1989	37,807.02	25,331	34,062	3,745	16.50	227
1990	128,484.87	84,350	113,424	15,061	17.00	886
1991	257,739.07	165,623	222,710	35,029	17.52	1,999
1992	198,243.74	124,557	167,490	30,754	18.04	1,705
1993	32,985.36	20,240	27,216	5,769	18.58	310
1994	6,197.62	3,709	4,987	1,210	19.12	63
1995	265,285.40	154,661	207,970	57,315	19.67	2,914
1996	390,043.61	221,194	297,436	92,608	20.23	4,578
1998	8,401.63	4,487	6,034	2,368	21.37	111
2003	278,252.13	124,267	167,100	111,152	24.17	4,599

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2008	144,233.30	50,395	67,765	76,468	27.00	2,832
2009	23,277.53	7,668	10,311	12,967	27.48	472
2013	87,005.59	21,160	28,453	58,552	29.56	1,981
2014	78,923.32	17,442	23,454	55,469	29.96	1,851
2017	32,073.62	4,798	6,452	25,622	31.26	820
2019	90,422.23	8,952	12,038	78,385	31.84	2,462
2021	3,108,012.93	141,725	190,575	2,917,438	31.39	92,942
	7,412,540.62	2,805,028	3,743,339	3,669,202		126,654
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1960	16,780.37	14,580	12,806	3,974	5.90	674
1962	29,310.05	25,070	22,020	7,290	6.51	1,120
1963	28,716.91	24,365	21,401	7,316	6.82	1,073
1964	1,610.71	1,355	1,190	421	7.14	59
1965	15,335.53	12,790	11,234	4,101	7.47	549
1966	114,389.19	94,536	83,036	31,354	7.81	4,015
1967	4,284.76	3,509	3,082	1,203	8.15	148
1968	126,189.95	102,354	89,903	36,287	8.50	4,269
1969	116,466.84	93,510	82,134	34,332	8.87	3,871
1970	18,752.91	14,902	13,089	5,664	9.24	613
1971	13,464.24	10,583	9,296	4,169	9.63	433
1972	2,349.36	1,826	1,604	745	10.03	74
1974	21,308.55	16,166	14,199	7,109	10.86	655
1975	37,036.13	27,736	24,362	12,674	11.30	1,122
1977	2,043.72	1,489	1,308	736	12.21	60
1978	2,934.41	2,107	1,851	1,084	12.69	85
1979	1,353.24	957	841	513	13.18	39
1980	47,010.45	32,719	28,739	18,272	13.68	1,336
1981	702,199.80	480,775	422,289	279,911	14.19	19,726
1982	114,036.20	85,903	75,453	38,583	13.26	2,910
1983	6,538.51	4,855	4,264	2,274	13.69	166
1984	1,848.56	1,352	1,188	661	14.13	47
1985	33,053.50	23,799	20,904	12,150	14.58	833
1986	796.80	564	495	301	15.05	20
1987	900.93	627	551	350	15.52	23
1988	228,712.92	156,234	137,228	91,485	16.01	5,714
1989	5,767.35	3,864	3,394	2,373	16.50	144

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1990	8,208.45	5,389	4,733	3,475	17.00	204
1991	15,153.04	9,737	8,552	6,601	17.52	377
1992	1,292.66	812	713	579	18.04	32
1993	49,169.36	30,170	26,500	22,670	18.58	1,220
1994	82,378.57	49,304	43,306	39,072	19.12	2,044
1995	52,734.74	30,744	27,004	25,731	19.67	1,308
1996	44,580.63	25,282	22,206	22,374	20.23	1,106
1997	532,333.33	293,209	257,540	274,793	20.80	13,211
1998	118,063.23	63,058	55,387	62,676	21.37	2,933
1999	58,548.09	30,269	26,587	31,961	21.95	1,456
2000	69,703.96	34,817	30,582	39,122	22.55	1,735
2001	173,986.69	84,175	73,935	100,052	22.94	4,361
2002	184,888.86	86,047	75,579	109,309	23.55	4,642
2003	175,733.00	78,482	68,935	106,798	24.17	4,419
2004	75,956.41	32,600	28,634	47,322	24.60	1,924
2005	48,587.58	19,897	17,477	31,111	25.24	1,233
2006	162,733.73	63,369	55,660	107,074	25.87	4,139
2007	9,461.70	3,505	3,079	6,383	26.34	242
2008	460,995.77	161,072	141,478	319,518	27.00	11,834
2009	53,996.90	17,787	15,623	38,374	27.48	1,396
2010	265,809.52	82,082	72,097	193,713	27.98	6,923
2011	1,348,202.00	387,608	340,455	1,007,747	28.50	35,360
2012	500,205.13	132,854	116,692	383,513	29.03	13,211
2013	309,369.28	75,239	66,086	243,283	29.56	8,230
2014	8,711,938.63	1,925,338	1,691,120	7,020,818	29.96	234,340
2015	784,772.22	154,757	135,931	648,841	30.52	21,260
2018	1.37			1	31.60	
2020	1,817,684.99	132,691	116,549	1,701,136	31.75	53,579
2021	185,706.35	8,468	7,438	178,268	31.39	5,679
	17,995,388.08	5,257,289	4,617,739	13,377,649		488,176
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1955	266.15	240	220	46	4.43	10
1957	1,419.60	1,262	1,155	264	5.01	53
1959	1,154.96	1,011	926	229	5.60	41
1960	352.50	306	280	72	5.90	12
1961	3,229.10	2,784	2,549	680	6.20	110

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1966	2,958.56	2,445	2,238	720	7.81	92
1967	3,788.99	3,103	2,841	948	8.15	116
1968	2,785.64	2,259	2,068	718	8.50	84
1970	2,147.66	1,707	1,563	585	9.24	63
1972	481.68	374	342	139	10.03	14
1973	1,415.71	1,087	995	421	10.44	40
1974	1,983.52	1,505	1,378	606	10.86	56
1975	1,411.62	1,057	968	444	11.30	39
1977	3,626.30	2,642	2,419	1,208	12.21	99
1979	10,681.17	7,553	6,915	3,767	13.18	286
1981	703.40	482	441	262	14.19	18
1982	2,492.78	1,878	1,719	774	13.26	58
1988	1,548.80	1,058	969	580	16.01	36
1989	1,790.48	1,200	1,099	692	16.50	42
1992	417.27	262	240	177	18.04	10
1995	551.52	322	295	257	19.67	13
2012	1,055.35	280	256	799	29.03	28
2013	422.81	103	94	329	29.56	11
2019	181,294.79	17,948	16,431	164,864	31.84	5,178
	227,980.36	52,868	48,399	179,581		6,509
	25,635,909.06	8,115,185	8,409,477	17,226,432		621,339

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.7   2.42

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1922	1,014.66	1,015	1,015			
1923	1,951.90	1,952	1,952			
1924	1,808.76	1,809	1,809			
1925	2,427.69	2,428	2,428			
1926	2,500.88	2,501	2,501			
1927	4,426.27	4,426	4,426			
1928	3,224.12	3,224	3,224			
1929	5,642.79	5,643	5,643			
1930	5,019.17	5,019	5,019			
1931	3,092.04	3,080	2,996	96	0.18	96
1932	902.02	894	870	32	0.41	32
1933	2,173.12	2,142	2,084	90	0.66	90
1934	1,683.75	1,650	1,605	79	0.93	79
1935	1,914.75	1,865	1,814	101	1.20	84
1936	3,081.42	2,983	2,902	180	1.47	122
1937	2,918.66	2,808	2,731	187	1.74	107
1938	2,705.92	2,588	2,517	188	2.01	94
1939	2,527.16	2,402	2,336	191	2.28	84
1940	2,816.56	2,660	2,587	229	2.56	89
1941	4,879.43	4,578	4,453	426	2.84	150
1942	1,891.44	1,763	1,715	177	3.12	57
1943	1,186.44	1,098	1,068	118	3.41	35
1944	1,950.03	1,794	1,745	205	3.69	56
1945	1,365.93	1,248	1,214	152	3.98	38
1946	3,156.52	2,864	2,786	371	4.27	87
1947	10,956.80	9,871	9,602	1,355	4.56	297
1948	11,577.35	10,354	10,072	1,506	4.86	310
1949	16,526.53	14,673	14,273	2,254	5.16	437
1950	18,582.14	16,376	15,929	2,653	5.46	486
1951	14,142.13	12,371	12,034	2,108	5.76	366
1952	16,970.12	14,731	14,329	2,641	6.07	435
1953	13,997.58	12,056	11,727	2,270	6.38	356
1954	23,717.06	20,268	19,715	4,002	6.69	598
1955	41,684.47	35,332	34,368	7,316	7.01	1,044
1956	73,926.59	62,163	60,468	13,459	7.32	1,839
1957	94,564.68	78,839	76,689	17,876	7.65	2,337
1958	128,349.16	106,111	103,217	25,132	7.97	3,153
1959	220,770.77	180,937	176,003	44,768	8.30	5,394
1960	300,325.27	243,981	237,327	62,998	8.63	7,300
1961	322,858.58	259,901	252,813	70,045	8.97	7,809
1962	308,749.67	246,262	239,546	69,203	9.31	7,433
1963	355,915.75	281,252	273,582	82,334	9.65	8,532

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1964	349,846.37	273,793	266,326	83,520	10.00	8,352
1965	467,688.23	362,458	352,573	115,115	10.35	11,122
1966	571,888.69	438,736	426,771	145,117	10.71	13,550
1967	541,443.61	411,145	399,933	141,511	11.07	12,783
1968	619,192.00	465,199	452,513	166,679	11.44	14,570
1969	644,767.97	479,230	466,161	178,607	11.81	15,123
1970	656,926.47	482,841	469,674	187,253	12.19	15,361
1971	724,998.80	526,886	512,517	212,481	12.57	16,904
1972	983,116.97	706,134	686,877	296,240	12.96	22,858
1973	1,266,077.26	898,636	874,129	391,948	13.35	29,359
1974	1,312,217.20	919,982	894,893	417,324	13.75	30,351
1975	909,524.66	629,746	612,572	296,952	14.15	20,986
1976	1,023,415.39	699,484	680,408	343,007	14.56	23,558
1977	1,944,115.17	1,311,014	1,275,262	668,854	14.98	44,650
1978	1,760,664.16	1,171,229	1,139,289	621,376	15.40	40,349
1979	3,175,458.59	2,082,688	2,025,891	1,149,567	15.83	72,620
1980	5,184,836.08	3,350,960	3,259,576	1,925,260	16.27	118,332
1981	5,285,216.07	3,365,308	3,273,533	2,011,683	16.71	120,388
1982	4,719,342.96	3,440,401	3,346,578	1,372,765	15.06	91,153
1983	3,436,072.86	2,470,193	2,402,829	1,033,244	15.45	66,877
1984	3,603,249.95	2,552,542	2,482,932	1,120,318	15.85	70,683
1985	4,099,313.80	2,874,439	2,796,051	1,303,263	15.98	81,556
1986	4,346,159.31	2,997,981	2,916,224	1,429,936	16.41	87,138
1987	5,096,650.66	3,455,529	3,361,294	1,735,357	16.86	102,927
1988	6,472,259.12	4,309,230	4,191,714	2,280,545	17.32	131,671
1989	9,139,752.45	6,001,161	5,837,504	3,302,248	17.52	188,484
1990	10,138,303.41	6,523,998	6,346,083	3,792,220	18.01	210,562
1991	9,141,944.98	5,788,680	5,630,818	3,511,127	18.25	192,391
1992	9,206,204.80	5,700,482	5,545,025	3,661,180	18.76	195,159
1993	5,968,489.61	3,627,051	3,528,138	2,440,351	19.04	128,170
1994	12,102,100.23	7,174,125	6,978,481	5,123,620	19.58	261,676
1995	12,935,074.29	7,504,930	7,300,264	5,634,810	19.90	283,156
1996	10,871,439.18	6,135,840	5,968,510	4,902,929	20.45	239,752
1997	11,839,892.81	6,521,413	6,343,569	5,496,324	20.80	264,246
1998	9,542,456.47	5,120,482	4,980,842	4,561,614	21.16	215,577
1999	9,648,360.88	5,033,550	4,896,281	4,752,080	21.55	220,514
2000	10,070,513.74	5,075,539	4,937,125	5,133,389	22.14	231,860
2001	10,015,884.39	4,887,752	4,754,459	5,261,426	22.56	233,219
2002	10,487,785.01	4,944,991	4,810,137	5,677,648	22.98	247,069
2003	8,957,820.25	4,070,434	3,959,430	4,998,390	23.42	213,424
2004	11,301,967.65	4,934,439	4,799,873	6,502,095	23.87	272,396
2005	9,720,408.28	4,065,075	3,954,217	5,766,191	24.34	236,902

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

UGI-GAS
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2006	10,390,673.11	4,131,332	4,018,667	6,372,006	25.00	254,880
2007	10,286,508.75	3,890,358	3,784,265	6,502,244	25.48	255,190
2008	13,504,776.34	4,837,411	4,705,491	8,799,286	25.98	338,695
2009	13,844,390.94	4,672,482	4,545,059	9,299,331	26.50	350,918
2010	14,171,560.21	4,481,047	4,358,845	9,812,715	27.03	363,031
2011	21,716,209.58	6,393,252	6,218,903	15,497,307	27.56	562,312
2012	31,787,386.82	8,611,203	8,376,368	23,411,019	28.26	828,415
2013	41,319,155.36	10,247,151	9,967,703	31,351,453	28.81	1,088,214
2014	40,191,309.73	8,986,777	8,741,700	31,449,610	29.52	1,065,366
2015	41,857,033.22	8,350,478	8,122,753	33,734,280	30.09	1,121,113
2016	45,595,741.23	7,942,778	7,726,172	37,869,570	30.81	1,229,132
2017	43,194,893.53	6,414,442	6,239,515	36,955,379	31.54	1,171,699
2018	49,275,821.78	6,031,361	5,866,881	43,408,941	32.26	1,345,596
2019	66,700,182.19	6,396,547	6,222,108	60,478,074	33.00	1,832,669
2020	75,793,035.64	5,214,561	5,072,356	70,720,680	33.86	2,088,620
2021	85,984,602.28	3,559,763	3,462,685	82,521,917	34.73	2,376,099
2022	43,597,556.43	601,646	585,239	43,012,318	35.60	1,208,211
	881,533,554.00	236,218,227	229,777,119	651,756,435		22,627,364

PNG
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1917	1,894.51	1,895	1,895			
1918	575.19	575	575			
1919	2,455.99	2,456	2,456			
1920	3,065.73	3,066	3,066			
1921	2,889.05	2,889	2,889			
1922	8,067.60	8,068	8,068			
1923	9,786.18	9,786	9,786			
1924	17,252.89	17,253	17,253			
1925	20,729.36	20,729	20,729			
1926	15,608.93	15,609	15,609			
1927	13,637.75	13,638	13,638			
1928	12,406.81	12,407	12,407			
1929	11,777.08	11,777	11,777			
1930	11,837.24	11,837	11,837			
1931	11,713.25	11,667	11,713			
1932	9,587.48	9,502	9,587			
1933	5,992.70	5,907	5,993			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

PNG
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1934	7,861.70	7,703	7,862			
1935	6,031.10	5,874	6,031			
1936	8,452.53	8,182	8,453			
1937	9,115.61	8,771	9,116			
1938	7,108.76	6,798	7,109			
1939	11,371.24	10,808	11,371			
1940	10,229.79	9,661	10,230			
1941	9,259.47	8,688	9,259			
1942	5,602.92	5,223	5,589	14	3.12	4
1943	3,970.31	3,676	3,934	37	3.41	11
1944	6,399.41	5,886	6,298	101	3.69	27
1945	10,455.65	9,551	10,220	235	3.98	59
1946	17,621.81	15,986	17,106	516	4.27	121
1947	18,794.19	16,931	18,117	677	4.56	148
1948	22,750.83	20,347	21,773	978	4.86	201
1949	20,336.87	18,056	19,321	1,016	5.16	197
1950	28,899.60	25,469	27,253	1,646	5.46	301
1951	21,834.26	19,100	20,438	1,396	5.76	242
1952	442,440.17	384,056	410,965	31,475	6.07	5,185
1953	17,105.71	14,733	15,765	1,340	6.38	210
1954	24,390.02	20,843	22,303	2,087	6.69	312
1955	41,221.36	34,940	37,388	3,833	7.01	547
1956	47,741.24	40,144	42,957	4,785	7.32	654
1957	66,244.10	55,228	59,098	7,147	7.65	934
1958	97,193.84	80,354	85,984	11,210	7.97	1,407
1959	154,601.79	126,707	135,585	19,017	8.30	2,291
1960	135,480.68	110,063	117,775	17,706	8.63	2,052
1961	163,869.50	131,915	141,158	22,712	8.97	2,532
1962	296,484.72	236,479	253,048	43,437	9.31	4,666
1963	373,231.27	294,935	315,600	57,632	9.65	5,972
1964	507,259.14	396,986	424,801	82,458	10.00	8,246
1965	606,777.12	470,252	503,200	103,577	10.35	10,007
1966	673,523.40	516,707	552,910	120,613	10.71	11,262
1967	791,145.01	600,756	642,848	148,297	11.07	13,396
1968	1,015,696.99	763,093	816,559	199,138	11.44	17,407
1969	1,075,328.22	799,248	855,247	220,081	11.81	18,635
1970	1,241,650.95	912,613	976,555	265,096	12.19	21,747
1971	437,814.96	318,178	340,471	97,344	12.57	7,744
1972	995,903.17	715,317	765,436	230,468	12.96	17,783
1973	1,281,222.64	909,386	973,102	308,121	13.35	23,080
1974	1,317,687.28	923,817	988,544	329,143	13.75	23,938
1975	1,124,098.78	778,315	832,847	291,251	14.15	20,583

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1976	1,360,351.24	929,773	994,917	365,434	14.56	25,098
1977	1,732,313.60	1,168,186	1,250,035	482,279	14.98	32,195
1978	1,317,758.28	876,599	938,018	379,741	15.40	24,659
1979	1,848,157.05	1,212,151	1,297,080	551,077	15.83	34,812
1980	2,441,167.77	1,577,727	1,688,270	752,898	16.27	46,275
1981	2,138,083.59	1,361,403	1,456,789	681,294	16.71	40,772
1982	1,769,315.32	1,289,831	1,380,203	389,113	15.06	25,838
1983	1,277,122.89	918,124	982,452	294,671	15.45	19,073
1984	1,796,898.16	1,272,923	1,362,110	434,788	15.85	27,431
1985	2,119,343.30	1,486,084	1,590,206	529,137	15.98	33,112
1986	2,687,429.64	1,853,789	1,983,674	703,755	16.41	42,886
1987	3,635,607.77	2,464,942	2,637,648	997,960	16.86	59,191
1988	4,818,966.40	3,208,468	3,433,269	1,385,698	17.32	80,006
1989	4,547,736.24	2,986,044	3,195,260	1,352,476	17.52	77,196
1990	4,992,973.30	3,212,978	3,438,095	1,554,879	18.01	86,334
1991	3,638,570.58	2,303,943	2,465,368	1,173,202	18.25	64,285
1992	4,411,054.45	2,731,325	2,922,695	1,488,360	18.76	79,337
1993	4,690,143.07	2,850,200	3,049,899	1,640,245	19.04	86,147
1994	4,750,313.05	2,815,986	3,013,287	1,737,026	19.58	88,714
1995	5,372,377.51	3,117,053	3,335,449	2,036,929	19.90	102,358
1996	5,457,924.81	3,080,453	3,296,284	2,161,641	20.45	105,704
1997	6,324,666.55	3,483,626	3,727,705	2,596,961	20.80	124,854
1998	5,888,037.27	3,159,521	3,380,892	2,507,145	21.16	118,485
1999	4,246,846.30	2,215,580	2,370,814	1,876,032	21.55	87,055
2000	3,534,735.28	1,781,507	1,906,328	1,628,407	22.14	73,550
2001	6,174,627.47	3,013,218	3,224,338	2,950,289	22.56	130,775
2002	5,075,798.49	2,393,239	2,560,921	2,514,878	22.98	109,438
2003	5,752,273.04	2,613,833	2,796,971	2,955,302	23.42	126,187
2004	11,794,538.53	5,149,496	5,510,294	6,284,244	23.87	263,270
2005	7,646,848.65	3,197,912	3,421,973	4,224,876	24.34	173,577
2006	4,639,794.03	1,844,782	1,974,036	2,665,758	25.00	106,630
2007	6,195,518.20	2,343,145	2,507,317	3,688,201	25.48	144,749
2008	6,656,955.95	2,384,522	2,551,593	4,105,363	25.98	158,020
2009	6,825,899.21	2,303,741	2,465,152	4,360,747	26.50	164,556
2010	4,445,659.39	1,405,717	1,504,208	2,941,451	27.03	108,822
2011	7,643,514.67	2,250,251	2,407,914	5,235,600	27.56	189,971
2012	9,621,169.55	2,606,375	2,788,990	6,832,180	28.26	241,762
2013	9,508,645.24	2,358,144	2,523,367	6,985,278	28.81	242,460
2014	10,267,622.26	2,295,840	2,456,697	7,810,925	29.52	264,598
2015	14,824,251.17	2,957,438	3,164,650	11,659,601	30.09	387,491
2016	15,769,411.51	2,747,031	2,939,501	12,829,910	30.81	416,420
2017	17,414,476.98	2,586,050	2,767,241	14,647,236	31.54	464,402

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2018	19,769,414.18	2,419,776	2,589,317	17,180,097	32.26	532,551
2019	26,625,917.85	2,553,426	2,732,331	23,893,587	33.00	724,048
2020	25,419,602.38	1,748,869	1,871,403	23,548,199	33.86	695,458
2021	29,522,639.56	1,222,237	1,307,873	28,214,767	34.73	812,403
2022	21,455,503.73	296,086	316,831	21,138,673	35.60	593,783
	373,161,461.31	116,050,180	124,168,566	248,992,895		8,858,639
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1930	6.00	6	6			
1931	316.67	315	317			
1935	33.70	33	34			
1941	48.76	46	49			
1942	31.73	30	32			
1946	295.07	268	291	4	4.27	1
1947	117.96	106	115	3	4.56	1
1948	3.90	3	3	1	4.86	
1949	207.36	184	200	7	5.16	1
1951	61.73	54	59	3	5.76	1
1952	42.37	37	40	2	6.07	
1953	69.98	60	65	5	6.38	1
1954	425.64	364	395	30	6.69	4
1955	1,217.58	1,032	1,121	97	7.01	14
1956	870.14	732	795	75	7.32	10
1958	2,996.69	2,477	2,691	306	7.97	38
1959	1,118.50	917	996	122	8.30	15
1960	197.58	161	175	23	8.63	3
1961	20,091.86	16,174	17,570	2,522	8.97	281
1962	8,764.93	6,991	7,594	1,171	9.31	126
1963	16,393.42	12,954	14,072	2,322	9.65	241
1964	17,918.33	14,023	15,233	2,685	10.00	268
1965	15,686.59	12,157	13,206	2,481	10.35	240
1966	15,082.41	11,571	12,570	2,513	10.71	235
1967	27,348.77	20,767	22,559	4,790	11.07	433
1968	31,232.89	23,465	25,490	5,743	11.44	502
1969	27,361.41	20,337	22,092	5,269	11.81	446
1970	30,189.14	22,189	24,104	6,085	12.19	499
1971	56,830.06	41,301	44,865	11,965	12.57	952

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

CPG
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

1972	74,112.66	53,232	57,826	16,287	12.96	1,257
1973	44,973.56	31,921	34,676	10,298	13.35	771
1974	114,488.43	80,267	87,194	27,295	13.75	1,985
1975	153,089.35	105,998	115,145	37,944	14.15	2,682
1976	101,386.51	69,296	75,276	26,111	14.56	1,793
1977	52,775.15	35,589	38,660	14,115	14.98	942
1978	67,288.57	44,762	48,625	18,664	15.40	1,212
1979	59,883.47	39,276	42,665	17,218	15.83	1,088
1980	144,903.85	93,651	101,733	43,171	16.27	2,653
1981	350,149.71	222,954	242,194	107,956	16.71	6,461
1982	340,274.36	248,060	269,466	70,808	15.06	4,702
1983	301,848.49	216,999	235,725	66,124	15.45	4,280
1984	401,021.64	284,084	308,599	92,423	15.85	5,831
1985	515,486.23	361,459	392,651	122,835	15.98	7,687
1986	592,365.04	408,613	443,874	148,491	16.41	9,049
1987	753,502.32	510,875	554,961	198,541	16.86	11,776
1988	729,246.16	485,532	527,431	201,815	17.32	11,652
1989	1,270,085.09	833,938	905,903	364,182	17.52	20,787
1990	1,294,575.21	833,059	904,948	389,627	18.01	21,634
1991	1,133,726.35	717,876	779,825	353,901	18.25	19,392
1992	1,758,602.31	1,088,927	1,182,896	575,706	18.76	30,688
1993	1,268,395.22	770,804	837,320	431,075	19.04	22,640
1994	2,253,723.23	1,336,007	1,451,298	802,426	19.58	40,982
1995	2,532,806.96	1,469,535	1,596,348	936,459	19.90	47,058
1996	2,443,215.08	1,378,951	1,497,947	945,268	20.45	46,223
1997	2,530,435.88	1,393,764	1,514,039	1,016,397	20.80	48,865
1998	2,828,823.23	1,517,947	1,648,938	1,179,885	21.16	55,760
1999	2,549,109.43	1,329,870	1,444,631	1,104,478	21.55	51,252
2000	2,277,118.12	1,147,668	1,246,706	1,030,412	22.14	46,541
2001	2,309,864.70	1,127,214	1,224,487	1,085,378	22.56	48,111
2002	3,518,321.91	1,658,889	1,802,043	1,716,279	22.98	74,686
2003	1,700,095.77	772,524	839,189	860,907	23.42	36,759
2004	2,589,630.16	1,130,633	1,228,201	1,361,429	23.87	57,035
2005	2,718,910.29	1,137,048	1,235,169	1,483,741	24.34	60,959
2006	1,860,525.67	739,745	803,581	1,056,944	25.00	42,278
2007	1,408,345.54	532,636	578,600	829,746	25.48	32,565
2008	4,068,788.14	1,457,440	1,583,210	2,485,578	25.98	95,673
2009	2,036,434.32	687,297	746,607	1,289,827	26.50	48,673
2010	3,095,610.45	978,832	1,063,300	2,032,310	27.03	75,187
2011	3,369,189.23	991,889	1,077,484	2,291,705	27.56	83,153
2012	6,011,506.67	1,628,517	1,769,050	4,242,457	28.26	150,122
2013	5,451,162.58	1,351,888	1,468,549	3,982,614	28.81	138,237

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2014	7,076,000.49	1,582,194	1,718,729	5,357,271	29.52	181,479
2015	6,866,084.03	1,369,784	1,487,989	5,378,095	30.09	178,734
2016	6,578,047.89	1,145,896	1,244,781	5,333,267	30.81	173,102
2017	5,287,646.87	785,216	852,976	4,434,671	31.54	140,605
2018	5,565,609.77	681,231	740,018	4,825,592	32.26	149,584
2019	6,779,331.12	650,138	706,242	6,073,090	33.00	184,033
2020	9,910,327.35	681,831	740,670	9,169,658	33.86	270,811
2021	7,318,199.19	302,973	329,118	6,989,081	34.73	201,240
2022	6,961,904.40	96,074	104,365	6,857,540	35.60	192,628
	131,693,909.32	38,809,557	42,158,594	89,535,315		3,147,609
	1,386,388,924.63	391,077,964	396,104,279	990,284,645		34,633,612

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.6 2.50

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

UGI-GAS
SURVIVOR CURVE.. IOWA 35-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1948	115.60	116	116			
1949	1,707.68	1,708	1,708			
1950	2,079.46	2,079	2,079			
1951	2,917.72	2,918	2,918			
1952	4,574.74	4,575	4,575			
1953	3,842.25	3,842	3,842			
1954	1,489.56	1,490	1,490			
1955	2,791.81	2,792	2,792			
1956	3,121.46	3,121	3,121			
1957	2,648.49	2,648	2,648			
1958	3,877.02	3,860	3,777	100	0.15	100
1959	7,681.92	7,598	7,435	247	0.38	247
1960	4,768.37	4,681	4,581	188	0.64	188
1961	6,172.79	6,014	5,885	288	0.90	288
1962	7,509.20	7,258	7,103	407	1.17	348
1963	7,815.64	7,492	7,332	484	1.45	334
1964	9,413.15	8,951	8,759	654	1.72	380
1965	9,773.96	9,215	9,018	756	2.00	378
1966	25,149.76	23,504	23,001	2,149	2.29	938
1967	52,098.85	48,273	47,240	4,859	2.57	1,891
1968	85,042.67	78,094	76,422	8,621	2.86	3,014
1969	82,428.77	75,010	73,404	9,025	3.15	2,865
1970	71,979.81	64,905	63,515	8,464	3.44	2,460
1971	46,692.21	41,703	40,810	5,882	3.74	1,573
1972	47,595.43	42,115	41,213	6,382	4.03	1,584
1973	77,312.10	67,769	66,318	10,994	4.32	2,545
1974	81,608.83	70,836	69,319	12,289	4.62	2,660
1975	62,343.21	53,562	52,415	9,928	4.93	2,014
1976	35,691.78	30,348	29,698	5,993	5.24	1,144
1977	43,310.77	36,430	35,650	7,661	5.56	1,378
1978	116,758.57	97,143	95,063	21,695	5.88	3,690
1979	131,399.46	108,048	105,735	25,665	6.22	4,126
1980	621,637.83	504,950	494,140	127,498	6.57	19,406
1981	353,699.73	283,565	277,494	76,206	6.94	10,981
1982	221,869.19	189,609	185,550	36,320	6.89	5,271
1983	27,047.23	22,863	22,374	4,674	7.23	646
1984	103,539.51	86,497	84,645	18,894	7.59	2,489
1985	337,434.72	279,666	273,679	63,756	7.75	8,227
1986	241,672.02	197,591	193,361	48,311	8.14	5,935
1987	393,645.11	317,199	310,408	83,237	8.56	9,724
1988	338,129.58	268,306	262,562	75,568	8.98	8,415
1989	529,839.49	413,593	404,738	125,101	9.42	13,280

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1990	891,314.90	683,639	669,003	222,312	9.87	22,524
1991	880,503.93	662,843	648,652	231,852	10.34	22,423
1992	815,275.17	601,755	588,872	226,403	10.82	20,924
1993	658,026.47	477,530	467,307	190,720	11.15	17,105
1994	949,912.22	674,058	659,627	290,285	11.66	24,896
1995	966,601.29	669,855	655,514	311,087	12.18	25,541
1996	673,200.91	454,949	445,209	227,992	12.71	17,938
1997	948,259.41	626,231	612,824	335,435	13.11	25,586
1998	795,939.00	510,913	499,975	295,964	13.67	21,651
1999	983,256.46	612,372	599,262	383,995	14.23	26,985
2000	880,960.43	533,157	521,743	359,218	14.68	24,470
2001	1,192,037.30	697,103	682,179	509,859	15.26	33,411
2002	847,129.96	477,612	467,387	379,743	15.86	23,943
2003	929,821.67	505,823	494,994	434,828	16.34	26,611
2004	863,382.20	450,426	440,783	422,599	16.96	24,917
2005	1,013,951.51	507,483	496,618	517,333	17.47	29,613
2006	1,174,539.07	562,017	549,985	624,554	17.98	34,736
2007	737,601.30	335,019	327,847	409,755	18.63	21,994
2008	2,956,224.78	1,272,950	1,245,698	1,710,527	19.17	89,229
2009	1,477,931.76	600,631	587,772	890,160	19.72	45,140
2010	1,684,501.39	642,132	628,385	1,056,117	20.29	52,051
2011	2,983,870.17	1,063,750	1,040,976	1,942,894	20.76	93,588
2012	2,546,878.79	839,706	821,729	1,725,150	21.35	80,803
2013	3,146,600.58	953,420	933,008	2,213,592	21.85	101,309
2014	3,224,667.26	885,494	866,537	2,358,131	22.46	104,992
2015	2,704,891.05	667,567	653,275	2,051,616	22.89	89,629
2016	3,350,696.08	727,436	711,862	2,638,834	23.44	112,578
2017	4,167,405.81	781,805	765,067	3,402,338	23.82	142,835
2018	7,771,410.32	1,217,003	1,190,948	6,580,462	24.24	271,471
2019	4,109,336.87	512,023	501,061	3,608,276	24.59	146,738
2020	4,623,092.72	424,400	415,314	4,207,779	24.75	170,011
2021	6,766,855.92	388,418	380,102	6,386,754	24.61	259,519
2022	4,453,379.43	93,521	91,519	4,361,861	23.31	187,124
	76,379,683.58	24,594,978	24,068,968	52,310,716		2,510,804

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1952	10,318.07	10,318	10,318			
1953	175.23	175	175			
1954	375.25	375	375			
1955	1,972.41	1,972	1,972			
1956	3,968.32	3,968	3,968			
1957	1,636.97	1,637	1,637			
1958	7,202.98	7,172	7,203			
1959	6,044.82	5,979	6,045			
1960	11,276.76	11,071	11,277			
1961	29,802.46	29,036	29,802			
1962	55,149.09	53,305	55,149			
1963	67,255.17	64,469	67,255			
1964	127,393.04	121,133	127,393			
1965	235,786.81	222,314	234,453	1,334	2.00	667
1966	346,543.81	323,869	341,553	4,991	2.29	2,179
1967	272,058.22	252,081	265,845	6,213	2.57	2,418
1968	319,741.18	293,615	309,647	10,094	2.86	3,529
1969	478,201.73	435,164	458,925	19,277	3.15	6,120
1970	418,042.48	376,953	397,536	20,507	3.44	5,961
1971	264,725.69	236,437	249,347	15,379	3.74	4,112
1972	268,278.15	237,389	250,351	17,927	4.03	4,448
1973	116,562.77	102,175	107,754	8,809	4.32	2,039
1974	36,317.52	31,524	33,245	3,072	4.62	665
1975	61,488.71	52,827	55,711	5,777	4.93	1,172
1976	26,516.86	22,547	23,778	2,739	5.24	523
1977	43,748.69	36,799	38,808	4,940	5.56	888
1978	38,041.86	31,651	33,379	4,663	5.88	793
1979	121,868.99	100,212	105,684	16,185	6.22	2,602
1980	912,715.82	741,390	781,872	130,844	6.57	19,915
1981	1,354,665.60	1,086,049	1,145,350	209,315	6.94	30,161
1982	104,189.72	89,041	93,903	10,287	6.89	1,493
1983	63,066.60	53,310	56,221	6,846	7.23	947
1984	271,442.18	226,763	239,145	32,297	7.59	4,255
1985	516,965.52	428,461	451,856	65,109	7.75	8,401
1986	600,906.62	491,301	518,127	82,779	8.14	10,169
1987	605,001.54	487,510	514,129	90,872	8.56	10,616
1988	665,483.86	528,061	556,895	108,589	8.98	12,092
1989	651,209.85	508,334	536,090	115,119	9.42	12,221
1990	695,729.35	533,624	562,761	132,968	9.87	13,472
1991	880,151.46	662,578	698,757	181,395	10.34	17,543
1992	1,241,475.01	916,333	966,367	275,108	10.82	25,426
1993	1,380,383.91	1,001,745	1,056,443	323,941	11.15	29,053

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1994	2,316,407.65	1,643,723	1,733,475	582,933	11.66	49,994
1995	490,609.75	339,993	358,558	132,052	12.18	10,842
1996	1,224,040.87	827,207	872,375	351,666	12.71	27,668
1997	1,202,719.43	794,276	837,646	365,074	13.11	27,847
1998	1,528,065.28	980,865	1,034,423	493,642	13.67	36,111
1999	768,998.37	478,932	505,083	263,915	14.23	18,546
2000	837,803.51	507,039	534,725	303,079	14.68	20,646
2001	1,038,802.06	607,491	640,662	398,140	15.26	26,090
2002	1,039,266.00	585,938	617,932	421,334	15.86	26,566
2003	604,247.96	328,711	346,660	257,588	16.34	15,764
2004	1,842,004.63	960,974	1,013,446	828,559	16.96	48,854
2005	1,247,033.47	624,140	658,220	588,814	17.47	33,704
2006	1,309,132.40	626,420	660,624	648,508	17.98	36,068
2007	1,837,672.23	834,671	880,246	957,426	18.63	51,392
2008	1,428,924.55	615,295	648,892	780,033	19.17	40,690
2009	1,473,820.76	598,961	631,666	842,155	19.72	42,706
2010	994,815.31	379,224	399,931	594,885	20.29	29,319
2011	1,920,851.75	684,784	722,175	1,198,677	20.76	57,740
2012	1,408,839.28	464,494	489,857	918,983	21.35	43,044
2013	1,339,930.93	405,999	428,168	911,763	21.85	41,728
2014	1,615,166.72	443,525	467,743	1,147,424	22.46	51,087
2015	1,655,050.07	408,466	430,769	1,224,281	22.89	53,485
2016	1,322,977.74	287,218	302,901	1,020,077	23.44	43,519
2017	2,717,167.51	509,741	537,574	2,179,593	23.82	91,503
2018	4,292,751.88	672,245	708,951	3,583,800	24.24	147,847
2019	2,112,746.33	263,248	277,622	1,835,124	24.59	74,629
2020	3,922,805.16	360,114	379,777	3,543,028	24.75	143,153
2021	2,958,080.18	169,794	179,065	2,779,015	24.61	112,922
2022	4,673,645.81	98,147	103,506	4,570,140	23.31	196,059
	64,438,258.67	27,322,302	28,809,175	35,629,084		1,833,403
CPG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1967	4,892.78	4,534	3,539	1,354	2.57	527
1968	10,326.83	9,483	7,401	2,925	2.86	1,023
1969	22,443.69	20,424	15,941	6,503	3.15	2,064
1970	17,704.49	15,964	12,460	5,245	3.44	1,525
1971	17,665.44	15,778	12,315	5,351	3.74	1,431

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1972	46,115.44	40,806	31,849	14,266	4.03	3,540
1973	66,671.02	58,442	45,614	21,057	4.32	4,874
1974	37,805.85	32,815	25,612	12,194	4.62	2,639
1975	41,564.96	35,710	27,872	13,693	4.93	2,777
1976	28,908.64	24,581	19,186	9,723	5.24	1,856
1977	16,006.80	13,464	10,509	5,498	5.56	989
1978	7,984.09	6,643	5,185	2,799	5.88	476
1979	17,726.48	14,576	11,377	6,350	6.22	1,021
1980	70,419.98	57,201	44,645	25,775	6.57	3,923
1981	30,788.91	24,684	19,266	11,523	6.94	1,660
1982	65,435.31	55,921	43,646	21,789	6.89	3,162
1983	59,448.54	50,252	39,222	20,227	7.23	2,798
1984	45,400.39	37,927	29,602	15,798	7.59	2,081
1985	60,065.12	49,782	38,855	21,210	7.75	2,737
1986	80,400.85	65,736	51,307	29,094	8.14	3,574
1987	63,019.12	50,781	39,635	23,384	8.56	2,732
1988	10,043.66	7,970	6,221	3,823	8.98	426
1989	26,621.02	20,780	16,219	10,402	9.42	1,104
1990	148,340.72	113,777	88,803	59,538	9.87	6,032
1991	166,275.15	125,172	97,697	68,578	10.34	6,632
1992	147,895.48	109,162	85,201	62,694	10.82	5,794
1993	81,792.41	59,357	46,328	35,464	11.15	3,181
1994	57,351.34	40,697	31,764	25,587	11.66	2,194
1996	22,972.75	15,525	12,117	10,855	12.71	854
1997	15,665.94	10,346	8,075	7,591	13.11	579
2001	4,059.49	2,374	1,853	2,207	15.26	145
2002	3,572.37	2,014	1,572	2,000	15.86	126
2003	14,192.29	7,721	6,026	8,166	16.34	500
2004	99,496.99	51,908	40,514	58,983	16.96	3,478
2005	44,185.75	22,115	17,261	26,925	17.47	1,541
2006	83,314.25	39,866	31,115	52,199	17.98	2,903
2007	43,768.16	19,879	15,516	28,253	18.63	1,517
2008	80,370.28	34,607	27,011	53,359	19.17	2,783
2009	725.64	295	230	495	19.72	25
2012	630,065.13	207,732	162,135	467,930	21.35	21,917
2013	1,169,528.53	354,367	276,584	892,945	21.85	40,867
2014	707,467.06	194,270	151,628	555,839	22.46	24,748
2015	623,055.80	153,770	120,018	503,038	22.89	21,976
2016	568,970.09	123,523	96,410	472,560	23.44	20,160
2017	926,430.19	173,798	135,650	790,781	23.82	33,198
2018	660,439.67	103,425	80,723	579,716	24.24	23,916
2019	1,215,481.07	151,449	118,206	1,097,275	24.59	44,623

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
2020	771,235.15	70,799	55,259	715,976	24.75	28,928
2021	817,464.59	46,922	36,623	780,842	24.61	31,729
2022	1,920,102.06	40,322	31,471	1,888,631	23.31	81,022
	11,871,677.76	2,989,446	2,333,267	9,538,411		460,307
	152,689,620.01	54,906,726	55,211,410	97,478,211		4,804,514

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.3 3.15

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1995	225,308.19	219,946	225,308			
1996	173,108.40	167,430	173,108			
1997	173,127.78	166,445	173,128			
1998	184,130.59	175,476	184,131			
1999	342,667.80	322,930	342,668			
2000	478,162.92	446,509	476,262	1,901	1.60	1,188
2001	549,785.70	505,913	539,624	10,161	1.86	5,463
2002	670,198.61	608,674	649,233	20,966	2.07	10,129
2003	252,157.11	225,202	240,208	11,949	2.33	5,128
2004	243,716.21	213,715	227,956	15,760	2.60	6,062
2005	216,895.80	185,988	198,381	18,515	2.91	6,363
2006	5,390,842.80	4,500,815	4,800,726	590,117	3.26	181,017
2008	15,525.65	12,157	12,967	2,559	4.02	637
2018	303,687.22	86,095	91,832	211,855	11.37	18,633
2020	1,511,975.32	238,590	254,488	1,257,487	13.35	94,194
	10,731,290.10	8,075,885	8,590,021	2,141,269		328,814
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1999	68,566.40	64,617	68,566			
2000	110,387.90	103,080	110,388			
2001	719,557.21	662,137	719,557			
2002	1,586,309.09	1,440,686	1,583,640	2,669	2.07	1,289
2003	887,157.53	792,320	870,939	16,218	2.33	6,961
2004	2,657,385.83	2,330,262	2,561,486	95,900	2.60	36,885
2005	1,150,682.48	986,710	1,084,618	66,065	2.91	22,703
2006	1,163,903.88	971,743	1,068,166	95,738	3.26	29,367
2007	1,417,138.09	1,148,732	1,262,717	154,421	3.62	42,658
2008	490,501.02	384,062	422,171	68,330	4.02	16,998
2009	57,248.17	42,970	47,234	10,014	4.49	2,230
2010	228,321.73	162,976	179,148	49,174	5.01	9,815
2011	246,330.80	165,731	182,176	64,155	5.59	11,477
2012	96,274.94	60,451	66,449	29,826	6.22	4,795
2013	68,490.16	39,560	43,485	25,005	6.95	3,598
2014	7,274.22	3,815	4,194	3,081	7.71	400
2016	42,352.64	17,263	18,976	23,377	9.45	2,474
2018	197,444.20	55,975	61,529	135,915	11.37	11,954

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2019	24,280.90	5,361	5,893	18,388	12.35	1,489
2020	67,776.24	10,695	11,756	56,020	13.35	4,196
2021	829,106.03	78,433	86,216	742,890	14.35	51,769
	12,116,489.46	9,527,579	10,459,303	1,657,186		261,058
CPG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2010	396,383.10	282,938	314,961	81,422	5.01	16,252
2020	5,164.22	815	907	4,257	13.35	319
	401,547.32	283,753	315,868	85,679		16,571
	23,249,326.88	17,887,217	19,365,192	3,884,134		606,443

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.4   2.61

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1906	25.97	26	26			
1907	159.97	160	160			
1908	93.03	93	93			
1909	3,121.71	3,122	3,122			
1910	658.69	659	659			
1911	1,418.49	1,418	1,418			
1912	918.21	918	918			
1913	1,239.88	1,240	1,240			
1914	1,076.18	1,076	1,076			
1915	1,468.00	1,468	1,468			
1916	1,902.75	1,903	1,903			
1917	2,465.82	2,466	2,466			
1918	1,664.15	1,664	1,664			
1919	7,981.32	7,981	7,981			
1920	10,999.50	11,000	11,000			
1921	9,308.14	9,308	9,308			
1922	10,276.68	10,277	10,277			
1923	11,862.52	11,863	11,863			
1924	14,757.37	14,757	14,757			
1925	15,669.62	15,670	15,670			
1926	10,597.52	10,598	10,598			
1927	12,434.34	12,434	12,434			
1928	11,083.35	11,083	11,083			
1929	11,684.32	11,684	11,684			
1930	7,162.15	7,162	7,162			
1931	5,507.03	5,485	5,507			
1932	3,904.95	3,870	3,905			
1933	2,118.10	2,088	2,118			
1934	2,611.15	2,558	2,611			
1935	3,432.35	3,343	3,432			
1936	3,543.59	3,430	3,544			
1937	6,124.11	5,892	6,124			
1938	4,986.37	4,768	4,986			
1939	6,044.36	5,745	6,044			
1940	8,334.79	7,871	8,335			
1941	10,064.47	9,443	10,064			
1942	7,992.04	7,450	7,992			
1943	5,837.40	5,405	5,837			
1944	7,703.33	7,085	7,703			
1945	8,046.39	7,350	8,046			
1946	12,765.36	11,580	12,706	59	4.27	14
1947	26,949.45	24,278	26,639	310	4.56	68

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1948	25,272.06	22,602	24,800	472	4.86	97
1949	30,294.42	26,896	29,512	783	5.16	152
1950	36,202.96	31,906	35,009	1,194	5.46	219
1951	42,070.88	36,803	40,382	1,689	5.76	293
1952	46,652.20	40,496	44,434	2,218	6.07	365
1953	40,354.84	34,758	38,138	2,217	6.38	347
1954	55,376.64	47,323	51,925	3,451	6.69	516
1955	68,528.45	58,085	63,734	4,795	7.01	684
1956	74,595.82	62,725	68,825	5,771	7.32	788
1957	77,337.55	64,476	70,746	6,591	7.65	862
1958	72,451.04	59,898	65,723	6,728	7.97	844
1959	78,822.72	64,601	70,884	7,939	8.30	957
1960	75,974.10	61,721	67,723	8,251	8.63	956
1961	65,723.24	52,907	58,052	7,671	8.97	855
1962	58,233.96	46,448	50,965	7,269	9.31	781
1963	67,376.47	53,242	58,420	8,957	9.65	928
1964	76,433.22	59,817	65,634	10,799	10.00	1,080
1965	93,981.82	72,836	79,919	14,062	10.35	1,359
1966	97,733.00	74,978	82,270	15,463	10.71	1,444
1967	107,627.92	81,727	89,675	17,953	11.07	1,622
1968	124,056.33	93,204	102,268	21,788	11.44	1,905
1969	127,255.47	94,584	103,782	23,473	11.81	1,988
1970	112,838.63	82,936	91,002	21,837	12.19	1,791
1971	99,318.90	72,179	79,199	20,120	12.57	1,601
1972	91,307.99	65,583	71,961	19,347	12.96	1,493
1973	124,309.34	88,232	96,813	27,497	13.35	2,060
1974	132,172.12	92,665	101,677	30,495	13.75	2,218
1975	91,004.16	63,010	69,138	21,866	14.15	1,545
1976	47,391.99	32,391	35,541	11,851	14.56	814
1977	81,921.71	55,244	60,617	21,305	14.98	1,422
1978	95,802.96	63,730	69,928	25,875	15.40	1,680
1979	300,973.70	197,400	216,597	84,376	15.83	5,330
1980	568,703.65	367,553	403,298	165,406	16.27	10,166
1981	642,245.29	408,943	448,713	193,532	16.71	11,582
1982	515,909.71	376,098	412,674	103,236	15.06	6,855
1983	536,016.90	385,343	422,818	113,199	15.45	7,327
1984	469,337.03	332,478	364,812	104,525	15.85	6,595
1985	659,120.68	462,175	507,122	151,998	15.98	9,512
1986	674,619.95	465,353	510,609	164,011	16.41	9,995
1987	755,342.67	512,122	561,927	193,416	16.86	11,472
1988	973,462.49	648,131	711,163	262,300	17.32	15,144
1989	1,057,228.22	694,176	761,686	295,543	17.52	16,869

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1990	1,319,304.76	848,973	931,537	387,768	18.01	21,531
1991	1,313,610.24	831,778	912,670	400,941	18.25	21,969
1992	1,231,983.19	762,844	837,032	394,952	18.76	21,053
1993	957,447.29	581,841	638,426	319,021	19.04	16,755
1994	1,359,038.63	805,638	883,987	475,051	19.58	24,262
1995	1,502,845.46	871,951	956,749	546,096	19.90	27,442
1996	1,399,242.42	789,732	866,535	532,708	20.45	26,049
1997	1,648,204.88	907,831	996,119	652,086	20.80	31,350
1998	1,822,480.25	977,943	1,073,049	749,431	21.16	35,417
1999	1,789,437.56	933,550	1,024,339	765,098	21.55	35,503
2000	1,823,448.15	919,018	1,008,394	815,054	22.14	36,814
2001	1,769,881.51	863,702	947,698	822,183	22.56	36,444
2002	1,023,698.40	482,674	529,615	494,084	22.98	21,501
2003	1,423,757.52	646,955	709,872	713,885	23.42	30,482
2004	1,118,296.92	488,248	535,731	582,566	23.87	24,406
2005	1,292,419.66	540,490	593,053	699,366	24.34	28,733
2006	1,356,615.53	539,390	591,846	764,769	25.00	30,591
2007	7,166,610.15	2,710,412	2,974,003	4,192,607	25.48	164,545
2008	3,015,568.37	1,080,177	1,185,226	1,830,343	25.98	70,452
2009	2,211,609.49	746,418	819,008	1,392,601	26.50	52,551
2010	1,434,935.75	453,727	497,853	937,083	27.03	34,668
2011	1,796,958.30	529,025	580,473	1,216,485	27.56	44,140
2012	2,217,366.79	600,685	659,102	1,558,264	28.26	55,140
2013	2,733,296.92	677,858	743,781	1,989,516	28.81	69,056
2014	2,028,701.98	453,618	497,733	1,530,969	29.52	51,862
2015	2,705,625.03	539,772	592,266	2,113,359	30.09	70,235
2016	2,888,132.55	503,113	552,041	2,336,091	30.81	75,822
2017	2,911,115.42	432,301	474,343	2,436,773	31.54	77,260
2018	3,945,888.00	482,977	529,947	3,415,941	32.26	105,888
2019	2,997,175.31	287,429	315,382	2,681,793	33.00	81,266
2020	3,215,607.89	221,234	242,749	2,972,859	33.86	87,799
2021	5,478,116.11	226,794	248,850	5,229,266	34.73	150,569
2022	4,788,775.74	66,085	72,512	4,716,264	35.60	132,479
	85,534,574.29	29,779,629	32,657,664	52,876,910		1,938,629

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2022	305,513.07	4,216	45,978-	351,491	35.60	9,873
	305,513.07	4,216	45,978-	351,491		9,873
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1953	3,759.31	3,238	2,110	1,649	6.38	258
1954	4,769.04	4,075	2,656	2,113	6.69	316
1955	6,456.72	5,473	3,567	2,890	7.01	412
1956	4,456.50	3,747	2,442	2,015	7.32	275
1957	12,058.90	10,054	6,552	5,507	7.65	720
1958	13,140.51	10,864	7,080	6,060	7.97	760
1959	13,621.77	11,164	7,276	6,346	8.30	765
1960	5,483.24	4,455	2,903	2,580	8.63	299
1961	14,082.83	11,337	7,388	6,695	8.97	746
1962	11,610.10	9,260	6,035	5,575	9.31	599
1963	12,081.97	9,547	6,222	5,860	9.65	607
1964	15,068.94	11,793	7,685	7,383	10.00	738
1965	23,021.85	17,842	11,628	11,394	10.35	1,101
1966	17,063.23	13,090	8,531	8,532	10.71	797
1967	20,271.37	15,393	10,032	10,240	11.07	925
1968	26,534.74	19,936	12,992	13,542	11.44	1,184
1969	19,112.57	14,206	9,258	9,855	11.81	834
1970	36,494.31	26,823	17,481	19,014	12.19	1,560
1971	23,141.06	16,818	10,960	12,181	12.57	969
1972	19,994.27	14,361	9,359	10,635	12.96	821
1973	10,199.39	7,239	4,718	5,482	13.35	411
1974	78,281.57	54,882	35,767	42,515	13.75	3,092
1975	19,322.73	13,379	8,719	10,604	14.15	749
1976	4,284.03	2,928	1,908	2,376	14.56	163
1977	1,305.98	881	574	732	14.98	49
1978	108.54	72	47	62	15.40	4
1979	933.34	612	399	535	15.83	34
1980	13,373.94	8,644	5,633	7,741	16.27	476
1981	35,146.21	22,379	14,584	20,562	16.71	1,231
1982	32,391.30	23,613	15,389	17,003	15.06	1,129
1983	29,782.09	21,410	13,953	15,829	15.45	1,025
1984	30,665.51	21,723	14,157	16,509	15.85	1,042
1985	52,778.10	37,008	24,118	28,660	15.98	1,793

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1986	57,832.47	39,893	25,998	31,834	16.41	1,940
1987	73,374.91	49,748	32,421	40,954	16.86	2,429
1988	56,213.02	37,427	24,391	31,822	17.32	1,837
1989	78,349.18	51,444	33,526	44,823	17.52	2,558
1990	82,461.83	53,064	34,582	47,880	18.01	2,659
1991	85,017.85	53,833	35,083	49,935	18.25	2,736
1992	69,268.37	42,891	27,952	41,316	18.76	2,202
1993	75,642.17	45,968	29,957	45,685	19.04	2,399
1994	101,749.30	60,317	39,309	62,441	19.58	3,189
1995	110,148.34	63,908	41,649	68,500	19.90	3,442
1996	204,811.68	115,596	75,334	129,478	20.45	6,331
1997	302,161.08	166,430	108,462	193,699	20.80	9,312
1998	537,354.98	288,345	187,914	349,441	21.16	16,514
1999	408,740.44	213,240	138,968	269,772	21.55	12,518
2000	390,443.38	196,783	128,243	262,200	22.14	11,843
2001	342,475.63	167,128	108,917	233,558	22.56	10,353
2002	450,715.35	212,512	138,494	312,222	22.98	13,587
2003	349,203.83	158,678	103,410	245,794	23.42	10,495
2004	243,531.47	106,326	69,293	174,239	23.87	7,299
2005	427,311.91	178,702	116,460	310,852	24.34	12,771
2006	298,018.15	118,492	77,221	220,797	25.00	8,832
2007	645,293.82	244,050	159,047	486,247	25.48	19,083
2008	811,810.63	290,791	189,508	622,302	25.98	23,953
2009	472,883.54	159,598	104,010	368,874	26.50	13,920
2010	329,246.00	104,108	67,847	261,399	27.03	9,671
2011	617,879.10	181,904	118,547	499,332	27.56	18,118
2012	571,596.15	154,845	100,912	470,684	28.26	16,655
2013	631,463.43	156,603	102,058	529,405	28.81	18,376
2014	754,838.20	168,782	109,995	644,843	29.52	21,844
2015	1,062,863.72	212,041	138,187	924,677	30.09	30,730
2016	2,026,993.13	353,102	230,116	1,796,877	30.81	58,321
2017	650,479.93	96,596	62,952	587,528	31.54	18,628
2018	757,360.90	92,701	60,413	696,948	32.26	21,604
2019	1,538,028.17	147,497	96,124	1,441,905	33.00	43,694

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2020	484,320.49	33,321	21,715	462,605	33.86	13,662
2021	357,003.29	14,780	9,632	347,371	34.73	10,002
2022	708,939.16	9,783	6,376	702,564	35.60	19,735
	17,776,620.96	5,289,473	3,447,144	14,329,477		529,126
	103,616,708.32	35,073,318	36,058,830	67,557,878		2,477,628

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.3 2.39

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1944	77.63	71	78			
1957	116.81	97	117			
1962	2,147.42	1,713	2,135	12	9.31	1
1964	17,889.06	14,000	17,453	436	10.00	44
1965	20,883.98	16,185	20,177	707	10.35	68
1966	29,708.82	22,792	28,413	1,296	10.71	121
1967	33,819.48	25,681	32,015	1,805	11.07	163
1968	27,850.03	20,924	26,084	1,766	11.44	154
1969	29,267.04	21,753	27,118	2,149	11.81	182
1970	46,379.62	34,089	42,496	3,883	12.19	319
1971	42,371.23	30,793	38,387	3,984	12.57	317
1972	30,556.56	21,948	27,361	3,196	12.96	247
1973	21,499.83	15,260	19,023	2,476	13.35	185
1974	24,263.37	17,011	21,206	3,057	13.75	222
1975	33,405.40	23,130	28,834	4,571	14.15	323
1976	7,079.30	4,839	6,032	1,047	14.56	72
1977	17,762.55	11,978	14,932	2,830	14.98	189
1978	23,226.72	15,451	19,262	3,965	15.40	257
1979	85,029.47	55,768	69,522	15,508	15.83	980
1980	174,936.13	113,061	140,945	33,992	16.27	2,089
1981	85,136.64	54,210	67,579	17,557	16.71	1,051
1982	129,302.42	94,261	117,508	11,794	15.06	783
1983	63,079.38	45,348	56,532	6,547	15.45	424
1984	58,822.74	41,670	51,947	6,876	15.85	434
1985	123,279.20	86,443	107,762	15,517	15.98	971
1986	140,259.52	96,751	120,612	19,647	16.41	1,197
1987	136,726.58	92,701	115,563	21,163	16.86	1,255
1988	175,358.43	116,754	145,548	29,810	17.32	1,721
1989	213,352.92	140,088	174,637	38,716	17.52	2,210
1990	213,985.49	137,700	171,660	42,325	18.01	2,350
1991	78,221.08	49,530	61,745	16,476	18.25	903
1992	96,631.56	59,834	74,590	22,041	18.76	1,175
1993	33,943.13	20,627	25,714	8,229	19.04	432
1994	111,681.31	66,205	82,533	29,149	19.58	1,489
1995	158,863.82	92,173	114,905	43,959	19.90	2,209
1996	44,710.50	25,235	31,459	13,252	20.45	648
1997	90,352.27	49,766	62,039	28,313	20.80	1,361
1998	55,881.99	29,986	37,381	18,501	21.16	874
1999	104,435.10	54,484	67,921	36,514	21.55	1,694
2000	92,841.48	46,792	58,332	34,509	22.14	1,559
2001	170,283.81	83,098	103,592	66,692	22.56	2,956
2002	54,797.23	25,837	32,209	22,588	22.98	983

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2003	133,154.30	60,505	75,427	57,727	23.42	2,465
2004	229,722.81	100,297	125,033	104,690	23.87	4,386
2005	221,269.27	92,535	115,356	105,913	24.34	4,351
2006	179,479.91	71,361	88,960	90,520	25.00	3,621
2008	542,805.95	194,433	242,385	300,421	25.98	11,564
2009	435,389.76	146,944	183,184	252,206	26.50	9,517
2010	540,079.19	170,773	212,890	327,189	27.03	12,105
2012	185,668.57	50,298	62,703	122,966	28.26	4,351
2013	64,886.52	16,092	20,061	44,826	28.81	1,556
2020	588,926.94	40,518	50,511	538,416	33.86	15,901
2021	64,272.07	2,661	3,317	60,955	34.73	1,755
2022	30,000.48	414	516	29,484	35.60	828
	6,315,872.82	2,922,868	3,643,702	2,672,171		107,012
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1950	210.83	186	211			
1952	22,819.32	19,808	22,819			
1953	3,317.14	2,857	3,317			
1954	3,630.76	3,103	3,631			
1956	2,284.19	1,921	2,284			
1957	4,304.02	3,588	4,304			
1958	522.23	432	522			
1959	5,067.00	4,153	5,067			
1960	13,550.46	11,008	13,550			
1961	9,248.90	7,445	9,249			
1962	28,639.95	22,844	28,640			
1963	14,445.64	11,415	14,446			
1964	37,738.37	29,534	37,738			
1965	38,315.09	29,694	38,315			
1966	31,195.39	23,932	31,195			
1967	24,164.12	18,349	24,164			
1968	19,859.30	14,920	19,859			
1969	19,924.39	14,809	19,763	162	11.81	14
1970	22,729.87	16,706	22,294	436	12.19	36
1971	20,261.33	14,725	19,651	611	12.57	49
1972	17,271.56	12,405	16,555	717	12.96	55
1973	11,477.26	8,146	10,871	606	13.35	45

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

PNG
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1974	24,387.93	17,098	22,817	1,571	13.75	114
1975	16,298.98	11,285	15,060	1,239	14.15	88
1976	24,993.78	17,083	22,797	2,196	14.56	151
1977	43,069.11	29,044	38,759	4,310	14.98	288
1978	25,951.28	17,263	23,038	2,914	15.40	189
1979	50,262.18	32,965	43,992	6,270	15.83	396
1980	157,477.54	101,778	135,823	21,654	16.27	1,331
1981	85,175.15	54,234	72,376	12,800	16.71	766
1984	250.78	178	238	13	15.85	1
1985	76,884.73	53,912	71,946	4,939	15.98	309
1986	6,292.30	4,340	5,792	501	16.41	31
1987	4,514.24	3,061	4,085	429	16.86	25
1988	436.49	291	388	48	17.32	3
1989	61,371.98	40,297	53,777	7,595	17.52	434
1990	113,156.99	72,817	97,175	15,982	18.01	887
1991	3,008.09	1,905	2,542	466	18.25	26
1992	70,116.05	43,416	57,939	12,177	18.76	649
1993	67,071.42	40,759	54,393	12,678	19.04	666
1994	82,550.42	48,936	65,305	17,245	19.58	881
1995	26,767.64	15,531	20,726	6,041	19.90	304
1996	1,224.75	691	922	303	20.45	15
1997	216,602.43	119,305	159,213	57,389	20.80	2,759
1998	256,637.82	137,712	183,777	72,860	21.16	3,443
1999	8,426.90	4,396	5,866	2,560	21.55	119
2000	84,558.06	42,617	56,873	27,685	22.14	1,250
2001	118,324.37	57,742	77,057	41,267	22.56	1,829
2002	169,502.89	79,921	106,655	62,848	22.98	2,735
2003	148,249.29	67,364	89,898	58,352	23.42	2,492
2004	220,051.45	96,074	128,211	91,840	23.87	3,848
2007	122,119.93	46,186	61,635	60,484	25.48	2,374
2009	114,048.46	38,491	51,366	62,682	26.50	2,365
2010	62,512.30	19,766	26,378	36,134	27.03	1,337
2018	45.98	6	8	38	32.26	1
2021	6,060.88	251	335	5,726	34.73	165
2022	19,000.05	262	350	18,650	35.60	524
	2,838,379.76	1,588,957	2,105,958	732,422		32,994

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1971	4,984.87	3,623	4,809	176	12.57	14
1972	12,026.83	8,638	11,466	561	12.96	43
1973	16,107.57	11,433	15,176	931	13.35	70
1974	23,538.94	16,503	21,906	1,633	13.75	119
1975	11,899.56	8,239	10,937	963	14.15	68
1976	6,602.06	4,512	5,989	613	14.56	42
1977	3,874.03	2,612	3,467	407	14.98	27
1978	5,216.40	3,470	4,606	610	15.40	40
1979	5,691.51	3,733	4,955	736	15.83	46
1980	25,161.69	16,262	21,586	3,575	16.27	220
1981	21,884.01	13,934	18,496	3,388	16.71	203
1982	13,762.96	10,033	13,318	445	15.06	30
1983	18,482.93	13,287	17,637	846	15.45	55
1984	28,946.74	20,506	27,220	1,727	15.85	109
1985	25,122.56	17,616	23,384	1,739	15.98	109
1986	26,997.74	18,623	24,720	2,277	16.41	139
1987	27,418.88	18,590	24,677	2,742	16.86	163
1988	27,140.50	18,070	23,986	3,154	17.32	182
1989	33,172.62	21,781	28,912	4,260	17.52	243
1990	49,192.80	31,656	42,021	7,172	18.01	398
1991	52,673.92	33,353	44,273	8,401	18.25	460
1992	51,148.42	31,671	42,040	9,108	18.76	486
1993	54,521.25	33,133	43,981	10,540	19.04	554
1994	58,336.06	34,582	45,905	12,431	19.58	635
1995	71,955.57	41,749	55,418	16,537	19.90	831
1996	66,491.84	37,528	49,815	16,677	20.45	816
1997	69,553.69	38,310	50,853	18,701	20.80	899
1998	43,049.88	23,101	30,665	12,385	21.16	585
1999	67,866.40	35,406	46,998	20,868	21.55	968
2000	15,180.20	7,651	10,156	5,024	22.14	227
2001	23,560.41	11,497	15,261	8,299	22.56	368
2002	27,353.46	12,897	17,120	10,234	22.98	445
2003	3,463.18	1,574	2,089	1,374	23.42	59
2004	30,490.94	13,312	17,671	12,820	23.87	537
2005	306.76	128	170	137	24.34	6
2006	27,843.60	11,071	14,696	13,148	25.00	526
2007	1,441.53	545	723	718	25.48	28
2008	23,298.67	8,346	11,079	12,220	25.98	470
2009	15,654.65	5,283	7,013	8,642	26.50	326
2010	25,700.89	8,127	10,788	14,913	27.03	552
2011	17,910.55	5,273	6,999	10,911	27.56	396
2012	25,073.22	6,792	9,016	16,057	28.26	568

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2013	43,111.12	10,692	14,193	28,918	28.81	1,004
2014	31,961.03	7,146	9,486	22,475	29.52	761
2015	28,081.54	5,602	7,436	20,645	30.09	686
2016	18,470.60	3,218	4,272	14,199	30.81	461
2017	39,901.56	5,925	7,865	32,037	31.54	1,016
2018	118,881.42	14,551	19,315	99,566	32.26	3,086
2019	2,661.67	255	338	2,323	33.00	70
2020	28,753.70	1,978	2,626	26,128	33.86	772
2021	22,635.59	937	1,244	21,392	34.73	616
2022	16,999.20	235	312	16,687	35.60	469
	1,511,557.72	714,989	949,085	562,473		22,003
	10,665,810.30	5,226,814	6,698,745	3,967,066		162,009

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.5 1.52

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1906	714.41	714	714			
1907	1,561.26	1,561	1,561			
1908	723.45	723	723			
1909	1,046.39	1,046	1,046			
1910	430.52	431	431			
1911	932.52	933	933			
1912	1,206.80	1,207	1,207			
1913	1,055.95	1,056	1,056			
1914	1,068.20	1,068	1,068			
1915	677.35	677	677			
1916	1,296.19	1,296	1,296			
1917	1,460.81	1,461	1,461			
1918	866.02	866	866			
1919	1,273.27	1,273	1,273			
1920	1,227.62	1,228	1,228			
1921	1,807.89	1,808	1,808			
1922	3,053.22	3,053	3,053			
1923	4,351.68	4,352	4,352			
1924	4,447.12	4,447	4,447			
1925	4,648.53	4,649	4,649			
1926	4,202.25	4,202	4,202			
1927	4,120.04	4,120	4,120			
1928	3,275.70	3,276	3,276			
1929	3,723.76	3,724	3,724			
1930	2,604.15	2,604	2,604			
1931	2,091.19	2,083	2,091			
1932	1,054.06	1,045	1,054			
1933	912.46	899	912			
1934	1,079.78	1,058	1,080			
1935	1,148.99	1,119	1,149			
1936	1,480.42	1,433	1,480			
1937	1,944.70	1,871	1,945			
1938	1,534.17	1,467	1,534			
1939	1,506.52	1,432	1,507			
1940	1,699.00	1,604	1,699			
1941	2,084.63	1,956	2,085			
1942	1,817.12	1,694	1,817			
1943	1,192.20	1,104	1,192			
1944	2,318.25	2,132	2,318			
1945	2,576.02	2,353	2,559	17	3.98	4
1946	3,958.87	3,591	3,906	53	4.27	12
1947	8,509.55	7,666	8,338	172	4.56	38

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

UGI-GAS
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1948	8,189.87	7,325	7,967	223	4.86	46
1949	9,437.63	8,379	9,113	325	5.16	63
1950	9,865.21	8,694	9,456	410	5.46	75
1951	12,889.17	11,275	12,263	626	5.76	109
1952	13,415.30	11,645	12,665	750	6.07	124
1953	10,851.74	9,347	10,166	686	6.38	108
1954	9,150.18	7,819	8,504	646	6.69	97
1955	14,876.97	12,610	13,715	1,162	7.01	166
1956	19,083.64	16,047	17,453	1,631	7.32	223
1957	20,925.66	17,446	18,974	1,951	7.65	255
1958	19,920.19	16,469	17,912	2,009	7.97	252
1959	28,290.18	23,186	25,217	3,073	8.30	370
1960	21,265.70	17,276	18,789	2,476	8.63	287
1961	14,096.59	11,348	12,342	1,755	8.97	196
1962	14,535.34	11,594	12,610	1,926	9.31	207
1963	17,768.88	14,041	15,271	2,498	9.65	259
1964	20,167.31	15,783	17,166	3,002	10.00	300
1965	21,206.42	16,435	17,875	3,332	10.35	322
1966	22,581.92	17,324	18,842	3,740	10.71	349
1967	24,306.87	18,457	20,074	4,233	11.07	382
1968	28,987.11	21,778	23,686	5,301	11.44	463
1969	29,942.35	22,255	24,205	5,738	11.81	486
1970	24,533.84	18,032	19,612	4,922	12.19	404
1971	31,877.14	23,166	25,195	6,682	12.57	532
1972	37,880.83	27,208	29,591	8,289	12.96	640
1973	46,395.34	32,930	35,815	10,581	13.35	793
1974	41,027.16	28,764	31,284	9,743	13.75	709
1975	28,351.55	19,630	21,350	7,002	14.15	495
1976	20,587.75	14,071	15,304	5,284	14.56	363
1977	30,223.10	20,381	22,166	8,057	14.98	538
1978	40,544.05	26,971	29,334	11,210	15.40	728
1979	68,465.97	44,905	48,839	19,627	15.83	1,240
1980	130,733.22	84,493	91,895	38,839	16.27	2,387
1981	110,082.85	70,094	76,234	33,849	16.71	2,026
1982	189,427.07	138,092	150,189	39,238	15.06	2,605
1983	140,884.63	101,282	110,154	30,730	15.45	1,989
1984	96,163.92	68,123	74,091	22,073	15.85	1,393
1985	156,675.32	109,861	119,485	37,190	15.98	2,327
1986	142,373.20	98,209	106,812	35,561	16.41	2,167
1987	167,661.99	113,675	123,633	44,029	16.86	2,611
1988	176,200.73	117,314	127,591	48,610	17.32	2,807
1989	244,942.05	160,829	174,918	70,024	17.52	3,997

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1990	199,566.39	128,421	139,671	59,896	18.01	3,326
1991	127,505.58	80,737	87,810	39,696	18.25	2,175
1992	193,634.76	119,899	130,402	63,233	18.76	3,371
1993	110,056.58	66,881	72,740	37,317	19.04	1,960
1994	158,810.08	94,143	102,390	56,420	19.58	2,882
1995	224,978.07	130,532	141,967	83,011	19.90	4,171
1996	145,810.96	82,296	89,505	56,306	20.45	2,753
1997	183,254.44	100,937	109,779	73,475	20.80	3,532
1998	242,482.19	130,116	141,514	100,968	21.16	4,772
1999	162,687.05	84,874	92,309	70,378	21.55	3,266
2000	129,469.54	65,253	70,969	58,500	22.14	2,642
2001	175,056.32	85,427	92,910	82,146	22.56	3,641
2002	177,857.74	83,860	91,206	86,652	22.98	3,771
2003	462,984.13	210,380	228,809	234,175	23.42	9,999
2004	582,160.09	254,171	276,436	305,724	23.87	12,808
2005	461,061.88	192,816	209,707	251,355	24.34	10,327
2006	270,926.58	107,720	117,156	153,770	25.00	6,151
2008	800,679.28	286,803	311,927	488,752	25.98	18,813
2009	189,200.81	63,855	69,449	119,752	26.50	4,519
2010	213,558.77	67,527	73,442	140,116	27.03	5,184
2011	310,646.24	91,454	99,465	211,181	27.56	7,663
2012	513,992.66	139,241	151,439	362,554	28.26	12,829
2013	417,895.95	103,638	112,717	305,179	28.81	10,593
2014	466,769.23	104,370	113,513	353,256	29.52	11,967
2015	456,843.40	91,140	99,124	357,720	30.09	11,888
2016	686,235.11	119,542	130,014	556,221	30.81	18,053
2017	746,686.36	110,883	120,596	626,090	31.54	19,851
2018	883,554.65	108,147	117,621	765,934	32.26	23,743
2019	540,777.32	51,861	56,404	484,373	33.00	14,678
2020	217,191.83	14,943	16,252	200,940	33.86	5,934
2021	274,635.67	11,370	12,366	262,270	34.73	7,552
2022	249,999.83	3,450	3,752	246,248	35.60	6,917
	13,382,438.46	5,107,532	5,549,554	7,832,884		297,675
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1959	245.76	201	246			
1960	2,151.30	1,748	2,151			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1961	75,690.37	60,931	75,690			
1962	16,927.20	13,501	16,927			
1963	22,943.49	18,130	22,943			
1964	28,400.21	22,226	28,400			
1965	29,395.47	22,781	29,395			
1966	36,408.56	27,932	36,302	107	10.71	10
1967	32,174.73	24,432	31,753	422	11.07	38
1968	26,931.71	20,234	26,297	635	11.44	56
1969	37,722.84	28,038	36,439	1,283	11.81	109
1970	19,650.04	14,443	18,771	879	12.19	72
1971	9,667.21	7,026	9,131	536	12.57	43
1972	13,313.98	9,563	12,429	885	12.96	68
1973	38,836.17	27,565	35,825	3,011	13.35	226
1974	144,406.45	101,242	131,579	12,828	13.75	933
1975	99,258.76	68,726	89,319	9,939	14.15	702
1976	162,178.02	110,845	144,059	18,119	14.56	1,244
1977	227,638.93	153,508	199,506	28,133	14.98	1,878
1978	126,268.54	83,996	109,165	17,104	15.40	1,111
1979	78,656.93	51,589	67,047	11,610	15.83	733
1980	57,030.55	36,859	47,904	9,127	16.27	561
1981	109,907.92	69,983	90,953	18,955	16.71	1,134
1985	24,654.43	17,288	22,468	2,186	15.98	137
1986	27,447.15	18,933	24,606	2,841	16.41	173
1988	68,000.86	45,275	58,841	9,159	17.32	529
1989	58,448.77	38,377	49,876	8,572	17.52	489
1990	51,140.66	32,909	42,770	8,371	18.01	465
1991	39,011.61	24,702	32,104	6,908	18.25	379
1992	35,854.73	22,201	28,853	7,001	18.76	373
1993	51,676.44	31,404	40,814	10,862	19.04	570
1994	71,235.62	42,228	54,881	16,354	19.58	835
1995	49,500.84	28,720	37,326	12,175	19.90	612
1996	45,909.70	25,911	33,675	12,235	20.45	598
1997	34,534.58	19,022	24,722	9,813	20.80	472
1998	49,970.37	26,814	34,849	15,122	21.16	715
1999	46,832.83	24,433	31,754	15,079	21.55	700
2000	39,699.21	20,008	26,003	13,696	22.14	619
2001	45,124.99	22,021	28,619	16,506	22.56	732
2002	66,517.98	31,363	40,761	25,757	22.98	1,121
2003	78,667.19	35,746	46,457	32,210	23.42	1,375
2004	165,793.01	72,385	94,075	71,718	23.87	3,005
2005	119,365.27	49,919	64,877	54,488	24.34	2,239
2006	70,424.87	28,001	36,391	34,034	25.00	1,361

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2007	93,502.87	35,363	45,959	47,544	25.48	1,866
2008	109,845.80	39,347	51,137	58,709	25.98	2,260
2009	119,208.92	40,233	52,289	66,920	26.50	2,525
2010	90,572.74	28,639	37,221	53,352	27.03	1,974
2011	78,430.71	23,090	30,009	48,422	27.56	1,757
2012	113,394.32	30,719	39,924	73,471	28.26	2,600
2013	103,879.46	25,762	33,481	70,398	28.81	2,444
2014	114,396.21	25,579	33,244	81,153	29.52	2,749
2015	113,875.06	22,718	29,525	84,350	30.09	2,803
2016	95,701.05	16,671	21,666	74,035	30.81	2,403
2017	26,020.32	3,864	5,022	20,998	31.54	666
2018	56,220.18	6,881	8,943	47,277	32.26	1,465
2019	45,274.31	4,342	5,643	39,631	33.00	1,201
2020	1,226.17	84	109	1,117	33.86	33
2021	447.76	19	25	423	34.73	12
	3,797,612.13	1,936,470	2,511,154	1,286,458		53,175
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1965	1,895.12	1,469	1,690	206	10.35	20
1966	4,989.88	3,828	4,403	587	10.71	55
1967	7,905.20	6,003	6,904	1,001	11.07	90
1968	7,544.59	5,668	6,519	1,026	11.44	90
1969	7,037.34	5,231	6,016	1,021	11.81	86
1970	6,684.62	4,913	5,651	1,034	12.19	85
1971	4,822.66	3,505	4,031	791	12.57	63
1972	5,439.90	3,907	4,494	946	12.96	73
1973	14,933.80	10,600	12,191	2,742	13.35	205
1974	7,861.73	5,512	6,340	1,522	13.75	111
1975	9,613.04	6,656	7,655	1,958	14.15	138
1976	4,932.44	3,371	3,877	1,055	14.56	72
1977	4,347.30	2,932	3,372	975	14.98	65
1978	3,525.43	2,345	2,697	828	15.40	54
1979	2,829.16	1,856	2,135	695	15.83	44
1980	3,571.30	2,308	2,655	917	16.27	56
1981	10,155.76	6,467	7,438	2,718	16.71	163
1982	8,768.97	6,393	7,353	1,416	15.06	94
1983	7,863.13	5,653	6,502	1,361	15.45	88

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

CPG
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1984	27,433.37	19,434	22,352	5,082	15.85	321
1985	14,612.72	10,246	11,784	2,828	15.98	177
1986	17,814.51	12,288	14,133	3,682	16.41	224
1987	8,715.77	5,909	6,796	1,920	16.86	114
1988	6,897.76	4,593	5,283	1,615	17.32	93
1989	18,499.00	12,146	13,970	4,529	17.52	259
1990	17,820.76	11,468	13,190	4,631	18.01	257
1991	13,760.77	8,713	10,021	3,740	18.25	205
1992	16,073.60	9,953	11,447	4,626	18.76	247
1993	6,559.93	3,986	4,584	1,976	19.04	104
1994	29,217.11	17,320	19,920	9,297	19.58	475
1995	25,165.33	14,601	16,793	8,372	19.90	421
1996	58,774.81	33,173	38,153	20,621	20.45	1,008
1997	115,510.48	63,623	73,175	42,336	20.80	2,035
1998	69,851.40	37,482	43,109	26,742	21.16	1,264
1999	54,506.47	28,436	32,705	21,801	21.55	1,012
2000	47,330.67	23,855	27,436	19,894	22.14	899
2001	65,564.04	31,995	36,798	28,766	22.56	1,275
2002	94,751.21	44,675	51,382	43,369	22.98	1,887
2003	27,748.85	12,609	14,502	13,247	23.42	566
2004	181,730.07	79,343	91,255	90,475	23.87	3,790
2005	3,879.80	1,623	1,867	2,013	24.34	83
2006	111,923.85	44,501	51,182	60,742	25.00	2,430
2007	9,306.75	3,520	4,048	5,258	25.48	206
2008	78,534.49	28,131	32,354	46,180	25.98	1,778
2009	77,935.00	26,303	30,252	47,683	26.50	1,799
2010	77,881.91	24,626	28,323	49,559	27.03	1,833
2011	36,000.84	10,599	12,190	23,811	27.56	864
2012	9,612.23	2,604	2,995	6,617	28.26	234
2013	1,472.30	365	420	1,053	28.81	37
2014	2,742.40	613	705	2,037	29.52	69
2015	4,238.77	846	973	3,266	30.09	109
2016	13,257.55	2,309	2,656	10,602	30.81	344
2017	6,407.77	952	1,095	5,313	31.54	168
2018	19,731.53	2,415	2,778	16,954	32.26	526

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2019	1,948.17	187	215	1,733	33.00	53
2020	29,120.23	2,003	2,304	26,817	33.86	792
2021	20,518.00	849	976	19,542	34.73	563
	1,547,571.59	726,911	836,044	711,528		30,173
	18,727,622.18	7,770,913	8,896,752	9,830,870		381,023

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.8 2.03

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1953	691.53	632	692			
1956	2,239.85	2,005	2,240			
1957	4,785.87	4,253	4,786			
1960	16,750.58	14,554	16,751			
1961	12,800.59	11,037	12,738	63	6.20	10
1962	22,033.72	18,846	21,750	284	6.51	44
1963	24,186.10	20,520	23,682	504	6.82	74
1964	21,937.83	18,457	21,301	637	7.14	89
1965	14,345.92	11,964	13,808	538	7.47	72
1966	22,819.15	18,859	21,765	1,054	7.81	135
1967	33,625.63	27,536	31,779	1,847	8.15	227
1968	78,227.64	63,451	73,228	4,999	8.50	588
1969	79,698.42	63,989	73,849	5,849	8.87	659
1970	56,628.40	45,001	51,935	4,693	9.24	508
1971	50,484.00	39,680	45,794	4,690	9.63	487
1972	74,487.40	57,885	66,805	7,683	10.03	766
1973	5,856.45	4,498	5,191	665	10.44	64
1974	2,435.60	1,848	2,133	303	10.86	28
1975	3,447.78	2,582	2,980	468	11.30	41
1976	1,925.80	1,423	1,642	284	11.75	24
1979	129,595.68	91,638	105,759	23,837	13.18	1,809
1980	273,942.52	190,664	220,044	53,899	13.68	3,940
1981	280,781.60	192,243	221,866	58,915	14.19	4,152
1982	232,089.47	174,833	201,774	30,316	13.26	2,286
1983	89,210.82	66,248	76,456	12,754	13.69	932
1984	47,248.78	34,562	39,888	7,361	14.13	521
1985	101,055.89	72,760	83,972	17,084	14.58	1,172
1986	78,585.49	55,646	64,221	14,365	15.05	954
1987	157,570.97	109,638	126,532	31,039	15.52	2,000
1988	283,620.35	193,741	223,595	60,025	16.01	3,749
1989	183,420.00	122,891	141,828	41,592	16.50	2,521
1990	203,975.86	133,910	154,545	49,431	17.00	2,908
1991	221,578.38	142,386	164,327	57,252	17.52	3,268
1992	121,714.83	76,473	88,257	33,458	18.04	1,855
1993	67,829.07	41,620	48,033	19,796	18.58	1,065
1994	215,739.93	129,120	149,017	66,723	19.12	3,490
1995	283,678.95	165,385	190,870	92,809	19.67	4,718
1996	638,322.65	361,993	417,774	220,549	20.23	10,902
1997	114,991.22	63,337	73,097	41,894	20.80	2,014
1998	89,135.98	47,608	54,944	34,192	21.37	1,600
1999	211,901.85	109,553	126,434	85,467	21.95	3,894
2000	61,111.51	30,525	35,229	25,883	22.55	1,148

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2001	5,688.76	2,752	3,176	2,513	22.94	110
2002	124,248.21	57,825	66,735	57,513	23.55	2,442
2005	16,976.59	6,952	8,023	8,953	25.24	355
2007	36,240.36	13,423	15,491	20,749	26.34	788
2008	123,273.33	43,072	49,709	73,564	27.00	2,725
2012	13,100.09	3,479	4,015	9,085	29.03	313
2014	217,660.91	48,103	55,515	162,146	29.96	5,412
2015	137,276.88	27,071	31,242	106,034	30.52	3,474
2016	122,361.10	21,242	24,515	97,846	30.95	3,161
2017	414,834.73	62,059	71,622	343,213	31.26	10,979
2018	224,701.21	27,998	32,312	192,389	31.60	6,088
2019	903,092.59	89,406	103,183	799,910	31.84	25,123
2020	3,023,610.46	220,724	254,736	2,768,874	31.75	87,209
2021	1,049,172.82	47,842	55,214	993,959	31.39	31,665
	11,028,748.10	3,707,742	4,278,799	6,749,949		244,558
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1954	860.15	781	860			
1956	7,054.30	6,314	7,054			
1957	11,192.51	9,946	11,193			
1958	5,050.93	4,456	5,051			
1959	689.61	604	690			
1960	32,725.24	28,435	32,725			
1961	10,605.59	9,144	10,606			
1962	22,867.17	19,559	22,867			
1963	60,787.04	51,574	60,787			
1964	79,108.77	66,557	79,109			
1965	131,939.84	110,038	131,940			
1966	124,040.09	102,512	123,428	612	7.81	78
1967	208,085.37	170,399	205,167	2,918	8.15	358
1968	233,579.88	189,459	228,116	5,464	8.50	643
1969	194,219.76	155,937	187,754	6,465	8.87	729
1970	271,294.84	215,590	259,579	11,716	9.24	1,268
1971	229,764.59	180,595	217,443	12,321	9.63	1,279
1972	257,964.38	200,467	241,370	16,594	10.03	1,654
1973	109,357.30	83,986	101,122	8,235	10.44	789
1974	90,753.81	68,852	82,901	7,853	10.86	723

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1975	52,979.89	39,676	47,771	5,208	11.30	461
1976	53,093.99	39,231	47,236	5,858	11.75	499
1977	29,803.40	21,717	26,148	3,655	12.21	299
1978	50,738.04	36,430	43,863	6,875	12.69	542
1979	92,133.69	65,149	78,442	13,692	13.18	1,039
1980	491,009.86	341,743	411,472	79,538	13.68	5,814
1981	230,826.16	158,040	190,286	40,540	14.19	2,857
1982	80,975.76	60,999	73,445	7,531	13.26	568
1983	42,059.45	31,233	37,606	4,454	13.69	325
1984	46,511.61	34,023	40,965	5,547	14.13	393
1985	72,222.02	52,000	62,610	9,612	14.58	659
1986	43,855.97	31,054	37,390	6,466	15.05	430
1987	107,897.65	75,075	90,393	17,504	15.52	1,128
1988	160,625.82	109,723	132,111	28,515	16.01	1,781
1989	30,425.01	20,385	24,544	5,881	16.50	356
1990	108,749.56	71,394	85,961	22,788	17.00	1,340
1991	127,229.75	81,758	98,440	28,790	17.52	1,643
1992	44,347.42	27,863	33,548	10,799	18.04	599
1993	29,918.28	18,358	22,104	7,815	18.58	421
1994	29,674.28	17,760	21,384	8,291	19.12	434
1995	34,913.41	20,355	24,508	10,405	19.67	529
1996	42,589.04	24,152	29,080	13,509	20.23	668
1997	147,679.42	81,342	97,939	49,740	20.80	2,391
1998	59,434.64	31,744	38,221	21,214	21.37	993
1999	107,844.18	55,755	67,131	40,713	21.95	1,855
2000	88,357.27	44,134	53,139	35,218	22.55	1,562
2001	82,991.73	40,151	48,343	34,648	22.94	1,510
2002	24,753.36	11,520	13,871	10,883	23.55	462
2003	6,572.47	2,935	3,534	3,039	24.17	126
2004	11,171.29	4,795	5,773	5,398	24.60	219
2005	8,155.02	3,339	4,020	4,135	25.24	164
2006	8,567.60	3,336	4,017	4,551	25.87	176
2007	26,075.02	9,658	11,629	14,446	26.34	548
2008	31,803.84	11,112	13,379	18,425	27.00	682
2009	68,220.04	22,472	27,057	41,163	27.48	1,498
2010	60,218.85	18,596	22,390	37,829	27.98	1,352
2011	489,447.99	140,716	169,428	320,020	28.50	11,229
2012	154,849.37	41,128	49,520	105,330	29.03	3,628
2013	5,908.18	1,437	1,730	4,178	29.56	141
2014	69,835.34	15,434	18,583	51,252	29.96	1,711

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2015	3,012,389.09	594,043	715,251	2,297,138	30.52	75,267
2016	2,481,717.48	430,826	518,731	1,962,986	30.95	63,424
2017	56,121.74	8,396	10,109	46,013	31.26	1,472
	11,086,635.15	4,626,192	5,562,867	5,523,768		200,716
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1940	90.00	89	90			
1942	90.00	88	90			
1943	132.66	130	133			
1944	519.95	505	520			
1945	66.33	64	66			
1946	197.92	190	198			
1947	210.99	201	211			
1948	189.93	180	190			
1949	87.26	82	87			
1950	87.44	82	87			
1951	87.28	81	87			
1953	1,265.02	1,157	1,262	3	3.85	1
1955	1,296.62	1,169	1,275	21	4.43	5
1956	1,460.37	1,307	1,426	35	4.72	7
1957	7,995.25	7,105	7,750	245	5.01	49
1958	2,885.06	2,545	2,776	109	5.30	21
1959	2,623.82	2,297	2,506	118	5.60	21
1960	13,164.96	11,439	12,478	687	5.90	116
1961	21,807.35	18,803	20,511	1,296	6.20	209
1962	5,144.51	4,400	4,800	345	6.51	53
1963	11,141.18	9,453	10,312	830	6.82	122
1964	27,223.97	22,904	24,984	2,240	7.14	314
1965	25,450.83	21,226	23,154	2,297	7.47	307
1966	44,735.37	36,971	40,329	4,406	7.81	564
1967	40,165.22	32,891	35,879	4,287	8.15	526
1968	46,527.03	37,739	41,167	5,360	8.50	631
1969	40,719.90	32,694	35,664	5,056	8.87	570
1970	46,369.74	36,849	40,196	6,174	9.24	668
1971	37,753.88	29,675	32,370	5,383	9.63	559
1972	16,346.27	12,703	13,857	2,489	10.03	248
1973	17,281.90	13,272	14,478	2,804	10.44	269

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1974	15,500.00	11,759	12,827	2,673	10.86	246
1975	23,356.27	17,491	19,080	4,277	11.30	378
1976	7,679.24	5,674	6,189	1,490	11.75	127
1977	8,292.18	6,042	6,591	1,701	12.21	139
1978	4,682.18	3,362	3,667	1,015	12.69	80
1979	8,792.04	6,217	6,782	2,010	13.18	153
1980	17,159.04	11,943	13,028	4,131	13.68	302
1981	98,862.58	67,688	73,836	25,026	14.19	1,764
1982	107,317.69	80,842	88,185	19,133	13.26	1,443
1983	82,054.88	60,934	66,469	15,586	13.69	1,138
1984	56,055.83	41,005	44,730	11,326	14.13	802
1985	108,966.47	78,456	85,582	23,384	14.58	1,604
1986	78,897.92	55,868	60,943	17,955	15.05	1,193
1987	101,101.12	70,346	76,736	24,366	15.52	1,570
1988	89,032.58	60,818	66,342	22,690	16.01	1,417
1989	201,578.11	135,057	147,324	54,254	16.50	3,288
1990	181,749.75	119,319	130,157	51,593	17.00	3,035
1991	168,687.80	108,399	118,245	50,443	17.52	2,879
1992	259,022.46	162,744	177,526	81,496	18.04	4,518
1993	307,081.30	188,425	205,540	101,541	18.58	5,465
1994	257,960.73	154,389	168,412	89,548	19.12	4,683
1995	299,469.26	174,591	190,449	109,020	19.67	5,542
1996	383,632.67	217,558	237,319	146,314	20.23	7,233
1997	265,781.91	146,393	159,690	106,092	20.80	5,101
1998	699,360.80	373,529	407,457	291,904	21.37	13,660
1999	743,037.99	384,151	419,044	323,994	21.95	14,761
2000	582,884.63	291,151	317,597	265,288	22.55	11,764
2001	498,094.90	240,978	262,866	235,229	22.94	10,254
2002	223,078.26	103,821	113,251	109,827	23.55	4,664
2003	700,236.52	312,726	341,131	359,105	24.17	14,857
2004	1,411,277.60	605,720	660,738	750,539	24.60	30,510
2005	492,523.31	201,688	220,008	272,516	25.24	10,797
2006	776,322.51	302,300	329,758	446,564	25.87	17,262
2007	643,709.12	238,430	260,087	383,622	26.34	14,564
2008	820,138.66	286,556	312,584	507,554	27.00	18,798
2009	486,920.76	160,392	174,961	311,960	27.48	11,352
2010	543,937.56	167,968	183,225	360,713	27.98	12,892
2011	987,719.26	283,969	309,762	677,957	28.50	23,788
2012	353,222.86	93,816	102,337	250,885	29.03	8,642
2013	398,558.63	96,929	105,733	292,825	29.56	9,906
2014	361,466.55	79,884	87,140	274,327	29.96	9,156
2015	393,127.17	77,525	84,567	308,560	30.52	10,110

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2016	446,979.04	77,596	84,644	362,335	30.95	11,707
2017	844,671.07	126,363	137,841	706,830	31.26	22,611
2018	1,108,263.63	138,090	150,633	957,631	31.60	30,305
2019	573,973.60	56,823	61,984	511,989	31.84	16,080
2020	121,553.14	8,873	9,679	111,874	31.75	3,524
2021	35,273.65	1,608	1,754	33,520	31.39	1,068
	17,792,163.24	7,034,497	7,673,362	10,118,801		392,392
	39,907,546.49	15,368,431	17,515,028	22,392,518		837,666

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.7 2.10

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.0 OTHER PROPERTY ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1966	1,968.69	1,510	3,804-	5,772	10.71	539
1967	207.34	157	395-	603	11.07	54
1968	820.82	617	1,554-	2,375	11.44	208
1969	4,348.68	3,232	8,142-	12,490	11.81	1,058
1970	585.40	430	1,083-	1,669	12.19	137
1971	1,925.29	1,399	3,524-	5,449	12.57	433
1972	16,780.77	12,053	30,362-	47,143	12.96	3,638
2004	19,260.94	8,409	21,183-	40,444	23.87	1,694
2005	22,925.98	9,588	24,153-	47,079	24.34	1,934
	68,823.91	37,395	94,200-	163,024		9,695

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.8 14.09

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1929	141.00	141	141			
1955	2,275.45	2,051	2,275			
1956	989.22	885	989			
1957	545.83	485	546			
1958	236.59	209	237			
1959	739.15	647	739			
1960	6,231.82	5,415	6,194	38	5.90	6
1961	5,465.73	4,713	5,391	75	6.20	12
1962	1,776.66	1,520	1,739	38	6.51	6
1963	1,519.13	1,289	1,474	45	6.82	7
1964	1,895.48	1,595	1,824	71	7.14	10
1965	611.14	510	583	28	7.47	4
1966	1,500.19	1,240	1,418	82	7.81	10
1967	7,810.50	6,396	7,316	494	8.15	61
1968	5,156.86	4,183	4,785	372	8.50	44
1969	2,743.23	2,203	2,520	223	8.87	25
1970	1,104.82	878	1,004	100	9.24	11
1971	31,924.90	25,093	28,704	3,221	9.63	334
1972	2,029.09	1,577	1,804	225	10.03	22
1973	5,741.28	4,409	5,043	698	10.44	67
1974	677.56	514	588	90	10.86	8
1975	501.75	376	430	72	11.30	6
1976	3,733.18	2,758	3,155	578	11.75	49
1977	1,421.54	1,036	1,185	236	12.21	19
1978	182.88	131	150	33	12.69	3
1979	5,235.99	3,702	4,235	1,001	13.18	76
1980	17,091.10	11,895	13,607	3,485	13.68	255
1981	121,509.06	83,194	95,164	26,345	14.19	1,857
1982	95,200.74	71,715	82,034	13,167	13.26	993
1983	6,768.10	5,026	5,749	1,019	13.69	74
1984	6,649.28	4,864	5,564	1,085	14.13	77
1985	25,257.56	18,185	20,802	4,456	14.58	306
1986	23,743.92	16,813	19,232	4,512	15.05	300
1987	25,830.88	17,973	20,559	5,272	15.52	340
1988	26,270.40	17,945	20,527	5,743	16.01	359
1989	52,802.47	35,378	40,468	12,334	16.50	748
1990	55,497.04	36,434	41,676	13,821	17.00	813
1991	30,826.21	19,809	22,659	8,167	17.52	466
1992	56,752.96	35,658	40,789	15,964	18.04	885
1993	45,455.69	27,892	31,905	13,550	18.58	729
1994	30,338.27	18,157	20,770	9,569	19.12	500
1995	22,678.63	13,222	15,124	7,554	19.67	384

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1996	22,335.06	12,666	14,488	7,847	20.23	388
1997	8,544.26	4,706	5,383	3,161	20.80	152
1998	8,784.27	4,692	5,367	3,417	21.37	160
1999	13,041.26	6,742	7,712	5,329	21.95	243
2000	2,551.99	1,275	1,458	1,094	22.55	49
2004	347.18	149	170	177	24.60	7
2005	3,317.00	1,358	1,553	1,764	25.24	70
2006	3,670.43	1,429	1,635	2,036	25.87	79
2010	54.74	17	19	35	27.98	1
2012	115,202.00	30,598	35,001	80,201	29.03	2,763
2013	22,348.33	5,435	6,217	16,131	29.56	546
2014	10,178.04	2,249	2,573	7,605	29.96	254
2015	499.19	98	112	387	30.52	13
2017	320.08	48	55	265	31.26	8
2018	5,899.53	735	841	5,059	31.60	160
2019	1,261.22	125	143	1,118	31.84	35
	953,217.86	580,438	663,828	289,390		14,794

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.6 1.55

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. 0						
1989	290.57	274	291			
1990	10,556.06	9,847	10,556			
1991	4,510.10	4,177	4,510			
1992	3,050.56	2,791	3,051			
1993	5,858.48	5,305	5,858			
1994	335.37	299	335			
1997	104.02	89	104			
	24,705.16	22,782	24,705			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1919	265.57	266	266			
1922	142.27	142	142			
1924	8,840.88	8,841	8,841			
1947	455.80	456	456			
1949	22,186.47	22,186	22,186			
1950	8,371.36	8,371	8,371			
1951	1,368.79	1,369	1,369			
1952	1,125.65	1,126	1,126			
1953	30,125.92	30,126	30,126			
1954	5,517.65	5,518	5,518			
1955	601.79	602	602			
1956	8,337.58	8,338	8,338			
1957	1,905.18	1,905	1,905			
1958	651.12	648	651			
1959	15,785.61	15,614	15,786			
1960	2,005.39	1,969	2,005			
1961	1,960.14	1,910	1,960			
1962	288.11	278	288			
1963	1,039.65	997	1,040			
1964	5,769.25	5,486	5,769			
1965	1,751.72	1,652	1,752			
1966	3,912.12	3,662	3,912			
1967	4,863.78	4,521	4,864			
1968	8,062.42	7,440	8,062			
1969	1,581.42	1,449	1,581			
1970	2,285.43	2,080	2,285			
1971	10,974.98	9,921	10,975			
1972	4,046.99	3,633	4,047			
1974	1,652.12	1,461	1,652			
1975	8,480.27	7,446	8,480			
1976	7,949.17	6,923	7,949			
1977	2,458.86	2,124	2,459			
1978	1,265.56	1,084	1,266			
1979	752.79	639	753			
1980	1,718.37	1,444	1,708	10	5.58	2
1981	10,162.67	8,452	10,000	163	5.89	28
1982	12,027.61	10,522	12,028			
1983	1,755.64	1,519	1,756			
1984	30,831.09	26,472	30,831			
1985	13,068.42	11,075	13,068			
1986	19,569.87	16,429	19,454	116	6.98	17
1987	23,586.65	19,511	23,104	483	7.42	65

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1988	13,276.05	10,809	12,799	477	7.87	61
1989	15,968.66	12,785	15,139	830	8.34	100
1990	33,323.13	26,319	31,165	2,158	8.65	249
1991	26,014.16	20,158	23,870	2,144	9.15	234
1992	15,045.39	11,425	13,529	1,517	9.66	157
1993	23,968.53	17,818	21,099	2,870	10.18	282
1994	51,100.60	37,140	43,979	7,122	10.71	665
1995	69,990.02	49,847	59,025	10,965	11.11	987
1996	45,414.72	31,531	37,337	8,078	11.67	692
1997	84,495.34	57,102	67,616	16,879	12.23	1,380
1998	75,399.07	49,507	58,623	16,776	12.81	1,310
1999	119,656.29	76,197	90,227	29,429	13.40	2,196
2000	199,968.82	123,281	145,981	53,988	14.00	3,856
2001	116,038.59	69,113	81,839	34,200	14.60	2,342
2002	42,457.03	24,370	28,857	13,600	15.21	894
2003	222,013.40	122,507	145,064	76,949	15.84	4,858
2004	109,705.10	58,045	68,733	40,972	16.47	2,488
2005	70,405.76	35,611	42,168	28,238	17.10	1,651
2006	85,043.37	40,974	48,518	36,525	17.75	2,058
2007	37,304.93	17,056	20,196	17,108	18.40	930
2008	97,908.80	42,306	50,096	47,813	19.06	2,509
2009	42,499.78	17,327	20,517	21,982	19.61	1,121
2011	14,980.73	5,306	6,283	8,698	20.97	415
2013	30,446.98	9,110	10,787	19,660	22.25	884
2018	12,429.20	1,868	2,212	10,217	25.44	402
2019	31,358.25	3,732	4,419	26,939	25.91	1,040
2020	191,812.76	16,649	19,715	172,098	26.32	6,539
	2,167,527.59	1,253,500	1,458,523	709,005		40,412
PNG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1962	460.81	445	461			
1976	21,500.00	18,723	21,500			
1984	1,544.96	1,327	1,545			
1987	5,496.89	4,547	5,497			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1988	2,425.60	1,975	2,426			
1997	821.60	555	750	72	12.23	6
2008	85,066.24	36,757	49,646	35,420	19.06	1,858
	117,316.10	64,329	81,824	35,492		1,864
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1915	0.25		0			
1920	46.40	46	46			
1921	65.00	65	65			
1925	288.57	289	289			
1927	8.25	8	8			
1928	265.80	266	266			
1929	32.00	32	32			
1930	401.84	402	402			
1931	576.33	576	576			
1932	862.24	862	862			
1933	179.53	180	180			
1936	339.96	340	340			
1937	180.10	180	180			
1938	702.11	702	702			
1939	70.20	70	70			
1940	114.20	114	114			
1942	93.19	93	93			
1947	107.86	108	108			
1948	228.20	228	228			
1951	115.54	116	116			
1952	399.62	400	400			
1954	526.32	526	526			
1955	866.71	867	867			
1956	3,485.13	3,485	3,485			
1957	166.98	167	167			
1958	807.41	804	807			
1959	3,980.48	3,937	3,980			
1960	3,557.12	3,492	3,557			
1961	940.90	917	941			
1962	2,160.12	2,088	2,160			
1963	2,440.64	2,340	2,441			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1964	1,463.53	1,392	1,464			
1965	852.14	804	852			
1966	4,391.44	4,110	4,391			
1967	7,725.03	7,180	7,725			
1968	9,375.01	8,652	9,375			
1969	1,802.13	1,652	1,802			
1970	4,312.49	3,926	4,312			
1971	727.19	657	727			
1972	12,970.95	11,644	12,971			
1973	4,161.73	3,709	4,141	21	3.81	6
1974	5,521.13	4,884	5,452	69	4.04	17
1975	4,072.92	3,576	3,992	81	4.27	19
1976	1,691.94	1,473	1,644	47	4.52	10
1977	2,859.26	2,470	2,757	102	4.77	21
1978	9,079.27	7,774	8,679	400	5.03	80
1979	8,076.46	6,853	7,651	426	5.30	80
1980	16,025.59	13,471	15,039	987	5.58	177
1981	16,463.34	13,693	15,287	1,177	5.89	200
1982	18,913.59	16,546	18,472	442	5.80	76
1983	17,303.36	14,967	16,709	594	6.16	96
1984	24,489.09	21,026	23,473	1,016	6.34	160
1985	30,607.35	25,940	28,959	1,648	6.75	244
1986	47,810.95	40,137	44,808	3,002	6.98	430
1987	41,095.26	33,994	37,951	3,145	7.42	424
1988	31,108.85	25,329	28,277	2,832	7.87	360
1989	67,276.33	53,861	60,130	7,147	8.34	857
1990	73,855.80	58,331	65,120	8,736	8.65	1,010
1991	72,040.64	55,824	62,321	9,719	9.15	1,062
1992	46,648.02	35,425	39,548	7,100	9.66	735
1993	72,629.85	53,993	60,277	12,353	10.18	1,213
1994	50,628.58	36,797	41,080	9,549	10.71	892
1995	79,302.27	56,479	63,053	16,250	11.11	1,463
1996	207,257.72	143,899	160,647	46,611	11.67	3,994
1997	83,557.81	56,468	63,040	20,518	12.23	1,678
1998	20,844.66	13,687	15,280	5,565	12.81	434
1999	283,838.00	180,748	201,785	82,053	13.40	6,123
2000	62,321.83	38,421	42,893	19,429	14.00	1,388
2001	24,248.93	14,443	16,124	8,125	14.60	557
2007	20,518.49	9,381	10,473	10,046	18.40	546
2011	4,783.98	1,694	1,891	2,893	20.97	138
2014	897.06	242	270	627	22.95	27
2016	7,240.43	1,534	1,713	5,528	24.17	229

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
2017	323,394.81	58,696	65,528	257,867	24.80	10,398
2018	165,355.70	24,853	27,746	137,610	25.44	5,409
2019	186,196.01	22,157	24,736	161,460	25.91	6,232
2020	386,652.62	33,561	37,467	349,185	26.32	13,267
	2,586,398.54	1,250,053	1,392,041	1,194,358		60,052
	4,871,242.23	2,567,882	2,932,388	1,938,855		102,328

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.9   2.10

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387.1 OTHER EQUIPMENT - GRAPHIC DATA BASE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1980	53,900.00	53,900	53,900			
1981	184,018.30	184,018	184,018			
1982	328,563.00	328,563	328,563			
1983	92,573.18	92,573	92,573			
1984	103,914.03	103,914	103,914			
1985	109,975.52	109,976	109,976			
1986	113,888.51	113,889	113,889			
1987	112,021.79	112,022	112,022			
1988	167,324.21	167,324	167,324			
1989	77,363.35	77,363	77,363			
1990	11,534.69	11,535	11,535			
1991	1,588.30	1,588	1,588			
1992	3,540.35	3,540	3,540			
1993	514.88	515	515			
1995	4,074.64	4,075	4,075			
1998	10,727.14	10,513	10,727			
2001	13,978.74	12,022	12,305	1,674	3.50	478
2002	7,564.41	6,203	6,349	1,216	4.50	270
2003	93,599.07	73,007	74,723	18,876	5.50	3,432
	1,490,664.11	1,466,540	1,468,898	21,766		4,180

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2   0.28

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2026 NET SALVAGE PERCENT.. 0						
1943	69.54	66	70			
1944	164.84	156	165			
1945	176.36	167	176			
1949	386.14	364	386			
1950	40,873.99	38,562	40,874			
1951	13,252.51	12,494	13,253			
1952	16,983.70	16,002	16,975	9	3.64	2
1953	18,629.86	17,543	18,609	21	3.64	6
1954	256,090.83	240,964	255,610	480	3.65	132
1955	994.21	935	992	2	3.65	1
1956	872.25	820	870	2	3.65	1
1957	3,418.80	3,210	3,405	14	3.66	4
1958	1,752.94	1,645	1,745	8	3.66	2
1959	2,367.22	2,219	2,354	13	3.66	4
1960	5,153.22	4,828	5,121	32	3.66	9
1961	16,233.87	15,193	16,116	117	3.67	32
1962	11,675.82	10,918	11,582	94	3.67	26
1963	8,198.36	7,660	8,126	73	3.67	20
1964	10,451.97	9,756	10,349	103	3.67	28
1965	5,400.10	5,035	5,341	59	3.68	16
1966	328.72	306	325	4	3.68	1
1967	457.99	426	452	6	3.68	2
1968	1,682.04	1,564	1,659	23	3.68	6
1969	7,075.10	6,570	6,969	106	3.68	29
1970	2,820.16	2,615	2,774	46	3.69	12
1971	1,382.61	1,281	1,359	24	3.69	7
1972	560.39	518	549	11	3.69	3
1973	3,019.97	2,790	2,960	60	3.69	16
1978	1,633.18	1,497	1,588	45	3.70	12
1980	5,978.37	5,462	5,794	184	3.70	50
1983	14,819.56	13,521	14,343	477	3.79	126
1985	12,261.35	11,173	11,852	409	3.65	112
1988	51,464.44	46,519	49,347	2,118	3.67	577
1989	8,229.99	7,417	7,868	362	3.67	99
1990	120,834.68	108,389	114,977	5,857	3.73	1,570
1992	46,925.49	41,792	44,332	2,593	3.75	691
1994	1,695,729.02	1,498,177	1,589,241	106,488	3.76	28,321
1995	21,812.60	19,195	20,362	1,451	3.75	387
1996	2,224.98	1,952	2,071	154	3.71	42
1998	25,445.64	22,069	23,410	2,035	3.75	543
2000	8,225.47	7,051	7,480	746	3.75	199

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2026						
NET SALVAGE PERCENT.. 0						
2001	23,811.12	20,325	21,560	2,251	3.69	610
2002	46,435.27	39,312	41,701	4,734	3.71	1,276
2003	135,221.80	113,640	120,547	14,674	3.70	3,966
2004	72,257.46	60,154	63,810	8,447	3.72	2,271
2005	59,428.42	48,981	51,958	7,470	3.73	2,003
2012	73,812.77	54,489	57,801	16,012	3.72	4,304
2014	122,625.56	85,262	90,444	32,181	3.72	8,651
2015	9,324.53	6,231	6,610	2,715	3.72	730
2016	80,066.49	50,898	53,992	26,075	3.72	7,009
2018	20,521.49	11,229	11,912	8,610	3.72	2,315
2020	28,841.28	11,594	12,299	16,543	3.72	4,447
2022	1,971,734.58	235,425	249,735	1,722,000	3.69	466,667
	5,090,139.05	2,926,361	3,104,199	1,985,940		537,337
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2030						
NET SALVAGE PERCENT.. 0						
1951	812.25	723	767	45	7.26	6
1953	24,649.85	21,878	23,208	1,442	7.28	198
1954	20,254.18	17,950	19,041	1,213	7.30	166
1955	795,050.41	703,651	746,413	48,638	7.31	6,654
1956	1,037.71	917	973	65	7.32	9
1957	10,157.06	8,962	9,507	650	7.34	89
1958	2,460.78	2,168	2,300	161	7.35	22
1959	5,581.91	4,910	5,208	374	7.36	51
1960	4,906.80	4,309	4,571	336	7.37	46
1961	535,025.24	469,094	497,601	37,424	7.38	5,071
1962	336.35	294	312	24	7.39	3
1963	275.79	241	256	20	7.40	3
1966	3,832.40	3,329	3,531	301	7.43	41
1967	2,771.56	2,402	2,548	224	7.44	30
1969	860.89	743	788	73	7.46	10
1970	8,627.36	7,428	7,879	748	7.47	100
1971	17,110.98	14,696	15,589	1,522	7.48	203
1972	3,367.69	2,885	3,060	307	7.49	41
1973	2,844.13	2,431	2,579	265	7.49	35
1974	1,205,909.69	1,027,700	1,090,154	115,755	7.50	15,434

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2030						
NET SALVAGE PERCENT.. 0						
1975	22,623.29	19,225	20,393	2,230	7.51	297
1976	53,241.56	45,109	47,850	5,391	7.52	717
1977	35,037.92	29,600	31,399	3,639	7.52	484
1978	16,010.96	13,482	14,301	1,710	7.53	227
1979	148,434.31	124,593	132,165	16,270	7.53	2,161
1980	466,465.33	390,156	413,866	52,599	7.54	6,976
1981	57,134.63	47,608	50,501	6,633	7.55	879
1982	38,416.35	32,362	34,329	4,088	7.58	539
1983	2,901.32	2,441	2,589	312	7.45	42
1984	89,345.02	74,639	79,175	10,170	7.59	1,340
1985	57,489.36	47,860	50,769	6,721	7.55	890
1986	139,476.56	115,570	122,593	16,883	7.55	2,236
1987	3,316.29	2,731	2,897	419	7.60	55
1988	2,083.71	1,711	1,815	269	7.52	36
1989	968,686.59	791,804	839,923	128,764	7.48	17,214
1990	708,723.67	575,838	610,832	97,891	7.50	13,052
1991	57,129.57	46,069	48,869	8,261	7.56	1,093
1992	351,366.89	281,867	298,996	52,371	7.52	6,964
1993	36,878.43	29,374	31,159	5,719	7.54	758
1994	355,811.77	280,878	297,947	57,865	7.60	7,614
1995	57,829.15	45,326	48,081	9,749	7.59	1,284
1996	43,206.21	33,545	35,584	7,623	7.63	999
1997	18,110.95	13,947	14,795	3,316	7.61	436
1998	266,163.28	203,455	215,819	50,344	7.55	6,668
1999	63,212.26	47,833	50,740	12,472	7.56	1,650
2000	1,488,931.32	1,112,232	1,179,823	309,108	7.62	40,565
2001	471,214.91	348,511	369,690	101,525	7.57	13,411
2002	173,161.24	126,373	134,053	39,108	7.59	5,153
2003	216,653.04	155,904	165,378	51,275	7.60	6,747
2004	252,346.50	178,813	189,680	62,667	7.61	8,235
2005	755,420.55	526,150	558,125	197,296	7.63	25,858
2006	211,175.23	144,613	153,401	57,774	7.60	7,602
2007	819,351.71	549,949	583,370	235,982	7.59	31,091
2008	546,316.32	358,056	379,815	166,501	7.62	21,851
2009	131,971.97	84,449	89,581	42,391	7.60	5,578
2010	91,996.25	57,148	60,621	31,375	7.62	4,117
2011	74,902.45	45,046	47,783	27,119	7.62	3,559
2012	248,880.14	144,251	153,017	95,863	7.62	12,580
2013	35,910.92	19,923	21,134	14,777	7.62	1,939
2014	443,217.75	233,576	247,771	195,447	7.63	25,616
2015	382,055.87	189,423	200,934	181,121	7.63	23,738

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2030						
NET SALVAGE PERCENT.. 0						
2016	807,444.71	371,586	394,168	413,277	7.62	54,236
2017	192,667.73	80,843	85,756	106,912	7.61	14,049
2018	1,024,715.14	380,887	404,034	620,681	7.61	81,561
2019	2,659,277.28	838,736	889,707	1,769,570	7.60	232,838
2020	67,292.34	16,689	17,703	49,589	7.58	6,542
2021	362,985.93	60,183	63,840	299,146	7.55	39,622
2022	657,811.89	41,442	43,960	613,851	7.43	82,618
	18,820,669.60	11,658,517	12,367,017	6,453,653		851,929
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2050						
NET SALVAGE PERCENT.. 0						
1951	729.51	525	557	173	20.87	8
1957	163.70	114	121	43	21.80	2
1962	40,943.45	27,815	29,505	11,438	22.50	508
1965	1,565,830.07	1,044,722	1,108,211	457,619	22.89	19,992
1966	142,841.12	94,718	100,474	42,367	23.01	1,841
1967	15,942.62	10,505	11,143	4,799	23.13	207
1968	9,453.29	6,187	6,563	2,890	23.25	124
1969	18,652.79	12,128	12,865	5,788	23.36	248
1970	12,893.85	8,326	8,832	4,062	23.47	173
1971	7,216.33	4,627	4,908	2,308	23.58	98
1975	431.80	269	285	146	23.99	6
1976	3,656.17	2,255	2,392	1,264	24.09	52
1977	2,768.51	1,693	1,796	973	24.18	40
1981	872.88	514	545	328	24.53	13
1982	6,154.88	3,889	4,125	2,030	23.60	86
1984	25,980.93	16,004	16,977	9,004	24.00	375
1987	84,550.58	50,426	53,490	31,060	24.02	1,293
1989	25,940.84	15,035	15,949	9,992	24.30	411
1990	146,852.54	84,000	89,105	57,748	24.32	2,375
1991	1,838.42	1,037	1,100	738	24.37	30
1992	58,530.60	32,490	34,464	24,066	24.45	984
1994	10,543.25	5,679	6,024	4,519	24.41	185
1996	316,093.92	164,179	174,156	141,938	24.52	5,789
1997	208,936.53	106,014	112,457	96,480	24.75	3,898
1998	101,324.14	50,399	53,462	47,862	24.76	1,933

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2050						
NET SALVAGE PERCENT.. 0						
1999	77,628.16	37,758	40,053	37,576	24.81	1,515
2000	1,472.48	699	741	731	24.89	29
2001	99,727.86	46,314	49,129	50,599	24.80	2,040
2002	62,585.00	28,351	30,074	32,511	24.75	1,314
2003	67,637.53	29,679	31,483	36,155	24.94	1,450
2004	91,592.06	38,972	41,340	50,252	24.98	2,012
2005	181,690.49	75,038	79,598	102,092	24.87	4,105
2006	25,337.36	10,074	10,686	14,651	25.00	586
2007	26,237.83	10,044	10,654	15,583	24.99	624
2008	2,113.48	775	822	1,291	25.03	52
2009	1,659.06	582	617	1,042	24.96	42
2010	11,579.53	3,865	4,100	7,480	24.95	300
2011	102,937.47	32,436	34,407	68,530	25.00	2,741
2012	74,272.89	21,992	23,328	50,944	24.96	2,041
2013	46,309.07	12,800	13,578	32,731	24.87	1,316
2014	313,233.42	79,875	84,729	228,504	24.83	9,203
2015	323,115.59	74,898	79,450	243,666	24.86	9,802
2016	640,428.48	133,209	141,304	499,124	24.75	20,167
2017	530,224.39	96,501	102,365	427,859	24.71	17,315
2018	1,495,111.53	231,443	245,508	1,249,604	24.57	50,859
2019	1,390,228.16	174,196	184,782	1,205,446	24.43	49,343
2020	221,833.88	20,808	22,073	199,761	24.17	8,265
2021	307,095.42	18,303	19,415	287,680	23.69	12,144
2022	53,205.32	1,160	1,230	51,975	22.38	2,322
	8,956,399.18	2,923,322	3,100,975	5,855,424		240,258
UGI-GAS - LEBANON SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2027						
NET SALVAGE PERCENT.. 0						
1992	1,968,949.30	1,705,504	1,809,149	159,800	4.71	33,928
1993	15,226.14	13,116	13,913	1,313	4.75	276
1994	10,056.65	8,627	9,151	905	4.72	192
2000	1,880.00	1,557	1,652	228	4.67	49
2001	34,203.52	28,091	29,798	4,405	4.68	941
2022	7,534.08	732	776	6,758	4.64	1,456
	2,037,849.69	1,757,627	1,864,440	173,410		36,842

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - STONE RIDGE SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2059						
NET SALVAGE PERCENT.. 0						
2009	4,795,848.14	1,431,081	1,518,049	3,277,799	31.75	103,238
2011	174,377.96	46,524	49,351	125,027	31.60	3,957
2020	35,332.08	2,692	2,856	32,476	30.29	1,072
2021	38,715.34	1,874	1,988	36,727	29.46	1,247
2022	20,247.16	362	384	19,863	27.43	724
	5,064,520.68	1,482,533	1,572,628	3,491,893		110,238
UGI-GAS - GAS TRAINING CENTER						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 9-2071						
NET SALVAGE PERCENT.. 0						
2021	27,836,758.65	1,124,605	1,192,948	26,643,811	35.67	746,953
2022	900,000.00	13,590	14,416	885,584	32.61	27,157
	28,736,758.65	1,138,195	1,207,364	27,529,395		774,110
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1871	2,385.33	2,385	2,385			
1905	642.75	643	643			
1910	67.06	67	67			
1911	241.41	241	241			
1915	150.63	151	151			
1922	250.95	251	251			
1923	297.04	297	297			
1924	61.13	61	61			
1928	44,791.52	44,792	44,792			
1929	1,227.11	1,227	1,227			
1931	6,591.16	6,591	6,591			
1932	589.45	589	589			
1933	40.24	40	40			
1934	309.40	309	309			
1935	4,124.32	4,124	4,124			
1937	242.44	242	242			
1938	143.77	144	144			

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ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1940	95.93	96	96			
1943	273.84	274	274			
1947	6,946.66	6,947	6,947			
1948	401.47	401	401			
1949	1,806.43	1,797	1,806			
1950	2,196.55	2,171	2,197			
1951	233.36	229	233			
1953	2,899.07	2,809	2,899			
1955	1,973.05	1,885	1,973			
1957	1,355.54	1,276	1,356			
1958	5,763.15	5,384	5,763			
1959	1,512.13	1,402	1,507	5	2.92	2
1960	3,574.90	3,288	3,534	41	3.21	13
1961	649.28	592	636	13	3.50	4
1962	9,412.34	8,521	9,158	255	3.79	67
1963	12,936.88	11,617	12,485	452	4.08	111
1964	3,052.55	2,719	2,922	130	4.37	30
1966	2,516.15	2,204	2,369	148	4.96	30
1967	1,274.89	1,107	1,190	85	5.26	16
1968	419.83	361	388	32	5.56	6
1970	80.61	68	73	8	6.19	1
1971	1,544.75	1,293	1,390	155	6.51	24
1972	1,090.13	904	972	119	6.84	17
1975	164.27	132	142	22	7.90	3
1976	3,452.10	2,738	2,943	510	8.28	62
1977	7,165.00	5,612	6,031	1,134	8.67	131
1978	6,220.72	4,810	5,169	1,051	9.07	116
1979	3,107.33	2,370	2,547	560	9.49	59
1980	5,058.60	3,804	4,088	970	9.92	98
1983	369.74	294	316	54	10.25	5
1986	5,526.05	4,195	4,508	1,018	11.58	88
1988	338.67	249	268	71	12.45	6
1989	11,535.55	8,308	8,929	2,607	13.01	200
1991	3,137.18	2,174	2,336	801	13.95	57
1994	17,386.12	11,298	12,142	5,244	15.36	341
1995	5,075.97	3,211	3,451	1,625	15.98	102
1997	38,896.24	23,408	25,157	13,740	16.87	814
1998	20,290.00	11,831	12,715	7,575	17.52	432
1999	9,250.00	5,239	5,630	3,620	17.99	201
2000	4,627.46	2,530	2,719	1,908	18.65	102
2001	14,287.96	7,557	8,122	6,166	19.15	322
2002	39,331.76	20,075	21,575	17,757	19.66	903

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES SURVIVOR CURVE.. IOWA 40-R2 NET SALVAGE PERCENT.. 0						
2003	18,220.00	8,953	9,622	8,598	20.18	426
2005	53,233.48	23,944	25,733	27,501	21.41	1,284
2007	2,169.82	884	950	1,220	22.52	54
2011	148,951.37	47,277	50,809	98,143	24.73	3,969
2012	1,935.54	569	612	1,324	25.21	53
2013	5,265.73	1,421	1,527	3,739	25.71	145
2014	34,471.72	8,439	9,069	25,402	26.22	969
2015	20,002.66	4,381	4,708	15,294	26.75	572
2016	52,555.80	10,143	10,901	41,655	27.17	1,533
2017	7,563.46	1,256	1,350	6,214	27.61	225
2018	262,071.27	36,323	39,036	223,035	27.97	7,974
2019	145,916.08	16,138	17,344	128,573	28.15	4,567
2020	106,559.48	8,653	9,299	97,260	28.27	3,440
2021	33,284.92	1,691	1,817	31,468	28.00	1,124
	1,211,587.25	409,406	434,286	777,301		30,698
PNG - EMPIRE YARD - MAJOR STRUCTURES INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 12-2047 NET SALVAGE PERCENT.. 0						
1960	100,501.80	70,592	75,692	24,810	20.85	1,190
1961	86,510.77	60,446	64,813	21,698	20.97	1,035
1962	140,561.75	97,706	104,765	35,797	21.08	1,698
1963	9,442.52	6,528	7,000	2,443	21.19	115
1964	3,674.63	2,527	2,710	965	21.30	45
1965	477.15	326	350	128	21.41	6
1966	296.27	201	216	81	21.51	4
1967	857.18	579	621	236	21.61	11
1968	3,557.29	2,389	2,562	996	21.71	46
1969	658.90	440	472	187	21.81	9
1970	2,316.86	1,536	1,647	670	21.90	31
1971	74,576.52	49,135	52,685	21,892	21.99	996
1972	5,261.51	3,443	3,692	1,570	22.08	71
1973	5,843.81	3,797	4,071	1,772	22.17	80
1974	1,074.01	693	743	331	22.26	15
1975	20,047.39	12,834	13,761	6,286	22.34	281
1976	98,085.49	62,317	66,819	31,266	22.42	1,395
1977	261,701.31	164,977	176,896	84,806	22.49	3,771
1978	14,817.48	9,264	9,933	4,884	22.57	216

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
1979	31,222.64	19,356	20,754	10,468	22.64	462
1980	50,105.39	30,781	33,005	17,101	22.72	753
1981	48,821.12	29,729	31,877	16,944	22.78	744
1982	16,052.09	10,402	11,153	4,899	22.00	223
1983	15,874.45	10,158	10,892	4,983	22.23	224
1984	47,473.08	29,975	32,141	15,333	22.48	682
1985	68,563.33	42,934	46,036	22,528	22.38	1,007
1986	219,783.73	136,376	146,228	73,555	22.32	3,295
1987	95,475.26	58,297	62,509	32,967	22.64	1,456
1988	78,736.60	47,541	50,976	27,761	22.64	1,226
1989	133,492.90	79,602	85,353	48,140	22.68	2,123
1990	1,470.77	865	927	543	22.75	24
1991	12,725.28	7,416	7,952	4,774	22.55	212
1992	108,029.34	61,944	66,419	41,610	22.69	1,834
1993	238,421.42	134,327	144,031	94,390	22.86	4,129
1994	9,207.03	5,117	5,487	3,720	22.78	163
1995	132,805.48	72,671	77,921	54,884	22.75	2,412
1996	77,446.78	41,457	44,452	32,995	23.00	1,435
1997	4,614,536.34	2,424,016	2,599,138	2,015,398	23.04	87,474
1998	280,007.14	144,764	155,222	124,785	22.89	5,452
1999	84,690.10	42,785	45,876	38,814	23.01	1,687
2000	89,553.44	44,329	47,532	42,022	22.95	1,831
2001	723,885.31	348,623	373,809	350,076	23.14	15,129
2002	42,181.45	19,800	21,230	20,951	23.17	904
2003	180,418.61	82,668	88,640	91,778	23.06	3,980
2004	145,870.90	64,767	69,446	76,425	23.17	3,298
2005	166,697.00	71,763	76,947	89,750	23.15	3,877
2006	139,747.63	58,107	62,305	77,443	23.18	3,341
2007	875,496.72	351,424	376,812	498,684	23.11	21,579
2008	79,153.66	30,411	32,608	46,546	23.24	2,003
2009	54,033.16	19,917	21,356	32,677	23.13	1,413
2010	195,896.61	68,564	73,517	122,379	23.21	5,273
2011	314,436.45	104,141	111,665	202,772	23.22	8,733
2012	49,337.32	15,383	16,494	32,843	23.17	1,417
2013	122,475.44	35,604	38,176	84,299	23.18	3,637
2014	163,714.63	43,974	47,151	116,564	23.15	5,035
2015	94,752.59	23,233	24,911	69,841	23.08	3,026
2016	607,720.95	133,942	143,619	464,102	23.00	20,178
2017	58,110.98	11,215	12,025	46,086	22.99	2,005
2018	71,660.41	11,802	12,655	59,006	22.82	2,586
2019	6,728.79	900	965	5,764	22.68	254

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 12-2047 NET SALVAGE PERCENT.. 0						
2020	45,607.36	4,561	4,891	40,717	22.50	1,810
2021	221,165.06	14,066	15,082	206,083	22.08	9,333
2022	259,028.62	6,035	6,471	252,558	20.96	12,050
	11,902,876.00	5,545,472	5,946,102	5,956,774		260,724
PNG - EMPIRE YARD - MINOR STRUCTURES INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 3-2022 NET SALVAGE PERCENT.. 0						
1960	27,374.98	27,375	27,375			
1961	2,250.14	2,250	2,250			
1962	11,395.40	11,395	11,395			
1964	212.41	212	212			
1965	479.69	480	480			
1972	4,846.95	4,847	4,847			
1973	59,338.04	59,338	59,338			
1976	674.99	675	675			
1977	9,114.69	9,115	9,115			
1978	24,124.85	24,125	24,125			
1979	540.75	541	541			
1980	8,726.53	8,727	8,727			
1981	52,430.77	52,431	52,431			
1982	22,292.87	22,293	22,293			
1984	11,417.15	11,417	11,417			
1986	31,130.64	31,131	31,131			
1987	11,362.33	11,362	11,362			
1988	15,773.37	15,773	15,773			
1989	8,654.63	8,655	8,655			
1990	94,337.02	94,337	94,337			
1992	6,049.58	6,050	6,050			
1993	1,598.34	1,598	1,598			
1994	38,859.45	38,859	38,859			
1995	4,586.75	4,587	4,587			
1996	1,532.27	1,532	1,532			
1997	1,129.92	1,130	1,130			
1998	3,483.10	3,483	3,483			
2001	6,551.41	6,551	6,551			
2002	8,685.69	8,686	8,686			

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
2003	26,975.97	26,976	26,976			
2004	262,708.52	262,709	262,709			
2005	28,203.02	28,203	28,203			
2008	29,302.79	29,303	29,303			
2010	189,349.18	189,349	189,349			
2011	217,404.63	217,405	217,405			
2014	19,697.18	19,697	19,697			
2016	36,430.01	36,430	36,430			
2017	42,967.09	42,967	42,967			
2018	58,528.05	58,528	58,528			
2019	838,990.00	838,990	838,990			
	2,219,511.15	2,219,512	2,219,511			
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2001	6,479.79	2,884	3,207	3,272	26.81	122
2002	3,717,459.49	1,608,173	1,788,470	1,928,990	26.89	71,736
2003	86,366.70	36,205	40,264	46,103	27.01	1,707
2004	114,455.34	46,583	51,806	62,650	26.95	2,325
2005	21,018.75	8,277	9,205	11,814	26.94	439
2006	69,562.49	26,399	29,359	40,204	26.98	1,490
2007	23,610.52	8,599	9,563	14,047	27.06	519
2008	35,659.63	12,459	13,856	21,804	27.00	808
2009	2,413.42	805	895	1,518	26.99	56
2010	43,728.67	13,827	15,377	28,351	27.03	1,049
2011	22,599.66	6,730	7,485	15,115	27.11	558
2012	5,648.26	1,578	1,755	3,893	27.09	144
2013	10,825.90	2,818	3,134	7,692	27.00	285
2014	81,905.36	19,633	21,834	60,071	26.96	2,228
2015	2,283.12	498	554	1,729	26.87	64
2016	41,255.41	8,045	8,947	32,308	26.83	1,204
2017	11,058.96	1,886	2,097	8,962	26.76	335
2018	113,373.18	16,428	18,270	95,103	26.56	3,581
2019	931,227.37	109,140	121,376	809,851	26.35	30,734

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2020	15,591.87	1,364	1,517	14,075	26.07	540
2021	84,279.77	4,678	5,202	79,077	25.53	3,097
2022	815,637.96	16,639	18,504	797,134	24.01	33,200
	6,256,441.62	1,953,648	2,172,677	4,083,765		156,221
PNG - BLOOMSBURG						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2059						
NET SALVAGE PERCENT.. 0						
1907	12.46	10	11	1	12.60	
1909	57.76	48	53	4	13.16	
1910	136.78	114	127	10	13.44	1
1912	15.65	13	14	1	14.00	
1915	2,677.72	2,181	2,426	252	14.84	17
1930	25,467.58	19,350	21,519	3,948	19.10	207
1933	41.56	31	34	7	19.96	
1934	68.83	51	57	12	20.24	1
1944	71.26	50	56	16	23.06	1
1968	646.66	385	428	218	29.03	8
1974	842.24	474	527	315	30.21	10
1976	103,603.50	57,151	63,558	40,045	30.57	1,310
1977	20,984.75	11,453	12,737	8,248	30.74	268
1978	83.39	45	50	33	30.91	1
1980	1,544.84	815	906	638	31.23	20
1981	984.45	513	571	414	31.39	13
1983	3,281.25	1,866	2,075	1,206	29.94	40
1984	4,173.75	2,346	2,609	1,565	29.99	52
1987	1,513.65	817	909	605	30.29	20
1988	13,483.87	7,164	7,967	5,517	30.44	181
1991	1,061.00	535	595	466	31.00	15
1996	7,009.14	3,213	3,573	3,436	31.31	110
1998	26,471.23	11,610	12,912	13,560	31.36	432
2000	16,127.75	6,712	7,464	8,663	31.56	274
2001	5,503.51	2,225	2,474	3,029	31.69	96
2003	14,245.64	5,416	6,023	8,222	31.78	259
2007	20,621.98	6,743	7,499	13,123	31.90	411
2008	5,631.08	1,756	1,953	3,678	32.01	115
2010	19,035.29	5,353	5,953	13,082	31.95	409

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - BLOOMSBURG						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2059						
NET SALVAGE PERCENT.. 0						
2011	187,198.19	49,514	55,065	132,133	31.98	4,132
2014	780,161.32	164,458	182,896	597,266	31.82	18,770
2015	32,204.52	6,158	6,848	25,356	31.72	799
2016	12,899.16	2,197	2,443	10,456	31.67	330
2018	55,602.72	6,984	7,767	47,836	31.34	1,526
2019	14,930.36	1,515	1,685	13,246	30.98	428
	1,378,394.84	379,266	421,786	956,609		30,256
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1971	256,323.25	214,607	238,667	17,656	6.51	2,712
1972	1,414.08	1,172	1,303	111	6.84	16
1973	1,341.92	1,101	1,224	117	7.19	16
1974	12,886.39	10,457	11,629	1,257	7.54	167
1975	137,263.48	110,154	122,504	14,760	7.90	1,868
1976	267,126.39	211,831	235,580	31,546	8.28	3,810
1978	1,694.83	1,311	1,458	237	9.07	26
1983	1,716.01	1,363	1,516	200	10.25	20
1984	8,218.63	6,424	7,144	1,074	10.76	100
1986	1,468.08	1,115	1,240	228	11.58	20
1987	63,259.26	47,381	52,693	10,566	11.90	888
1988	164,987.37	121,233	134,825	30,163	12.45	2,423
1989	18,195.40	13,104	14,573	3,622	13.01	278
1990	3,271.23	2,318	2,578	693	13.37	52
1992	902.42	614	683	220	14.34	15
1994	8,464.53	5,500	6,117	2,348	15.36	153
1995	470.22	297	330	140	15.98	9
1996	2,266.54	1,399	1,556	711	16.42	43
1997	23,123.73	13,916	15,476	7,648	16.87	453
1998	20,630.97	12,030	13,379	7,252	17.52	414
1999	4,962.51	2,811	3,126	1,836	17.99	102
2000	407,096.61	222,600	247,556	159,540	18.65	8,554
2001	15,763.16	8,337	9,272	6,491	19.15	339
2002	131,065.22	66,896	74,396	56,669	19.66	2,882
2003	14,137.33	6,947	7,726	6,411	20.18	318
2004	40,617.24	19,163	21,311	19,306	20.71	932
2005	19,878.71	8,941	9,943	9,935	21.41	464

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
2007	62,879.67	25,630	28,503	34,376	22.52	1,526
2008	2,272.69	877	975	1,297	23.09	56
2009	9,240.13	3,368	3,746	5,495	23.54	233
2010	66,063.64	22,541	25,068	40,996	24.13	1,699
2011	411,833.93	130,716	145,371	266,463	24.73	10,775
2012	83,940.09	24,678	27,445	56,495	25.21	2,241
2014	113,861.66	27,873	30,998	82,864	26.22	3,160
2015	183,656.84	40,221	44,730	138,927	26.75	5,194
2016	68,315.79	13,185	14,663	53,653	27.17	1,975
2017	316,762.84	52,614	58,513	258,250	27.61	9,353
2018	369,467.98	51,208	56,949	312,519	27.97	11,173
2019	368,864.11	40,796	45,370	323,494	28.15	11,492
2020	667,838.53	54,228	60,308	607,531	28.27	21,490
2021	1,439,248.27	73,114	81,311	1,357,937	28.00	48,498
2022	806,705.34	15,005	16,687	790,018	26.45	29,868
	6,599,497.02	1,689,076	1,878,443	4,721,054		185,807
CPG - STROUDSBURG DISTRICT OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. 0						
1970	2,405.60	1,966	2,406			
1971	856.40	698	856			
1977	337.88	269	331	7	10.30	1
1989	1,796.89	1,372	1,688	109	10.36	11
1991	11,012.42	8,290	10,200	812	10.34	79
1993	1,815.54	1,344	1,654	162	10.34	16
1994	163,361.24	119,646	147,213	16,149	10.41	1,551
1995	8,885.02	6,451	7,937	948	10.38	91
1996	549.62	395	486	64	10.40	6
1997	6,779.59	4,806	5,913	866	10.47	83
1998	2,746.90	1,925	2,369	378	10.47	36
2000	60,363.60	41,289	50,802	9,562	10.39	920
2005	3,322.01	2,081	2,560	762	10.43	73
2006	4,194.08	2,568	3,160	1,034	10.45	99
2008	48,795.58	28,301	34,822	13,974	10.50	1,331
2010	2,580.94	1,404	1,727	853	10.49	81
2011	12,737.88	6,664	8,199	4,538	10.48	433
2015	136,006.52	56,824	69,916	66,090	10.45	6,324

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ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

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RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - STROUDSBURG DISTRICT OFFICE INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2033 NET SALVAGE PERCENT.. 0						
2016	124,033.08	47,567	58,526	65,507	10.45	6,269
2017	98,192.15	33,857	41,658	56,534	10.45	5,410
2018	17,582.52	5,292	6,511	11,071	10.45	1,059
2021	55,041.79	6,990	8,601	46,441	10.31	4,504
2022	37,576.07	1,774	2,183	35,393	10.08	3,511
	800,973.32	381,773	469,718	331,255		31,888
CPG - PORT ALLEGANY OPERATIONS CENTER INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2042 NET SALVAGE PERCENT.. 0						
1990	102.66	66	81	21	18.26	1
1993	737,722.10	454,879	559,665	178,057	18.34	9,709
1994	3,067.62	1,862	2,291	777	18.45	42
1995	8,454.84	5,069	6,237	2,218	18.37	121
1996	2,642.22	1,562	1,922	720	18.34	39
1997	9,729.43	5,657	6,960	2,769	18.36	151
1999	1,707.29	955	1,175	532	18.52	29
2001	413,531.82	222,273	273,476	140,056	18.50	7,571
2003	84,810.24	43,491	53,510	31,301	18.52	1,690
2004	10,531.21	5,260	6,472	4,060	18.54	219
2005	32,296.91	15,658	19,265	13,032	18.60	701
2007	33,973.83	15,431	18,986	14,988	18.63	805
2009	25,458.89	10,723	13,193	12,266	18.55	661
2010	22,614.64	9,102	11,199	11,416	18.56	615
2011	16,744.15	6,393	7,866	8,878	18.62	477
2012	2,373.40	857	1,054	1,319	18.57	71
2013	4,123.80	1,395	1,716	2,407	18.59	129
2014	18,579.62	5,827	7,169	11,410	18.60	613
2015	135,653.72	39,068	48,068	87,586	18.54	4,724
2016	10,271.87	2,671	3,286	6,986	18.50	378
2018	11,861.90	2,327	2,863	8,999	18.44	488
2019	5,778.08	926	1,139	4,639	18.33	253
2020	32,163.20	3,885	4,780	27,383	18.20	1,505
2021	4,204.00	324	399	3,805	17.96	212
2022	323,158.46	9,113	11,212	311,946	17.20	18,136
	1,951,555.90	864,774	1,063,983	887,573		49,340

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - POTTSVILLE METER SHOP						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. 0						
1937	1,234.84	947	1,165	70	18.10	4
1961	294.42	203	250	45	21.91	2
1970	377.45	246	303	75	22.96	3
1976	1,808.65	1,126	1,385	423	23.54	18
1982	26,509.40	16,855	20,738	5,772	23.20	249
1987	357.42	214	263	94	23.67	4
1988	95.00	56	69	26	23.64	1
1989	24.29	14	17	7	23.65	
1990	2,123.00	1,228	1,511	612	23.68	26
1992	4,760.80	2,672	3,288	1,473	23.85	62
1993	2,703.40	1,491	1,834	869	23.98	36
1995	18,973.34	10,122	12,454	6,520	24.05	271
1996	4,307.22	2,260	2,781	1,527	24.01	64
1997	9,271.45	4,776	5,876	3,395	24.00	141
1998	11,191.78	5,648	6,949	4,243	24.04	176
2000	519,130.02	249,961	307,542	211,588	24.23	8,732
2001	12,387.00	5,832	7,175	5,212	24.16	216
2002	2,306.86	1,055	1,298	1,009	24.34	41
2004	6,184.42	2,677	3,294	2,891	24.24	119
2009	184,472.34	65,746	80,891	103,581	24.38	4,249
2014	17,931.59	4,648	5,719	12,213	24.29	503
2017	149,837.36	27,855	34,272	115,566	24.09	4,797
	976,282.05	405,632	499,074	477,208		19,714
CPG - LEHIGHTON OPERATIONS CENTER						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 8-2073						
NET SALVAGE PERCENT.. 0						
2022	150,681.29	2,230	2,744	147,937	33.28	4,445
	150,681.29	2,230	2,744	147,937		4,445

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1947	88.33	88	88			
1949	62.10	62	62			
1950	1,750.46	1,730	1,750			
1954	82.09	79	82			
1955	2,524.74	2,412	2,525			
1959	8,481.65	7,862	8,482			
1960	23,176.48	21,317	23,176			
1961	1,347.50	1,230	1,348			
1962	1,123.26	1,017	1,123			
1963	530.30	476	530			
1964	650.44	579	650			
1965	756.41	668	756			
1966	1,375.16	1,205	1,375			
1967	93,390.59	81,110	93,391			
1968	21,420.99	18,443	21,421			
1969	4,193.10	3,578	4,193			
1970	1,826.32	1,544	1,826			
1971	1,842.02	1,542	1,842			
1972	3,936.95	3,264	3,937			
1973	2,566.84	2,105	2,567			
1974	3,035.86	2,464	3,036			
1975	12,010.65	9,639	11,904	107	7.90	14
1977	458.66	359	443	15	8.67	2
1978	3,473.82	2,686	3,317	157	9.07	17
1979	402.24	307	379	23	9.49	2
1980	1,246.95	938	1,158	89	9.92	9
1981	3,845.85	2,849	3,518	327	10.37	32
1982	4,422.05	3,564	4,401	21	9.75	2
1983	10,964.16	8,706	10,752	213	10.25	21
1984	481.79	377	466	16	10.76	1
1985	12,396.87	9,577	11,827	570	11.04	52
1986	990.08	752	929	61	11.58	5
1988	1,732.16	1,273	1,572	160	12.45	13
1989	13,493.07	9,718	12,001	1,492	13.01	115
1990	1,467.02	1,039	1,283	184	13.37	14
1991	230,947.17	160,046	197,652	33,295	13.95	2,387
1992	43,627.18	29,675	36,648	6,979	14.34	487
1993	17,666.93	11,727	14,483	3,184	14.94	213
1994	110,736.85	71,957	88,865	21,872	15.36	1,424
1995	121,110.90	76,603	94,602	26,508	15.98	1,659
1996	38,413.91	23,717	29,290	9,124	16.42	556
1997	707,112.52	425,540	525,530	181,583	16.87	10,764

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1998	242,850.52	141,606	174,879	67,971	17.52	3,880
1999	273,981.29	155,183	191,646	82,335	17.99	4,577
2000	43,776.95	23,937	29,561	14,215	18.65	762
2001	176,958.76	93,593	115,585	61,374	19.15	3,205
2002	89,458.63	45,660	56,389	33,070	19.66	1,682
2003	33,486.09	16,455	20,321	13,165	20.18	652
2004	722,980.57	341,102	421,251	301,730	20.71	14,569
2005	694,888.21	312,561	386,004	308,884	21.41	14,427
2006	226,341.44	97,100	119,916	106,426	21.96	4,846
2007	124,072.15	50,572	62,455	61,617	22.52	2,736
2008	648,301.51	250,050	308,804	339,497	23.09	14,703
2009	318,403.94	116,058	143,328	175,076	23.54	7,437
2010	121,597.41	41,489	51,238	70,360	24.13	2,916
2011	81,381.09	25,830	31,899	49,482	24.73	2,001
2012	15,294.93	4,497	5,554	9,741	25.21	386
2013	152,595.60	41,170	50,844	101,752	25.71	3,958
2014	185,601.43	45,435	56,111	129,491	26.22	4,939
2015	351,076.18	76,886	94,952	256,124	26.75	9,575
2016	260,553.66	50,287	62,103	198,451	27.17	7,304
2017	93,835.87	15,586	19,248	74,588	27.61	2,701
2018	297,865.49	41,284	50,985	246,881	27.97	8,827
2019	199,467.50	22,061	27,245	172,223	28.15	6,118
2020	787,053.30	63,909	78,926	708,128	28.27	25,049
2021	807,832.28	41,038	50,681	757,152	28.00	27,041
2022	1,612,699.98	29,996	37,044	1,575,656	26.45	59,571
	10,073,517.20	3,147,169	3,872,151	6,201,366		251,651
	112,227,654.49	38,884,513	42,197,098	70,030,557		3,571,458

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.6 3.18

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	58,882.74	57,411	37,125	21,757	0.50	21,757
2004	19,545.79	18,080	11,692	7,854	1.50	5,236
2005	12,973.40	11,352	7,341	5,633	2.50	2,253
2006	15,741.19	12,986	8,398	7,344	3.50	2,098
2007	98,862.25	76,618	49,546	49,317	4.50	10,959
2008	10,904.48	7,906	5,112	5,792	5.50	1,053
2009	196,763.79	132,816	85,887	110,877	6.50	17,058
2010	29,674.64	18,547	11,994	17,681	7.50	2,357
2013	49,177.44	23,359	15,105	34,072	10.50	3,245
2014	164,928.32	70,095	45,328	119,601	11.50	10,400
2015	142,233.63	53,338	34,491	107,742	12.50	8,619
2016	156,448.43	50,846	32,880	123,568	13.50	9,153
2017	694,772.06	191,062	123,552	571,220	14.50	39,394
2018	365,293.03	82,191	53,149	312,144	15.50	20,138
2019	260,157.81	45,528	29,441	230,717	16.50	13,983
2020	235,363.22	29,420	19,025	216,339	17.50	12,362
2021	186,194.50	13,965	9,031	177,164	18.50	9,576
2022	239,796.94	5,995	3,877	235,920	19.50	12,098
	2,937,713.66	901,515	582,972	2,354,742		201,739
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	12,589.63	12,275	12,215	374	0.50	374
2004	826.89	765	761	66	1.50	44
2005	1,086.91	951	946	141	2.50	56
2006	1,234.22	1,018	1,013	221	3.50	63
2007	1,312.22	1,017	1,012	300	4.50	67
2008	24,417.03	17,702	17,616	6,801	5.50	1,237
2010	2,239.24	1,400	1,393	846	7.50	113
2011	20,678.25	11,890	11,832	8,846	8.50	1,041
2014	33,759.66	14,348	14,278	19,481	11.50	1,694
2015	35,177.20	13,191	13,127	22,050	12.50	1,764
2016	233,275.70	75,815	75,447	157,829	13.50	11,691
2017	400,100.57	110,028	109,493	290,607	14.50	20,042
2018	31,187.62	7,017	6,983	24,205	15.50	1,562
2019	69,735.23	12,204	12,145	57,591	16.50	3,490

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	115,739.37	14,467	14,397	101,343	17.50	5,791
2021	61,990.92	4,649	4,626	57,365	18.50	3,101
2022	50,000.00	1,250	1,244	48,756	19.50	2,500
	1,095,350.66	299,987	298,529	796,822		54,630
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	2,532.25	2,469	2,387	145	0.50	145
2004	11,966.55	11,069	10,701	1,265	1.50	843
2006	1,393.32	1,149	1,111	283	3.50	81
2007	4,828.41	3,742	3,618	1,211	4.50	269
2010	1,926.82	1,204	1,164	763	7.50	102
2014	4,225.61	1,796	1,736	2,489	11.50	216
2015	64,028.79	24,011	23,213	40,816	12.50	3,265
2016	22,950.78	7,459	7,211	15,740	13.50	1,166
2017	29,884.80	8,218	7,945	21,940	14.50	1,513
2018	66,579.64	14,980	14,482	52,098	15.50	3,361
2019	9,728.37	1,702	1,645	8,083	16.50	490
2020	395,875.29	49,484	47,839	348,036	17.50	19,888
2021	17,352.44	1,301	1,258	16,095	18.50	870
2022	110,598.61	2,765	2,673	107,926	19.50	5,535
	743,871.68	131,349	126,983	616,889		37,744
	4,776,936.00	1,332,851	1,008,484	3,768,453		294,113

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.8   6.16

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	4,313.90	3,235	3,455	859	2.50	344
2016	42,502.55	27,627	29,503	13,000	3.50	3,714
2017	3,747.59	2,061	2,201	1,547	4.50	344
2020	18,196.00	4,549	4,858	13,338	7.50	1,778
2021	30,929.53	4,639	4,954	25,976	8.50	3,056
	99,689.57	42,111	44,970	54,720		9,236
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	1,637.58	1,556	1,432	205	0.50	205
2015	7,913.29	5,935	5,463	2,451	2.50	980
2016	5,541.48	3,602	3,315	2,226	3.50	636
2017	8,554.22	4,705	4,330	4,224	4.50	939
2018	2,800.72	1,260	1,160	1,641	5.50	298
2021	67,496.24	10,124	9,318	58,178	8.50	6,844
	93,943.53	27,182	25,018	68,926		9,902
	193,633.10	69,293	69,988	123,646		19,138

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 9.88

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	20,690.72	6,207	4,598	16,093	3.50	4,598
	20,690.72	6,207	4,598	16,093		4,598
PNG						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	285,879.24	257,291	219,873	66,007	0.50	66,007
2021	46,130.82	13,839	11,826	34,304	3.50	9,801
	332,010.06	271,130	231,699	100,311		75,808
CPG						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	289,585.10	260,627	248,754	40,831	0.50	40,831
2021	20,690.76	6,207	5,924	14,767	3.50	4,219
	310,275.86	266,834	254,678	55,598		45,050
	662,976.64	544,171	490,975	172,002		125,456

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.4 18.92

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2020	779,019.38	276,708	312,461	466,558	4.54	102,766
2021	1,131,445.59	248,918	281,080	850,365	5.32	159,843
2022	547,102.11	40,923	46,211	500,892	6.18	81,050
	2,457,567.08	566,549	639,752	1,817,815		343,659
PNG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2018	259,448.53	150,480	135,448	124,001	3.26	38,037
2020	82,239.72	29,212	26,294	55,946	4.54	12,323
2022	308,592.18	23,083	20,777	287,815	6.18	46,572
	650,280.43	202,775	182,519	467,761		96,932
CPG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2006	1,056.16	1,000	1,044	12	0.92	12
2019	67,537.69	32,215	33,633	33,905	3.84	8,829
2020	87,761.08	31,173	32,545	55,216	4.54	12,162
2021	94,492.42	20,788	21,703	72,790	5.32	13,682
2022	256,172.77	19,162	20,005	236,167	6.18	38,215
	507,020.12	104,338	108,930	398,090		72,900
	3,614,867.63	873,662	931,201	2,683,666		513,491

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 14.20

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	146,963.60	93,998	106,755	40,209	3.66	10,986
2018	1,140,369.30	556,728	632,283	508,086	4.72	107,645
2019	501,361.57	197,236	224,004	277,358	5.40	51,363
2020	4,688,211.34	1,355,831	1,539,835	3,148,376	6.14	512,765
2021	721,301.61	127,887	145,243	576,059	6.96	82,767
2022	4,084,021.26	244,224	277,368	3,806,653	7.85	484,924
	11,282,228.68	2,575,904	2,925,488	8,356,741		1,250,450
PNG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	654,931.06	418,894	380,316	274,615	3.66	75,031
2018	566,930.32	276,775	251,285	315,645	4.72	66,874
2019	1,655,159.35	651,140	591,173	1,063,987	5.40	197,035
2020	3,573,356.29	1,033,415	938,242	2,635,114	6.14	429,172
2021	738,968.44	131,019	118,953	620,016	6.96	89,083
2022	2,303,154.17	137,729	125,045	2,178,109	7.85	277,466
	9,492,499.63	2,648,972	2,405,013	7,087,487		1,134,661
CPG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2004	1,670.51	1,545	1,590	81	1.50	54
2005	17,869.24	16,324	16,797	1,072	1.66	646
2006	66,740.29	60,013	61,752	4,988	1.85	2,696
2009	69,992.19	59,437	61,159	8,833	2.40	3,680
2010	11,748.46	9,737	10,019	1,729	2.58	670
2019	1,425,017.03	560,602	576,848	848,169	5.40	157,068
2020	3,285,437.37	950,148	977,683	2,307,755	6.14	375,856
2021	463,858.40	82,242	84,625	379,233	6.96	54,488
2022	1,911,917.53	114,333	117,646	1,794,271	7.85	228,570
	7,254,251.02	1,854,381	1,908,120	5,346,131		823,728
	28,028,979.33	7,079,257	7,238,621	20,790,359		3,208,839

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5   11.45

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2019	77,386.14	25,189	4,673	72,714	7.25	10,030
2022	399,578.23	18,860	3,498	396,080	10.09	39,255
	476,964.37	44,049	8,171	468,793		49,285
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	428,974.26	176,823	153,659	275,316	6.42	42,884
2020	467,180.42	109,694	95,324	371,857	8.15	45,627
2022	225,314.25	10,635	9,242	216,072	10.09	21,414
	1,121,468.93	297,152	258,224	863,245		109,925
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2004	142,639.00	129,031	135,624	7,015	1.95	3,597
2005	81,280.60	72,258	75,950	5,330	2.19	2,434
2006	199,911.41	174,483	183,399	16,513	2.40	6,880
2019	603,303.32	196,375	206,409	396,894	7.25	54,744
2020	491,775.83	115,469	121,369	370,407	8.15	45,449
2022	187,036.61	8,828	9,279	177,758	10.09	17,617
	1,705,946.77	696,444	732,030	973,917		130,721
	3,304,380.07	1,037,645	998,425	2,305,955		289,931

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.0   8.77

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	449,208.13	185,164	226,641	222,567	6.42	34,668
2019	360,930.75	117,483	143,800	217,131	7.25	29,949
2020	499,231.88	117,220	143,478	355,754	8.15	43,651
2021	307,655.78	43,503	53,248	254,408	9.10	27,957
2022	622,986.35	29,405	35,992	586,995	10.09	58,176
	2,240,012.89	492,775	603,158	1,636,855		194,401
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	376,636.13	155,249	131,664	244,972	6.42	38,158
2019	302,095.18	98,332	83,394	218,702	7.25	30,166
2020	342,490.41	80,417	68,200	274,290	8.15	33,655
2022	351,282.58	16,581	14,062	337,221	10.09	33,421
	1,372,504.30	350,579	297,320	1,075,184		135,400
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2001	51,781.44	48,763	51,341	440	1.33	331
2002	70,815.38	65,908	69,393	1,423	1.53	930
2005	250,734.82	222,903	234,688	16,047	2.19	7,327
2019	305,566.54	99,462	104,720	200,846	7.25	27,703
2020	514,801.20	120,875	127,266	387,536	8.15	47,550
2022	291,604.74	13,764	14,492	277,113	10.09	27,464
	1,485,304.12	571,675	601,899	883,405		111,305
	5,097,821.31	1,415,029	1,502,377	3,595,444		441,106

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.2   8.65

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2012	12,858.54	8,358	9,938	2,920	5.65	517
2016	281,546.27	134,326	159,722	121,824	7.12	17,110
2019	25,776.42	7,207	8,570	17,207	9.02	1,908
2022	261,368.35	11,004	13,084	248,284	11.38	21,818
	581,549.58	160,895	191,314	390,236		41,353
PNG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1998	1,693.06	1,497	1,392	302	3.20	94
2004	779.65	630	586	194	4.38	44
2011	39,431.80	26,711	24,829	14,602	5.48	2,665
2018	74,053.22	25,963	24,134	49,919	8.34	5,985
2020	298,333.42	61,009	56,711	241,622	9.72	24,858
2021	337,438.86	42,180	39,209	298,230	10.50	28,403
2022	147,381.86	6,205	5,768	141,614	11.38	12,444
	899,111.87	164,195	152,629	746,483		74,493
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1994	2,495.03	2,297	2,433	62	2.46	25
2001	36,167.86	30,714	32,538	3,630	3.82	950
2002	5,584.91	4,671	4,948	637	4.01	159
2003	16,177.56	13,313	14,103	2,074	4.20	494
2004	39,848.07	32,213	34,126	5,722	4.38	1,306
2005	165,045.82	130,848	138,617	26,429	4.57	5,783
2006	19,504.79	15,159	16,059	3,446	4.73	729
2009	12,533.28	9,069	9,607	2,926	5.16	567
2017	7,069.44	2,947	3,122	3,947	7.69	513
2019	69,484.12	19,428	20,581	48,903	9.02	5,422

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2020	140,515.06	28,735	30,441	110,074	9.72	11,324
2021	247,120.32	30,890	32,724	214,396	10.50	20,419
2022	122,351.84	5,151	5,457	116,895	11.38	10,272
	883,898.10	325,435	344,757	539,141		57,963
	2,364,559.55	650,525	688,700	1,675,860		173,809

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.6 7.35

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	1,768.11	1,636	1,643	125	1.50	83
	1,768.11	1,636	1,643	125		83
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	5,589.99	2,376	2,377	3,213	11.50	279
2018	10,248.45	2,306	2,306	7,942	15.50	512
	15,838.44	4,682	4,683	11,155		791
	17,606.55	6,318	6,326	11,280		874

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.9 4.96

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	344,961.13	336,337	341,021	3,940	0.50	3,940
2004	376,497.34	348,260	353,110	23,387	1.50	15,591
2005	585,131.98	511,990	519,121	66,011	2.50	26,404
2006	533,535.20	440,167	446,297	87,238	3.50	24,925
2007	637,237.38	493,859	500,737	136,500	4.50	30,333
2008	236,121.16	171,188	173,572	62,549	5.50	11,373
2009	267,438.49	180,521	183,035	84,403	6.50	12,985
2010	162,964.81	101,853	103,272	59,693	7.50	7,959
2011	451,363.00	259,534	263,149	188,214	8.50	22,143
2012	368,654.37	193,544	196,240	172,415	9.50	18,149
2013	792,113.30	376,254	381,494	410,619	10.50	39,107
2014	476,076.46	202,332	205,150	270,926	11.50	23,559
2015	1,648,297.12	618,111	626,720	1,021,577	12.50	81,726
2016	1,270,294.92	412,846	418,596	851,699	13.50	63,089
2017	1,830,420.92	503,366	510,377	1,320,044	14.50	91,038
2018	915,728.07	206,039	208,909	706,819	15.50	45,601
2019	1,013,890.01	177,431	179,902	833,988	16.50	50,545
2020	1,692,662.34	211,583	214,530	1,478,132	17.50	84,465
2021	1,785,140.52	133,886	135,751	1,649,390	18.50	89,156
2022	2,220,574.48	55,514	56,287	2,164,287	19.50	110,989
	17,609,103.00	5,934,615	6,017,270	11,591,833		853,077
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	110,682.26	107,915	107,960	2,722	0.50	2,722
2004	270,994.91	250,670	250,775	20,220	1.50	13,480
2005	107,276.26	93,867	93,906	13,370	2.50	5,348
2006	272,070.63	224,458	224,552	47,519	3.50	13,577
2007	397,958.98	308,418	308,547	89,412	4.50	19,869
2008	194,881.81	141,289	141,348	53,534	5.50	9,733
2009	386,652.36	260,990	261,099	125,553	6.50	19,316
2010	528,508.76	330,318	330,456	198,053	7.50	26,407
2011	46,412.17	26,687	26,698	19,714	8.50	2,319
2012	106,370.79	55,845	55,868	50,502	9.50	5,316
2013	245,409.98	116,570	116,619	128,791	10.50	12,266
2014	495,061.18	210,401	210,489	284,572	11.50	24,745
2015	960,119.93	360,045	360,195	599,925	12.50	47,994
2016	582,263.35	189,236	189,315	392,948	13.50	29,107

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	608,859.13	167,436	167,506	441,353	14.50	30,438
2018	1,012,779.35	227,875	227,970	784,809	15.50	50,633
2019	536,030.46	93,805	93,844	442,186	16.50	26,799
2020	1,296,129.90	162,016	162,084	1,134,046	17.50	64,803
2021	1,226,021.61	91,952	91,990	1,134,031	18.50	61,299
2022	1,470,338.24	36,758	36,773	1,433,565	19.50	73,516
	10,854,822.06	3,456,551	3,457,995	7,396,827		539,687
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	190,336.67	185,578	162,675	27,662	0.50	27,662
2004	403,566.38	373,299	327,228	76,339	1.50	50,893
2005	471,228.17	412,325	361,437	109,791	2.50	43,916
2006	277,067.07	228,580	200,370	76,698	3.50	21,914
2007	507,181.09	393,065	344,554	162,627	4.50	36,139
2008	544,153.86	394,512	345,823	198,331	5.50	36,060
2009	190,844.18	128,820	112,922	77,923	6.50	11,988
2010	675,112.97	421,946	369,871	305,242	7.50	40,699
2011	41,307.18	23,752	20,821	20,487	8.50	2,410
2012	185,811.11	97,551	85,512	100,299	9.50	10,558
2013	268,626.03	127,597	111,849	156,777	10.50	14,931
2014	510,814.37	217,096	190,303	320,512	11.50	27,871
2015	362,285.21	135,857	119,090	243,195	12.50	19,456
2016	632,442.31	205,544	180,177	452,266	13.50	33,501
2017	243,698.39	67,017	58,746	184,952	14.50	12,755
2018	534,429.05	120,247	105,407	429,022	15.50	27,679
2019	795,631.49	139,236	122,052	673,579	16.50	40,823
2020	463,388.36	57,924	50,775	412,613	17.50	23,578
2021	934,658.67	70,099	61,448	873,211	18.50	47,201
2022	782,352.30	19,559	17,145	765,207	19.50	39,241
	9,014,934.86	3,819,604	3,348,203	5,666,732		569,275
	37,478,859.92	13,210,770	12,823,468	24,655,392		1,962,039

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.6 5.24

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	552.73	207	201	351	12.50	28
2016	1,085.72	353	344	742	13.50	55
2017	330,397.55	90,859	88,444	241,953	14.50	16,686
2018	105,742.64	23,792	23,160	82,583	15.50	5,328
	437,778.64	115,211	112,149	325,630		22,097

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.7 5.05

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2000	6,498.36	5,600	6,143	356	3.61	99
2001	30,317.91	25,746	28,242	2,076	3.82	543
2002	3,719.59	3,111	3,413	307	4.01	77
2003	35,492.23	29,207	32,038	3,454	4.20	822
2004	54,943.24	44,416	48,721	6,222	4.38	1,421
2005	14,736.28	11,683	12,815	1,921	4.57	420
2006	28,808.32	22,390	24,560	4,248	4.73	898
2007	37,931.66	28,866	31,664	6,268	4.87	1,287
2009	64,652.45	46,783	51,318	13,335	5.16	2,584
2013	15,373.86	9,480	10,399	4,975	5.91	842
2018	220,480.47	77,300	84,793	135,688	8.34	16,270
2019	308,929.87	86,377	94,749	214,180	9.02	23,745
2020	1,614,013.94	330,066	362,059	1,251,955	9.72	128,802
2021	76,359.04	9,545	10,470	65,889	10.50	6,275
	2,512,257.22	730,570	801,383	1,710,874		184,085
PNG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2003	68,109.74	56,048	66,799	1,311	4.20	312
2004	167,248.57	135,204	161,138	6,111	4.38	1,395
2007	13,369.18	10,174	12,126	1,244	4.87	255
2008	35,075.31	26,089	31,093	3,982	4.99	798
2009	48,114.46	34,816	41,494	6,620	5.16	1,283
2010	12,089.03	8,493	10,122	1,967	5.29	372
2018	1,346,981.57	472,252	562,836	784,145	8.34	94,022
2020	783,198.88	160,164	190,886	592,313	9.72	60,938
2021	45,428.50	5,679	6,768	38,660	10.50	3,682
	2,519,615.24	908,919	1,083,262	1,436,353		163,057
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2001	21,592.29	18,336	15,652	5,941	3.82	1,555
2002	30,786.38	25,750	21,980	8,806	4.01	2,196
2003	50,494.67	41,552	35,469	15,026	4.20	3,578
2004	106,224.95	85,872	73,300	32,925	4.38	7,517

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2005	199,925.67	158,501	135,296	64,630	4.57	14,142
2006	32,646.90	25,373	21,658	10,989	4.73	2,323
2009	69,039.30	49,957	42,643	26,396	5.16	5,116
2018	909.08	319	272	637	8.34	76
2019	106,125.88	29,673	25,329	80,797	9.02	8,958
2020	920,993.58	188,343	160,769	760,225	9.72	78,212
	1,538,738.70	623,676	532,368	1,006,371		123,673
	6,570,611.16	2,263,165	2,417,013	4,153,598		470,815

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.8 7.17

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	31,838.36	30,246	27,465	4,374	0.50	4,374
2021	40,712.05	6,107	5,545	35,167	8.50	4,137
	72,550.41	36,353	33,010	39,540		8,511
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	713,351.62	392,343	302,043	411,309	4.50	91,402
2019	33,841.70	11,845	9,119	24,723	6.50	3,804
2021	50,379.19	7,557	5,818	44,561	8.50	5,242
	797,572.51	411,745	316,979	480,594		100,448
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	151.47	129	151			
2015	28,671.36	21,504	28,671			
2017	17,961.49	9,879	17,231	730	4.50	162
2021	21,890.53	3,284	5,728	16,163	8.50	1,902
	68,674.85	34,796	51,782	16,893		2,064
	938,797.77	482,894	401,771	537,027		111,023

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.8   11.83

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	102,456.20	71,719	11,013	91,444	4.50	20,321
2013	51,777.87	32,792	5,035	46,743	5.50	8,499
2014	178,624.07	101,221	15,543	163,082	6.50	25,090
2015	39,471.49	19,736	3,030	36,441	7.50	4,859
2016	32,235.43	13,969	2,145	30,090	8.50	3,540
2017	165,977.94	60,859	9,345	156,633	9.50	16,488
2018	106,282.35	31,885	4,896	101,386	10.50	9,656
2020	146,222.17	24,371	3,742	142,480	12.50	11,398
2022	59,425.00	1,981	304	59,121	14.50	4,077
	882,472.52	358,533	55,053	827,420		103,928
PNG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	48,106.71	46,503	44,328	3,778	0.50	3,778
2009	72,298.45	65,069	62,026	10,272	1.50	6,848
2010	346,189.24	288,490	275,000	71,189	2.50	28,476
2011	26,672.91	20,449	19,493	7,180	3.50	2,051
2012	6,969.59	4,879	4,651	2,319	4.50	515
2014	262,109.02	148,529	141,584	120,525	6.50	18,542
2016	184,658.73	80,018	76,276	108,382	8.50	12,751
2017	64,069.97	23,493	22,394	41,676	9.50	4,387
2018	1,869.95	561	535	1,335	10.50	127
2020	61,699.27	10,283	9,802	51,897	12.50	4,152
2022	89,137.51	2,971	2,832	86,305	14.50	5,952
	1,163,781.35	691,245	658,922	504,859		87,579
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	19,072.92	17,166	16,281	2,792	1.50	1,861
2010	46,085.64	38,405	36,424	9,662	2.50	3,865
2011	70,068.25	53,719	50,948	19,120	3.50	5,463
2012	14,758.99	10,331	9,798	4,961	4.50	1,102
2014	2,414.03	1,368	1,297	1,117	6.50	172
2015	4,956.48	2,478	2,350	2,606	7.50	347
2016	65,279.25	28,287	26,828	38,451	8.50	4,524

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	81,771.73	29,983	28,437	53,335	9.50	5,614
2018	4,477.95	1,343	1,274	3,204	10.50	305
2019	1,267.76	296	281	987	11.50	86
2020	4,259.10	710	673	3,586	12.50	287
2022	29,712.49	990	939	28,774	14.50	1,984
	344,124.59	185,076	175,530	168,595		25,610
	2,390,378.46	1,234,854	889,505	1,500,874		217,117

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.9   9.08

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI HEADQUARTERS BUILDING INTERIM SURVIVOR CURVE.. IOWA 70-R1 PROBABLE RETIREMENT YEAR.. 1-2069 NET SALVAGE PERCENT.. 0						
2019	30,037,912.33	2,955,731	2,745,590	27,292,322	32.09	850,493
2020	1,907,500.04	141,537	131,474	1,776,026	31.17	56,979
2021	671,173.69	32,082	29,801	641,373	29.85	21,487
2022	2,123,767.06	39,502	36,694	2,087,073	26.45	78,906
	34,740,353.12	3,168,852	2,943,559	31,796,794		1,007,865

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.5 2.90

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	7,182.75	7,003	6,194	989	0.50	989
2004	11,896.38	11,004	9,733	2,163	1.50	1,442
2005	39,965.68	34,970	30,931	9,035	2.50	3,614
2006	2,468.81	2,037	1,802	667	3.50	191
2007	878.14	681	602	276	4.50	61
2008	572.40	415	367	205	5.50	37
2009	4,753.12	3,208	2,837	1,916	6.50	295
2010	747,318.56	467,074	413,128	334,191	7.50	44,559
2019	3,525,485.48	616,960	545,702	2,979,783	16.50	180,593
2020	27,303.10	3,413	3,019	24,284	17.50	1,388
	4,367,824.42	1,146,765	1,014,315	3,353,509		233,169

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.4 5.34

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	88,618.09	79,756	68,982	19,636	0.50	19,636
2019	277,204.74	194,043	167,829	109,376	1.50	72,917
2021	1,076,384.85	322,915	279,291	797,094	3.50	227,741
	1,442,207.68	596,714	516,102	926,106		320,294

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.9 22.21

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L2.5						
NET SALVAGE PERCENT.. 0						
2004	26,875.84	26,750	26,876			
2008	22,536.44	21,405	22,536			
2014	22,224.80	18,304	22,225			
	71,637.08	66,459	71,637			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE NET SALVAGE PERCENT.. 0						
2020	27,967.27	6,992	3,880	24,087	7.50	3,212
	27,967.27	6,992	3,880	24,087		3,212

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.5 11.48

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	22,684.22	22,117	21,948	736	0.50	736
2004	5,698.56	5,271	5,230	469	1.50	313
2007	1,760.05	1,364	1,354	406	4.50	90
	30,142.83	28,752	28,532	1,611		1,139

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.4 3.78

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	5,584,430.57	5,025,988	4,830,293	754,138	0.50	754,138
2019	9,507,270.50	6,655,089	6,395,963	3,111,308	1.50	2,074,205
2020	1,980,934.07	990,467	951,901	1,029,033	2.50	411,613
2021	504,089.49	151,227	145,339	358,750	3.50	102,500
	17,576,724.63	12,822,771	12,323,496	5,253,229		3,342,456

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.6   19.02

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SUCCESS FACTORS						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 9-2024						
NET SALVAGE PERCENT.. 0						
2019	2,803,866.07	1,784,268	1,349,479	1,454,387	2.00	727,194
	2,803,866.07	1,784,268	1,349,479	1,454,387		727,194
UNITE ERP						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 9-2034						
NET SALVAGE PERCENT.. 0						
2019	10,695,816.43	2,415,222	1,600,849	9,094,967	12.00	757,914
	10,695,816.43	2,415,222	1,600,849	9,094,967		757,914
	13,499,682.50	4,199,490	2,950,328	10,549,354		1,485,108

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.1   11.00

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2013	381,964.34	362,866	339,812	42,152	0.50	42,152
2014	988,604.39	840,314	786,926	201,678	1.50	134,452
2015	732,102.69	549,077	514,192	217,910	2.50	87,164
2016	930,430.13	604,780	566,356	364,074	3.50	104,021
2017	1,349,992.48	742,496	695,323	654,670	4.50	145,482
2018	1,384,581.24	623,062	583,477	801,105	5.50	145,655
2019	7,509,579.44	2,628,353	2,461,365	5,048,215	6.50	776,648
2020	13,110,042.00	3,277,510	3,069,278	10,040,764	7.50	1,338,769
2021	6,971,595.51	1,045,739	979,300	5,992,296	8.50	704,976
2022	13,214,700.50	660,735	618,756	12,595,944	9.50	1,325,889
	46,573,592.72	11,334,932	10,614,784	35,958,809		4,805,208

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.5   10.32

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2008	2,908,998.47	2,812,042	2,755,830	153,168	0.50	153,168
2011	425,873.07	326,504	319,977	105,896	3.50	30,256
2012	401,290.13	280,903	275,288	126,002	4.50	28,000
2013	142,364.69	90,164	88,362	54,003	5.50	9,819
2014	495,556.48	280,817	275,204	220,352	6.50	33,900
2016	1,419,264.44	615,010	602,716	816,548	8.50	96,064
2017	76,271,826.62	27,966,591	27,407,546	48,864,281	9.50	5,143,609
2018	171,914.66	51,574	50,543	121,372	10.50	11,559
2019	43,689,680.34	10,194,113	9,990,336	33,699,344	11.50	2,930,378
2021	6,526,337.79	652,634	639,588	5,886,750	13.50	436,056
2022	1,880,199.40	62,667	61,414	1,818,785	14.50	125,433
	134,333,306.09	43,333,019	42,466,804	91,866,502		8,998,242

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.2   6.70

READING SERVICE CENTER – INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES
READING SERVICE CENTER

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

INTERIM SURVIVOR CURVE.. IOWA 80-R1.5
PROBABLE RETIREMENT YEAR.. 6-2030
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1974	574,897.52	489,617	502,086	72,812	7.50	9,708
1975	7,158.54	6,079	6,234	925	7.51	123
1976	1,629.59	1,380	1,415	215	7.52	29
1977	2,106.01	1,778	1,823	283	7.52	38
1978	554.20	466	478	76	7.53	10
1979	6,707.24	5,624	5,767	940	7.54	125
1980	28,233.56	23,595	24,196	4,038	7.54	536
1981	44,870.26	37,355	38,306	6,564	7.55	869
1982	427.88	360	369	59	7.60	8
1983	1,273.20	1,069	1,096	177	7.48	24
1984	1,922.47	1,603	1,644	278	7.62	36
1985	15,545.14	12,913	13,242	2,303	7.59	303
1986	1,122.78	928	952	171	7.61	22
1987	100.24	83	85	15	7.49	2
1989	40,014.11	32,595	33,425	6,589	7.57	870
1990	23,330.17	18,886	19,367	3,963	7.59	522
1992	95,013.29	75,878	77,811	17,202	7.63	2,255
1993	1,839.65	1,465	1,502	338	7.52	45
1994	27,141.96	21,426	21,972	5,170	7.60	680
1995	4,582.00	3,591	3,682	900	7.59	119
1996	248.50	193	198	50	7.63	7
1998	683.50	522	535	148	7.55	20
2000	72,144.40	53,892	55,265	16,879	7.62	2,215
2001	73,338.56	54,241	55,622	17,717	7.57	2,340
2002	5,526.75	4,033	4,136	1,391	7.59	183
2003	201.42	145	149	52	7.60	7
2004	1,508.64	1,069	1,096	413	7.61	54
2005	4,812.03	3,352	3,437	1,375	7.63	180
2006	458.13	314	322	136	7.60	18
2007	379,291.04	254,580	261,064	118,227	7.59	15,577
2008	444,898.44	291,586	299,012	145,886	7.62	19,145
2009	14,014.85	8,968	9,196	4,819	7.60	634
2010	2,629.36	1,633	1,675	954	7.62	125
2011	3,560.30	2,141	2,196	1,364	7.62	179
2012	294.73	171	175	120	7.62	16
2014	5,428.44	2,861	2,934	2,494	7.63	327
2015	44,230.06	21,929	22,488	21,742	7.63	2,850
2016	33,847.95	15,577	15,974	17,874	7.62	2,346
2017	6,680.06	2,803	2,874	3,806	7.61	500

UGI UTILITIES, INC. - INFORMATION SERVICES
READING SERVICE CENTER

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2030						
NET SALVAGE PERCENT.. 0						
2018	41,704.28	15,501	15,896	25,808	7.61	3,391
2019	106,886.32	33,712	34,570	72,316	7.60	9,515
2021	92,336.26	15,309	15,699	76,637	7.55	10,151
	2,213,193.83	1,521,223	1,559,965	653,229		86,104

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.6   3.89

PART VIII. EXPERIENCED AND ESTIMATED NET SALVAGE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2018 TRANSACTION YEAR				
305.00		6.00-		6.00
369.00		1,147.00		1,147.00-
375.00	3,628.88	184.00-		184.00
376.00	7,446,077.98	2,023,888.00	4,146.00-	2,028,034.00-
378.00	2,639,646.78	339,196.00	216,520.00	122,676.00-
379.00	1,601,657.00			
380.00	6,753,826.12	5,717,004.00		5,717,004.00-
381.00	752,001.53	3,138.00		3,138.00-
382.00	76,914.85	328,078.00		328,078.00-
383.00	14.70	1,356,927.00		1,356,927.00-
384.00	1.19	688.00		688.00-
385.00	105,397.38	25,192.00		25,192.00-
390.10	37,749.37	705.00-		705.00
391.10	483,301.05			
391.20	67,874.16			
391.30	3,178.26			
392.00	597,553.59	189.00		189.00-
394.00	503,324.51			
395.00	4,297.81			
396.00	2,535,519.08			
397.00	328,054.14			
398.00	17,212.65	3,075.00		3,075.00-
	23,957,231.03	9,797,627.00	212,374.00	9,585,253.00-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2019 TRANSACTION YEAR				
369.00		131.00		131.00-
376.00	2,599,001.00	440,534.00	62,338.00	378,196.00-
378.00	159,150.00	154,135.00	15,813.00	138,322.00-
379.00	231,613.00			
380.00	8,211,461.00	3,425,191.00		3,425,191.00-
381.00	1,090,648.00	770.00		770.00-
382.00	72,768.00	262,633.00		262,633.00-
383.00		54,424.00-		54,424.00
384.00		2.00-		2.00
385.00		4,047.00		4,047.00-
390.10		76,973.00		76,973.00-
391.10	461,640.00			
391.20	75,179.00			
391.30	5,022.00			
391.40	3,295,776.00			
393.00	774.00			
394.00	609,662.00			
397.00	111,549.00			
398.00	76,034.00	652.00		652.00-
	17,000,277.00	4,310,640.00	78,151.00	4,232,489.00-
2020 TRANSACTION YEAR				
376.00	6,459,698.00	1,030,068.00		1,030,068.00-
378.00	2,984.00	29,723.00		29,723.00-
380.00	11,637,744.00	4,911,297.00		4,911,297.00-
381.00	904,135.00			
382.00		1,144,545.00		1,144,545.00-
383.00		2,130.00		2,130.00-
384.00		515,427.00		515,427.00-
390.10		17,949.00		17,949.00-
391.10	127,130.00			
391.20	33,245.00			
391.30	174,316.00			
392.00			691,071.00	691,071.00
394.00	808,538.00			
397.00	1,182,932.00			
398.00	54,164.00	257,300.00		257,300.00-
	21,384,886.00	7,908,439.00	691,071.00	7,217,368.00-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2021 TRANSACTION YEAR				
305.00			115,195.00	115,195.00
367.00	24.00	1,660.00		1,660.00-
369.00		3,386.00		3,386.00-
375.00	18,008.00			
376.00	4,504,366.00	2,534,160.00		2,534,160.00-
378.00		168,692.00		168,692.00-
379.00		15,105.00		15,105.00-
380.00	12,500,315.00	4,191,361.00		4,191,361.00-
381.00	3,015,928.00	1,237.00	19,201.00	17,964.00
382.00		224,823.00		224,823.00-
383.00		269.00		269.00-
384.00		13,720.00		13,720.00-
385.00		35,290.00		35,290.00-
386.00	269,143.00			
390.10	231,077.00	135.00		135.00-
391.10	661,188.00			
391.20	74,471.00			
391.30	120,424.00			
392.00			526,894.00	526,894.00
393.00	3,091.00			
394.00	869,872.00			
397.00	8,099.00			
398.00	88,752.00	391,820.00		391,820.00-
	22,364,758.00	7,581,658.00	661,290.00	6,920,368.00-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED AND ESTIMATED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2022 TRANSACTION YEAR				
376.00	6,206,044.00	2,022,087.00		2,022,087.00-
378.00	3,311,668.00	656,781.00	218,659.00	438,122.00-
380.00	6,926,792.00	3,574,917.00		3,574,917.00-
381.00	1,717,529.00	1,589.00	4,145.00	2,556.00
382.00	561,313.00	289,694.00		289,694.00-
383.00	6,349.00	3,276.00		3,276.00-
384.00	24,046.00	12,410.00		12,410.00-
390.10	657,344.00	65,735.00		65,735.00-
391.10	85,045.00			
391.20	6,467.00			
391.30	356,493.00			
391.40	4,378,298.00			
392.00	2,229,069.00		477,914.00	477,914.00
394.00	684,358.00			
397.00	82,938.00			
398.00	143,552.00			
399.00	16,032.00			
	27,393,337.00	6,626,489.00	700,718.00	5,925,771.00-
TOTAL	112,100,489.03	36,224,853.00	2,343,604.00	33,881,249.00-

BOOK VIII

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT C (HISTORIC)

2021 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF SEPTEMBER 30, 2021

Witness: John F. Wiedmayer
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 **Effective: March 29, 2022**

UGI Gas Exhibit C (Historic)
Witness: J. F. Wiedmayer

UGI UTILITIES, INC. – GAS DIVISION

DOCKET NO. R-2021-3030218

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO GAS PLANT
AT SEPTEMBER 30, 2021

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2021

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Valley Forge, Pennsylvania

Gannett Fleming

Excellence Delivered As Promised

January 6, 2022

Mr. Anton R. Hummer
Controller and Principal Accounting Officer
UGI Utilities, Inc. – Gas Division
1 UGI Drive
Denver, PA 17517

Ladies and Gentlemen:

Pursuant to your request, we have determined the annual depreciation accruals applicable to gas plant at September 30, 2021 for the consolidated UGI gas company. Summaries of the original cost, annual accruals and the book depreciation reserve are presented in Tables 1 and 2 of the attached report.

A description of the methods and procedures upon which the study was based is set forth in a companion report, UGI Gas Exhibit C (Future), "Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant at September 30, 2022".

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

John F. Wiedmayer

JOHN F. WIEDMAYER, C.D.P.
Project Manager, Depreciation Studies

JFW:mle

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TABLE OF CONTENTS

PART I. INTRODUCTION

UGI UTILITIES, INC. – GAS DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for UGI Utilities, Inc. – Gas Division to determine the annual depreciation accrual rates and amounts for ratemaking purposes applicable to the original cost of gas plant at September 30, 2021.

BASIS OF STUDY

Depreciation

The annual depreciation accruals and accrued depreciation were calculated using the straight line method, the remaining life basis, the average service life (ASL) procedure for plant installed prior to 1982 and the equal life group procedure (ELG) for 1982 and subsequent vintages. The calculations were based on the attained ages and estimated service life characteristics for each depreciable group of gas property.

Service Life Estimates

The service life and survivor curve estimates used for the calculation of depreciation at September 30, 2021, are set forth in Table 1 and are based on data through 2017 for the consolidated UGI gas company. The service life estimates are the same estimates as submitted to the Pennsylvania Public Utility Commission (PA PUC) in the most recent service life study report in January 2019 as part of the gas base rate case filing.

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals at September 30, 2021, the book reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation for the average service life procedure are presented in Exhibit C (Future). The detailed calculations at September 30, 2021, are set forth in Part III of this report.

Amortization of Net Salvage

In accordance with Pennsylvania rate regulation practice, under which experienced costs of negative net salvage are amortized after their occurrence, no adjustments for expected net salvage were made to either the annual depreciation accrual or the calculated accrued depreciation for the individual accounts. The annual provision for recovering negative net salvage is based on the amortization of experienced net salvage over a five-year period.

PART II. RESULTS OF STUDY

PART II. RESULTS OF STUDY

DESCRIPTION OF SUMMARY TABULATIONS

Tables 1 and 2 presented on pages II-3 through II-7 summarize the results of the depreciation study as of September 30, 2021 for the consolidated UGI gas company. Table 1 sets forth, by depreciable group, the estimated survivor curve, original cost, book depreciation reserve as of September 30, 2021, future book accruals, and calculated annual accrual amount and rate. Table 2 presents the annual amortization of experienced net salvage based on the period 2017 through 2021.

DETAILED TABULATIONS OF DEPRECIATION CALCULATIONS

Supporting data for the original cost depreciation calculations in account sequence are presented in Part III of this report. The tables indicate the estimated survivor curves used in the calculations and set forth, for each installation year, the original cost, calculated accrued depreciation, allocated book reserve, future book accruals, remaining life, and calculated remaining life accrual.

Detailed tabulations setting forth the experienced cost of removal and salvage amounts by year and account are presented in Part IV of this report. The net salvage amounts are carried forward to Table 2 which presents the five-year amortization.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2021

	ACCOUNT	PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
GAS PLANT								
PRODUCTION PLANT								
305	MANUFACTURED GAS PLANT SITE REMEDIATION		FULLY ACCRUED*	0	100,374	(100,374)	-	0
325.2	PRODUCING LEASEHOLDS		55 - S0.5	163,100	162,069	1,031	0.02	35
325.4	RIGHTS-OF-WAY		60 - R1	30,277	29,681	596	0.06	19
328	FIELD MEASURING AND REGULATING STATION STRUCTURES		FULLY ACCRUED	1,263	1,263	0	-	0
329	OTHER STRUCTURES		FULLY ACCRUED	44,785	44,783	2	-	0
330	PRODUCING GAS WELLS - WELL CONSTRUCTION		FULLY ACCRUED	18,209	18,209	0	-	0
331	PRODUCING GAS WELLS - WELL EQUIPMENT		FULLY ACCRUED	24,441	24,441	0	-	0
332	FIELD LINES		47 - L0	750,689	724,840	25,849	0.13	1,004
334	FIELD MEASURING AND REGULATING STATION EQUIPMENT		24 - O3	89,725	84,547	5,178	0.47	423
335	DRILLING AND CLEANING EQUIPMENT		30 - S0.5	49,604	49,463	141	0.04	19
337	OTHER EQUIPMENT		FULLY ACCRUED	11,062	11,062	0	-	0
TOTAL PRODUCTION PLANT				**1,183,155**	**1,250,732**	**(67,577)**	**0.13**	**1,500**
STORAGE PLANT								
352.01	WELL CONSTRUCTION		FULLY ACCRUED*	0	(51,904)	51,904	-	0
TOTAL STORAGE PLANT				**0**	**(51,904)**	**51,904**	-	**0**
TRANSMISSION PLANT								
365.2	RIGHTS-OF-WAY		70 - R4	868,160	525,023	343,137	1.36	11,836
366	STRUCTURES AND IMPROVEMENTS		30 - R1	162,216	145,020	17,196	0.81	1,309
367	MAINS		70 - R3	39,074,497	21,426,794	17,647,703	1.18	459,561
369	MEASURING AND REGULATING STATION EQUIPMENT		49 - R2	6,152,338	3,870,923	2,281,415	1.53	93,982
370	COMMUNICATION EQUIPMENT		23 - R0.5	3,486,136	2,030,369	1,455,767	3.16	110,294
371	OTHER EQUIPMENT		35 - R2.5	140,637	128,356	12,281	0.86	1,216
371.1	TESTING EQUIPMENT		20 - R3	210,011	147,396	62,615	2.46	5,169
TOTAL TRANSMISSION PLANT				**50,093,995**	**28,273,881**	**21,820,114**	**1.36**	**683,367**
DISTRIBUTION PLANT								
374.2	RIGHTS-OF-WAY		75 - R3	3,544,569	1,334,545	2,210,024	1.31	46,269
375	STRUCTURES AND IMPROVEMENTS		50 - S0.5	5,554,376	3,158,924	2,395,452	1.62	89,958
376.1	MAINS - PRIMARILY STEEL		73 - R2.5	637,160,499	175,899,219	461,261,280	1.55	9,880,281
376.2	MAINS - CAST IRON	09-2027	65 - R1	2,188,512	268,125	1,920,387	16.77	366,951
376.3	MAINS - PLASTIC		67 - R3	1,287,145,663	274,291,463	1,012,854,200	1.63	21,004,152
376.5	MAINS - PRIMARILY WROUGHT IRON	09-2041	70 - R1	305,458	276,113	29,345	0.94	2,863
376.7	REG AFUDC		5 - SQ	1,322,088	134,963	1,187,125	19.95	263,806
378	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL		47 - S0	118,827,801	26,330,599	92,497,202	2.83	3,363,066
379	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		45 - R2	25,635,909	7,762,976	17,872,933	2.51	643,119
380	SERVICES		46 - S1	1,321,300,624	367,843,768	953,456,856	2.51	33,169,118
381	METERS		35 - R2	143,350,208	52,248,571	91,101,637	3.16	4,532,034
381.1	METERS - ERTS		17 - S3	23,249,326	18,643,419	4,605,907	3.11	722,009
382	METER INSTALLATIONS		46 - S1	98,342,272	33,970,679	64,371,593	2.40	2,364,599
383	HOUSE REGULATORS		46 - S1	10,606,160	5,524,689	5,081,471	2.04	216,441
384	HOUSE REGULATOR INSTALLATIONS		46 - S1	18,501,668	8,437,825	10,063,843	2.09	386,239
385	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		45 - R2	39,907,546	16,636,654	23,270,892	2.16	862,083
386.0	OTHER PROPERTY ON CUSTOMERS PREMISES		46 - S1	68,824	(104,269)	173,093	14.63	10,069
386.1	OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS		45 - R2	953,218	648,577	304,641	1.60	15,228
386.2	OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS		25 - R3	24,705	24,720	(15)	-	0
387	OTHER EQUIPMENT		35 - R2.5	4,871,243	2,825,275	2,045,968	2.17	105,502
387.1	OTHER EQUIPMENT - GRAPHIC DATA BASE		25 - SQ	1,490,664	1,464,426	26,238	0.30	4,400
TOTAL DISTRIBUTION PLANT				**3,744,351,333**	**997,621,261**	**2,746,730,072**	**2.08**	**78,048,187**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2021

ACCOUNT		PROBABLE RETIREMENT YEAR	SURVIVOR CURVE	ORIGINAL COST	BOOK RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL RATE	CALCULATED ANNUAL ACCRUAL AMOUNT
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
GENERAL PLANT								
390.1	STRUCTURES AND IMPROVEMENTS		VARIOUS**	105,260,872	39,865,784	65,395,089	2.78	2,930,792
391.1	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,461,586	800,633	3,660,953	6.33	282,399
391.2	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		10 - SQ	200,101	35,807	164,294	9.59	19,183
391.3	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT		5 - SQ	1,019,470	653,878	365,592	20.68	210,800
391.4	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE		10 - SQ	4,378,298	4,336,112	42,186	-	0
392.1	TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S		8 - L2.5	2,708,878	666,930	2,041,948	13.67	370,326
392.2	TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS		10 - L2.5	21,267,604	5,971,127	15,296,477	10.91	2,319,566
392.3	TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLE		12 - L3	2,642,994	882,856	1,760,138	8.42	222,619
392.4	TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS		12 - L3	4,066,668	1,315,349	2,751,319	8.24	335,152
392.5	TRANSPORTATION EQUIPMENT - TRAILERS		15 - L2	1,931,903	644,625	1,287,278	6.93	133,895
393	STORES EQUIPMENT		20 - SQ	17,606	5,453	12,153	4.96	874
394	TOOLS, SHOP AND GARAGE EQUIPMENT		20 - SQ	33,689,953	11,576,680	22,113,273	5.45	1,834,660
395	LABORATORY EQUIPMENT		20 - SQ	437,779	90,041	347,738	5.05	22,099
396	POWER OPERATED EQUIPMENT		15 - L2	6,570,611	1,924,973	4,645,638	7.49	492,312
397	COMMUNICATION EQUIPMENT		10 - SQ	1,021,736	373,200	648,536	11.23	114,753
398	MISCELLANEOUS EQUIPMENT		15 - SQ	2,355,656	649,081	1,706,575	10.40	244,947
399	OTHER TANGIBLE PROPERTY		5 - SQ	16,032	16,032	0	-	0
TOTAL GENERAL PLANT				**192,047,747**	**69,808,561**	**122,239,187**	**4.96**	**9,534,377**
TOTAL DEPRECIABLE GAS PLANT				**3,987,676,230**	**1,096,902,531**	**2,890,773,700**	**2.21**	**88,267,431**
NONDEPRECIABLE PLANT								
301	ORGANIZATION			166,478				
302	FRANCHISES AND CONSENTS			193,597				
303	MISCELLANEOUS INTANGIBLE PLANT			289,868				
304.1	LAND AND LAND RIGHTS - LAND			375,198				
304.2	LAND AND LAND RIGHTS - LAND RIGHTS			6,454				
325.1	PRODUCING LANDS			13,029				
325.5	OTHER LAND			1,134				
365.1	LAND			47,323				
374.1	LAND AND LAND RIGHTS - LAND			849,347				
374.2	LAND AND LAND RIGHTS - LAND RIGHTS			7,305,824				
389.1	LAND AND LAND RIGHTS - LAND			10,369,472				
389.2	LAND AND LAND RIGHTS - LAND RIGHTS			1,313				
TOTAL NONDEPRECIABLE PLANT				**19,619,037**				
TOTAL GAS PLANT				**4,007,295,267**				

UGI UTILITIES, INC. - GAS DIVISION

TABLE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND
CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT SEPTEMBER 30, 2021

ACCOUNT (1)		PROBABLE RETIREMENT YEAR (2)	SURVIVOR CURVE (3)	ORIGINAL COST (4)	BOOK RESERVE (5)	FUTURE BOOK ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL RATE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)
OTHER UTILITY PLANT								
COMMON PLANT								
301	ORGANIZATION (NONDEPRECIABLE)			138,964				
389.1	LAND AND LAND RIGHTS - LAND (NONDEPRECIABLE)			6,947,108				
390.1	STRUCTURES AND IMPROVEMENTS	01-2069	70 - R1	32,616,586	1,929,837	30,686,749	3.01	980,228
390.2	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY				10,628	(10,628)	-	0
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	4,367,824	780,636	3,587,188	5.35	233,486
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	1,493,560	213,695	1,279,865	24.10	359,879
392.1	TRANSPORTATION EQUIPMENT - CARS		7 - L2.5	71,637	71,637	0	-	0
398	MISCELLANEOUS EQUIPMENT		10 - SQ	27,967	669	27,298	11.48	3,212
TOTAL COMMON PLANT				**45,663,646**	**3,007,102**	**35,570,472**	**4.09**	**1,576,805**
TOTAL COMMON PLANT ALLOCATED TO GAS DIVISIONS - 88.97%				**40,626,946**	**2,675,419**	**31,647,049**		**1,402,883**
INFORMATION SERVICES (IS)								
391	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		20 - SQ	36,837	33,595	3,242	4.87	1,793
391.1	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		5 - SQ	21,905,364	12,938,845	8,966,519	18.81	4,120,085
391.2	OFFICE FURNITURE AND EQUIPMENT - SOFTWARE		SQUARE	13,499,682	1,464,953	12,034,729	11.00	1,485,089
391.3	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YEARS		10 - SQ	45,912,815	18,682,455	27,230,360	8.57	3,934,215
391.4	OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 15 YEARS		15 - SQ	138,024,446	39,050,337	98,974,109	6.60	9,108,232
TOTAL INFORMATION SERVICES				**219,379,144**	**72,170,185**	**147,208,959**	**8.50**	**18,649,414**
TOTAL INFORMATION SERVICES ALLOCATED TO ALL GAS DIVISIONS - 91.68%				**201,126,799**	**66,165,626**	**134,961,174**		**17,097,783**
READING SERVICE CENTER								
390.1	STRUCTURES AND IMPROVEMENTS	06-2030	80 - R1.5	2,213,194	1,472,986	740,208	3.93	86,870
LESS READING SERVICE CENTER ALLOCATED TO ELECTRIC DIVISION - 9.31%				**206,048**	**137,135**	**68,913**		**8,088**
EMPIRE YARD BUILDING								
390.1	STRUCTURES AND IMPROVEMENTS	12-2047	80 - R1.5	13,889,132	8,071,066	5,818,066	4.18	245,841
LESS EMPIRE BUILDING ALLOCATED TO ELECTRIC DIVISION - 13.07%				**1,815,310**	**1,054,888**	**760,421**		**32,131**
TOTAL OTHER UTILITY PLANT ALLOCATED TO ALL GAS DIVISIONS				**239,732,387**	**67,649,022**	**165,778,889**		**18,460,447**
TOTAL PLANT IN SERVICE				**4,247,027,654**	**1,164,551,553**	**3,056,552,589**		**106,727,878**
AMORTIZATION OF NEGATIVE NET SALVAGE								*8,006,504*
GRAND TOTAL				**4,247,027,654**	**1,164,551,553**	**3,056,552,589**		**114,734,382**

* ACCOUNTS 305 AND 352.01 HAVE NO REMAINING DEPRECIATION ACCRUALS. THE FUTURE ACCRUALS SHOWN ARE RELATED TO THE AMORTIZATION OF NEGATIVE NET SALVAGE.
** SURVIVOR CURVES FOR ACCOUNT 390.1 ARE INTERIM SURVIVOR CURVES.INDIVIDUAL BUILDINGS ARE LIFE SPANNED.

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. AMORTIZATION OF EXPERIENCED NET SALVAGE

	2017		2018		2019		2020		2021		FIVE YEAR	NET
ACCOUNT	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	NET SALVAGE TOTAL	SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GAS PLANT												
PRODUCTION PLANT												
305	0	74,121	0	(6)	0	0	0	0	(115,195)	0	(41,080)	(8,216)
325.2	0	0	0	0	0	0	0	0	0	0	0	0
325.4	0	0	0	0	0	0	0	0	0	0	0	0
328	0	0	0	0	0	0	0	0	0	0	0	0
329	0	0	0	0	0	0	0	0	0	0	0	0
330	0	0	0	0	0	0	0	0	0	0	0	0
331	0	0	0	0	0	0	0	0	0	0	0	0
332	0	0	0	0	0	0	0	0	0	0	0	0
334	0	2	0	0	0	0	0	0	0	0	2	0
335	0	0	0	0	0	0	0	0	0	0	0	0
337	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**74,123**	**0**	**(6)**	**0**	**0**	**0**	**0**	**(115,195)**	**0**	**(41,078)**	**(8,216)**
STORAGE PLANT												
352.01	0	79,852	0	0	0	0	0	0	0	0	79,852	15,970
TOTAL	**0**	**79,852**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**79,852**	**15,970**
TRANSMISSION PLANT												
365.2	0	0	0	0	0	0	0	0	0	0	0	0
366	0	0	0	0	0	0	0	0	0	0	0	0
367	0	0	0	0	0	0	0	0	0	1,660	1,660	332
369	0	0	0	1,147	0	131	0	0	0	3,386	4,664	933
370	0	0	0	0	0	0	0	0	0	0	0	0
371	0	0	0	0	0	0	0	0	0	0	0	0
371.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**1,147**	**0**	**131**	**0**	**0**	**0**	**5,046**	**6,324**	**1,265**
DISTRIBUTION PLANT												
374.2	0	0	0	0	0	0	0	0	0	0	0	0
375	0	35,280	0	(184)	0	0	0	0	0	0	35,096	7,019
376.1	9,141	1,068,995	4,146	1,112,569	(23,558)	527,144	0	422,998	0	1,712,927	4,834,362	966,872
376.2	0	361,280	0	545,838	(16,292)	(284,507)	0	529,595	0	92,247	1,228,161	248,891
376.3	0	347,808	0	365,481	0	197,897	0	77,475	0	728,986	1,717,647	343,529
376.5	0	0	0	0	0	0	0	0	0	0	0	0
376.7	0	0	0	0	0	0	0	0	0	0	0	0
378	(59,792)	287,084	(216,520)	339,196	(38,301)	154,135	0	29,723	0	168,692	664,217	129,585
379	0	0	0	0	0	0	0	0	0	15,105	15,105	3,021
380	0	5,711,858	0	5,717,004	0	3,425,191	0	4,911,297	0	4,191,361	23,956,711	4,791,342
381	0	2,218	0	3,138	0	770	0	0	(19,201)	1,237	(11,838)	(2,368)
381.1	0	0	0	0	0	0	0	0	0	0	0	0
382	0	581,870	0	328,078	0	262,633	0	1,144,545	0	224,823	2,541,949	508,390
383	0	3,530,065	0	1,356,927	0	(54,424)	0	2,130	0	269	4,834,967	966,993
384	0	1,442	0	688	0	(2)	0	515,427	0	13,720	531,275	106,255
385	0	11,977	0	25,192	0	4,047	0	0	0	35,290	76,506	15,301
386.0	0	0	0	0	0	0	0	0	0	0	0	0
386.1	0	0	0	0	0	0	0	0	0	0	0	0
386.2	0	0	0	0	0	0	0	0	0	0	0	0
386.3	0	0	0	0	0	0	0	0	0	0	0	0
387	0	7,552	0	0	0	0	0	0	0	0	7,552	1,510
387.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**(50,651)**	**11,947,429**	**(212,374)**	**9,793,927**	**(78,151)**	**4,232,884**	**0**	**7,633,190**	**(19,201)**	**7,184,657**	**40,431,710**	**8,086,340**

UGI UTILITIES, INC. - GAS DIVISION

TABLE 2. AMORTIZATION OF EXPERIENCED NET SALVAGE

	2017		2018		2019		2020		2021		FIVE YEAR	NET
ACCOUNT	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	NET SALVAGE TOTAL	SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=(12)/5
GENERAL PLANT												
390.1	0	78,311	0	(705)	0	76,973	0	17,949	0	135	172,663	34,533
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
392.1	(2,951)	228	0	7	0	0	(30,492)	0	0	0	(33,208)	(6,642)
392.2	(43,651)	3,374	0	101	0	0	(449,978)	0	(526,894)	0	(1,017,048)	(203,409)
392.3	(18,315)	1,416	0	42	0	0	(64,698)	0	0	0	(81,555)	(16,312)
392.4	(15,974)	1,235	0	37	0	0	(18,471)	0	0	0	(33,174)	(6,635)
392.5	(1,119)	87	0	3	0	0	(127,432)	0	0	0	(128,461)	(25,692)
393	0	0	0	0	0	0	0	0	0	0	0	0
394	0	0	0	0	0	0	0	0	0	0	0	0
395	0	0	0	0	0	0	0	0	0	0	0	0
396	(3,100)	663	0	0	0	0	0	0	0	0	(2,437)	(487)
397	0	0	0	0	0	0	0	0	0	0	0	0
398	0	26,099	0	3,075	0	652	0	257,300	0	391,820	678,946	135,789
TOTAL	**(85,110)**	**111,413**	**0**	**2,559**	**0**	**77,625**	**(691,071)**	**275,249**	**(526,894)**	**391,955**	**(444,274)**	**(88,855)**
TOTAL GAS PLANT	**(135,761)**	**12,212,817**	**(212,374)**	**9,797,627**	**(78,151)**	**4,310,640**	**(691,071)**	**7,908,439**	**(661,290)**	**7,581,658**	**40,032,534**	**8,006,504**
OTHER UTILITY PLANT												
COMMON PLANT												
390.1	0	0	0	0	0	0	0	0	0	0	0	0
390.2	0	0	0	0	0	0	0	0	0	0	0	0
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
392.1	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
INFORMATION SERVICES												
391	0	0	0	0	0	0	0	0	0	0	0	0
391.1	0	0	0	0	0	0	0	0	0	0	0	0
391.2	0	0	0	0	0	0	0	0	0	0	0	0
391.3	0	0	0	0	0	0	0	0	0	0	0	0
391.4	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
GRAND TOTAL	**(135,761)**	**12,212,817**	**(212,374)**	**9,797,627**	**(78,151)**	**4,310,640**	**(691,071)**	**7,908,439**	**(661,290)**	**7,581,658**	**40,032,534**	**8,006,504**

* COLUMN (12) EQUALS THE SUMMATION OF COLUMNS (2) THROUGH (11).

PART III. DETAILED DEPRECIATION CALCULATIONS

CUMULATIVE DEPRECIATED ORIGINAL COST

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1849	2,795	2,795			0.0
1857	341	341			0.0
1858	2	2			0.0
1859	148	148			0.0
1862	16	16			0.0
1866	31	31			0.0
1867	90	90			0.0
1868	5	5			0.0
1869	14	14			0.0
1871	2,385	2,385			0.0
1872	116	116			0.0
1873	27	27			0.0
1874	82	82			0.0
1875	395	395			0.0
1876	10,428	10,428			0.0
1878	16	16			0.0
1879	911	911			0.0
1880	229	229			0.0
1881	1,431	1,431			0.0
1882	167	167			0.0
1883	79	79			0.0
1884	970	970			0.0
1885	118	118			0.0
1886	550	550			0.0
1887	1,182	1,182			0.0
1888	4,580	4,580			0.0
1889	1,421	1,421			0.0
1890	1,929	1,929			0.0
1891	1,108	125	983	983	0.0
1892	1,496	1,496		983	0.0
1893	348	239	109	1,092	0.0
1894	2,856	2,678	178	1,270	0.0
1895	2,154	413	1,741	3,011	0.0
1896	1,875	438	1,437	4,448	0.0
1897	5,144	4,104	1,040	5,488	0.0
1898	21,488	20,952	536	6,024	0.0
1899	31,164	11,752	19,412	25,436	0.0
1901	86,902	80,586	6,316	31,752	0.0
1902	20,291	17,480	2,811	34,563	0.0
1903	55,110	49,763	5,347	39,910	0.0
1904	74,347	70,642	3,705	43,615	0.0
1905	60,038	55,508	4,530	48,145	0.0
1906	24,713	18,380	6,333	54,478	0.0
1907	32,852	28,225	4,627	59,105	0.0
1908	54,871	42,758	12,113	71,218	0.0
1909	29,901	24,305	5,596	76,814	0.0

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1910	34,895	22,905	11,990	88,804	0.0
1911	62,100	50,412	11,688	100,492	0.0
1912	50,486	33,061	17,425	117,917	0.0
1913	67,407	63,427	3,980	121,897	0.0
1914	73,947	62,370	11,577	133,474	0.0
1915	62,212	43,220	18,992	152,466	0.0
1916	45,835	31,559	14,276	166,742	0.0
1917	34,230	26,226	8,004	174,746	0.0
1918	31,963	23,972	7,991	182,737	0.0
1919	55,643	33,800	21,843	204,580	0.0
1920	70,553	48,683	21,870	226,450	0.0
1921	118,389	87,026	31,363	257,813	0.0
1922	138,638	85,160	53,478	311,291	0.0
1923	138,273	98,309	39,964	351,255	0.0
1924	456,911	334,926	121,985	473,240	0.0
1925	177,119	131,612	45,507	518,747	0.0
1926	468,959	374,150	94,809	613,556	0.0
1927	246,081	192,999	53,082	666,638	0.0
1928	320,161	271,298	48,863	715,501	0.0
1929	305,321	232,024	73,297	788,798	0.0
1930	554,621	467,773	86,848	875,646	0.0
1931	507,127	428,342	78,785	954,431	0.0
1932	145,566	134,500	11,066	965,497	0.0
1933	168,724	164,139	4,585	970,082	0.0
1934	47,577	43,850	3,727	973,809	0.0
1935	55,325	48,748	6,577	980,386	0.0
1936	60,734	47,666	13,068	993,454	0.0
1937	65,048	58,737	6,311	999,765	0.0
1938	47,027	41,690	5,337	1,005,102	0.0
1939	74,686	58,947	15,739	1,020,841	0.0
1940	99,049	85,026	14,023	1,034,864	0.0
1941	185,961	161,342	24,619	1,059,483	0.0
1942	85,332	78,084	7,248	1,066,731	0.0
1943	33,978	31,055	2,923	1,069,654	0.0
1944	49,080	43,588	5,492	1,075,146	0.0
1945	54,002	50,230	3,772	1,078,918	0.0
1946	533,711	435,277	98,434	1,177,352	0.0
1947	206,553	169,642	36,911	1,214,263	0.0
1948	287,405	225,163	62,242	1,276,505	0.0
1949	671,578	588,708	82,870	1,359,375	0.0
1950	2,327,366	1,887,883	439,483	1,798,858	0.1
1951	721,616	573,651	147,965	1,946,823	0.1
1952	1,871,784	1,530,884	340,900	2,287,723	0.1
1953	1,583,390	1,155,604	427,786	2,715,509	0.1
1954	2,309,264	1,871,743	437,521	3,153,030	0.1
1955	3,265,367	2,723,913	541,454	3,694,484	0.1

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1956	3,090,114	2,269,604	820,510	4,514,994	0.2
1957	5,391,908	4,085,509	1,306,399	5,821,393	0.2
1958	4,158,327	3,095,117	1,063,210	6,884,603	0.2
1959	4,064,503	2,908,221	1,156,282	8,040,885	0.3
1960	5,268,436	3,935,683	1,332,753	9,373,638	0.3
1961	5,480,328	4,121,953	1,358,375	10,732,013	0.4
1962	4,496,506	3,226,215	1,270,291	12,002,304	0.4
1963	6,131,077	4,297,934	1,833,143	13,835,447	0.5
1964	7,510,195	5,115,678	2,394,517	16,229,964	0.6
1965	9,506,777	6,622,723	2,884,054	19,114,018	0.7
1966	9,214,871	6,452,060	2,762,811	21,876,829	0.8
1967	9,404,914	6,545,561	2,859,353	24,736,182	0.9
1968	11,090,061	7,433,581	3,656,480	28,392,662	1.0
1969	11,672,912	7,773,394	3,899,518	32,292,180	1.1
1970	10,688,205	7,160,586	3,527,619	35,819,799	1.2
1971	10,103,471	6,696,760	3,406,711	39,226,510	1.4
1972	11,038,301	7,048,401	3,989,900	43,216,410	1.5
1973	10,121,943	6,701,867	3,420,076	46,636,486	1.6
1974	10,705,879	7,313,726	3,392,153	50,028,639	1.7
1975	9,137,088	6,008,063	3,129,025	53,157,664	1.8
1976	8,767,556	5,723,699	3,043,857	56,201,521	1.9
1977	11,040,132	7,008,736	4,031,396	60,232,917	2.1
1978	10,464,712	6,479,961	3,984,751	64,217,668	2.2
1979	15,636,040	9,473,317	6,162,723	70,380,391	2.4
1980	27,832,782	16,881,827	10,950,955	81,331,346	2.8
1981	27,467,824	16,235,139	11,232,685	92,564,031	3.2
1982	27,153,048	17,153,353	9,999,695	102,563,726	3.5
1983	14,470,638	9,414,317	5,056,321	107,620,047	3.7
1984	18,934,047	12,042,690	6,891,357	114,511,404	4.0
1985	23,040,677	14,597,430	8,443,247	122,954,651	4.3
1986	27,694,018	16,980,794	10,713,224	133,667,875	4.6
1987	31,671,101	19,350,421	12,320,680	145,988,555	5.1
1988	42,353,293	24,845,667	17,507,626	163,496,181	5.7
1989	47,385,552	27,599,685	19,785,867	183,282,048	6.3
1990	50,179,900	28,732,183	21,447,717	204,729,765	7.1
1991	38,919,230	22,119,004	16,800,226	221,529,991	7.7
1992	44,855,102	25,542,682	19,312,420	240,842,411	8.3
1993	33,346,793	18,538,600	14,808,193	255,650,604	8.8
1994	50,939,632	28,083,712	22,855,920	278,506,524	9.6
1995	59,969,823	30,096,602	29,873,221	308,379,745	10.7
1996	62,842,298	29,983,353	32,858,945	341,238,690	11.8
1997	74,592,675	35,018,206	39,574,469	380,813,159	13.2
1998	60,598,489	28,087,204	32,511,285	413,324,444	14.3
1999	47,882,498	21,936,307	25,946,191	439,270,635	15.2
2000	61,312,583	26,046,311	35,266,272	474,536,907	16.4
2001	61,679,674	26,363,962	35,315,712	509,852,619	17.6

UGI UTILITIES, INC. - GAS DIVISION

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	DEPRECIATED ORIGINAL COST CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2002	58,676,038	25,133,292	33,542,746	543,395,365	18.8
2003	58,579,200	23,265,504	35,313,696	578,709,061	20.0
2004	77,197,779	31,167,840	46,029,939	624,739,000	21.6
2005	68,735,241	25,272,876	43,462,365	668,201,365	23.1
2006	65,778,373	25,422,105	40,356,268	708,557,633	24.5
2007	65,501,465	22,497,814	43,003,651	751,561,284	26.0
2008	69,123,569	21,722,096	47,401,473	798,962,757	27.6
2009	69,942,207	22,862,720	47,079,487	846,042,244	29.3
2010	61,487,267	17,041,901	44,445,366	890,487,610	30.8
2011	86,761,281	21,466,288	65,294,993	955,782,603	33.1
2012	104,862,158	23,157,307	81,704,851	1,037,487,454	35.9
2013	124,305,653	24,357,221	99,948,432	1,137,435,886	39.3
2014	157,427,240	26,787,533	130,639,707	1,268,075,593	43.9
2015	183,282,401	27,592,372	155,690,029	1,423,765,622	49.3
2016	204,613,786	26,429,809	178,183,977	1,601,949,599	55.4
2017	205,055,112	21,633,597	183,421,515	1,785,371,114	61.8
2018	298,089,400	25,409,474	272,679,926	2,058,051,040	71.2
2019	274,645,343	18,741,206	255,904,137	2,313,955,177	80.0
2020	280,200,717	13,382,864	266,817,853	2,580,773,030	89.3
2021	314,597,952	4,567,688	310,030,264	2,890,803,294	100.0
TOTAL	3,987,676,225	1,096,872,931	2,890,803,294		

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2003	7,183	5,587	1,596	1,596	0.0
2004	38,772	35,629	3,143	4,739	0.0
2005	39,966	27,725	12,241	16,980	0.0
2006	2,469	1,609	860	17,840	0.1
2007	878	536	342	18,182	0.1
2008	23,109	22,861	248	18,430	0.1
2009	4,753	2,498	2,255	20,685	0.1
2010	747,319	361,325	385,994	406,679	1.1
2014	22,225	22,225		406,679	1.1
2017	51,353	27,861	23,492	430,171	1.2
2018	88,618	37,395	51,223	481,394	1.4
2019	33,840,603	2,298,112	31,542,491	32,023,885	90.0
2020	1,962,770	77,909	1,884,861	33,908,746	95.3
2021	1,747,559	75,202	1,672,357	35,581,103	100.0
TOTAL	38,577,577	2,996,474	35,581,103		

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

			DEPRECIATED ORIGINAL COST		
YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
2000	802,206	802,206			0.0
2001	18,800	18,800			0.0
2002	454,353	454,152	201	201	0.0
2003	22,684	20,873	1,811	2,012	0.0
2004	1,408,963	1,408,225	738	2,750	0.0
2005	990,669	990,669		2,750	0.0
2006	4,077,548	4,077,548		2,750	0.0
2007	6,303,993	6,134,444	169,549	172,299	0.1
2008	3,168,505	2,817,392	351,113	523,412	0.4
2009	481,827	481,827		523,412	0.4
2010	324,586	324,586		523,412	0.4
2011	450,138	315,520	134,618	658,030	0.4
2012	3,393,988	2,795,331	598,657	1,256,687	0.9
2013	524,329	369,683	154,646	1,411,333	1.0
2014	1,484,161	906,328	577,833	1,989,166	1.4
2015	732,103	426,317	305,786	2,294,952	1.6
2016	2,349,695	966,885	1,382,810	3,677,762	2.5
2017	81,950,458	26,717,302	55,233,156	58,910,918	40.0
2018	7,140,926	4,304,166	2,836,760	61,747,678	41.9
2019	74,206,213	14,919,604	59,286,609	121,034,287	82.2
2020	15,090,976	2,344,123	12,746,853	133,781,140	90.9
2021	14,002,023	574,204	13,427,819	147,208,959	100.0
TOTAL	219,379,144	72,170,185	147,208,959		

READING SERVICE CENTER – INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES
READING SERVICE CENTER

CUMULATIVE DEPRECIATED ORIGINAL COST BY YEAR INSTALLED
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR INST (1)	ORIGINAL COST (2)	ACCRUED DEPRECIATION (3)	DEPRECIATED ORIGINAL COST AMOUNT (2) - (3) (4)	CUMULATIVE AMOUNT (5)	PCT OF COL 4 TOTAL (6)
1974	574,898	492,508	82,390	82,390	11.1
1975	7,159	6,113	1,046	83,436	11.3
1976	1,630	1,386	244	83,680	11.3
1977	2,106	1,785	321	84,001	11.3
1978	554	468	86	84,087	11.4
1979	6,707	5,645	1,062	85,149	11.5
1980	28,234	23,662	4,572	89,721	12.1
1981	44,870	37,442	7,428	97,149	13.1
1982	428	363	65	97,214	13.1
1983	1,273	1,072	201	97,415	13.2
1984	1,922	1,612	310	97,725	13.2
1985	15,545	12,981	2,564	100,289	13.5
1986	1,123	932	191	100,480	13.6
1987	100	82	18	100,498	13.6
1989	40,014	32,511	7,503	108,001	14.6
1990	23,330	18,819	4,511	112,512	15.2
1992	95,013	75,733	19,280	131,792	17.8
1993	1,840	1,455	385	132,177	17.9
1994	27,142	21,263	5,879	138,056	18.7
1995	4,582	3,558	1,024	139,080	18.8
1996	248	191	57	139,137	18.8
1998	684	515	169	139,306	18.8
2000	72,144	53,120	19,024	158,330	21.4
2001	73,339	53,184	20,155	178,485	24.1
2002	5,527	3,946	1,581	180,066	24.3
2003	201	141	60	180,126	24.3
2004	1,509	1,043	466	180,592	24.4
2005	4,812	3,258	1,554	182,146	24.6
2006	458	303	155	182,301	24.6
2007	379,291	244,870	134,421	316,722	42.8
2008	444,898	279,815	165,083	481,805	65.1
2009	14,015	8,539	5,476	487,281	65.8
2010	2,629	1,549	1,080	488,361	66.0
2011	3,560	2,015	1,545	489,906	66.2
2012	295	159	136	490,042	66.2
2014	5,428	2,604	2,824	492,866	66.6
2015	44,230	19,603	24,627	517,493	69.9
2016	33,848	13,610	20,238	537,731	72.6
2017	6,680	2,368	4,312	542,043	73.2
2018	41,704	12,459	29,245	571,288	77.2
2019	106,886	24,930	81,956	653,244	88.3
2021	92,336	5,374	86,962	740,206	100.0
TOTAL	2,213,192	1,472,986	740,206		

UTILITY PLANT IN SERVICE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.2 PRODUCING LEASEHOLDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 55-S0.5						
NET SALVAGE PERCENT.. 0						
1892	1,496.50	1,496	1,497			
1894	2,650.57	2,651	2,651			
1897	3,621.53	3,622	3,622			
1898	13,387.22	13,387	13,387			
1899	1,044.85	1,045	1,045			
1901	748.25	748	748			
1902	4,491.26	4,491	4,491			
1904	8,221.11	8,221	8,221			
1905	43,088.40	43,088	43,088			
1906	1,680.87	1,681	1,681			
1907	471.47	471	471			
1908	75.00	75	75			
1909	1,941.30	1,941	1,941			
1911	526.00	526	526			
1912	2,693.57	2,681	2,694			
1913	31,916.65	31,592	31,917			
1914	1,141.85	1,123	1,142			
1917	1,200.00	1,157	1,200			
1918	701.79	672	702			
1919	1,973.32	1,879	1,973			
1921	2,993.63	2,813	2,994			
1923	1.00	1	1			
1926	4,047.55	3,680	4,048			
1928	1,435.71	1,288	1,436			
1929	962.33	857	962			
1935	951.47	813	951			
1937	52.56	44	53			
1939	15.58	13	16			
1940	13.75	11	14			
1941	15,225.35	12,435	15,225			
1944	2,221.48	1,772	2,221			
1945	161.26	128	161			
1946	629.70	494	630			
1948	1.00	1	1			
1950	181.23	137	181			
1954	35.07	26	35			
1956	7.72	6	8			
1959	142.79	99	143			
1960	131.99	91	132			
1962	47.49	32	47			
1963	10.00	7	10			
1972	6,120.00	3,653	6,120			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.2 PRODUCING LEASEHOLDS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 55-S0.5						
NET SALVAGE PERCENT.. 0						
1973	7.08	4	7			
1990	260.71	144	257	4	25.65	
1998	3,274.34	1,477	2,638	637	28.58	22
2004	1,098.03	396	707	391	31.04	13
	163,100.33	152,969	162,069	1,031		35

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.5 0.02

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.4 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 60-R1						
NET SALVAGE PERCENT.. 0						
1898	11.00	11	11			
1899	76.80	77	77			
1903	286.00	283	286			
1905	534.24	522	534			
1906	439.95	428	440			
1907	1,303.60	1,260	1,304			
1908	371.67	357	372			
1909	542.65	518	543			
1910	24.50	23	25			
1912	1.00	1	1			
1913	308.44	288	308			
1914	406.05	377	406			
1915	104.20	96	104			
1916	83.46	77	83			
1917	271.07	248	271			
1918	13.60	12	14			
1919	364.18	329	364			
1920	372.95	335	373			
1921	422.37	378	422			
1922	3.00	3	3			
1923	214.30	189	214			
1924	233.93	206	234			
1925	186.30	163	186			
1926	648.74	563	649			
1927	81.77	71	82			
1928	1,265.69	1,085	1,266			
1929	342.53	292	343			
1930	105.29	89	105			
1931	153.25	129	153			
1932	259.70	217	260			
1933	11.55	10	12			
1934	99.17	82	99			
1935	711.79	582	712			
1936	219.39	178	219			
1937	178.48	144	178			
1938	16.54	13	17			
1939	97.49	77	97			
1940	1,167.50	918	1,168			
1941	4,651.28	3,630	4,651			
1942	570.16	441	570			
1943	210.83	162	211			
1944	372.59	283	373			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 325.4 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

CPG
SURVIVOR CURVE.. IOWA 60-R1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1945	869.26	656	869			
1946	288.26	215	288			
1947	1,980.20	1,467	1,980			
1948	494.28	363	494			
1949	1,215.91	884	1,216			
1950	409.99	295	410			
1951	8.42	6	8			
1952	174.36	123	174			
1953	33.53	23	34			
1954	319.31	221	319			
1955	18.46	13	18			
1956	100.07	68	100			
1957	5.20	3	5			
1958	125.16	83	125			
1959	78.61	51	79			
1960	140.63	91	141			
1961	48.55	31	49			
1962	238.74	150	239			
1963	73.00	45	73			
1964	30.64	19	31			
1965	327.04	197	324	3	23.77	
1966	1,949.99	1,161	1,912	38	24.28	2
1967	210.02	123	203	7	24.79	
1968	601.24	348	573	28	25.32	1
1969	260.06	148	244	16	25.84	1
1970	30.26	17	28	2	26.37	
1971	494.97	273	450	45	26.91	2
1972	59.23	32	53	7	27.46	
1973	350.14	187	308	42	28.01	1
1974	44.07	23	38	6	28.56	
1975	183.82	95	156	27	29.12	1
1976	51.01	26	43	8	29.69	
1977	10.01	5	8	2	30.26	
1983	289.96	166	273	17	28.62	1
1992	292.64	140	231	62	32.23	2
1999	643.99	252	415	229	34.97	7
2011	87.04	19	31	56	37.58	1
	30,277.07	23,166	29,681	596		19

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.4 0.06

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 328 FIELD MEASURING AND REGULATING STATION STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1932	154.10	154	154			
1946	22.99	23	23			
1954	330.80	331	331			
1962	466.92	467	467			
1963	288.39	288	288			
	1,263.20	1,263	1,263			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 329 OTHER STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1926	189.95	190	190			
1928	18,125.42	18,125	18,125			
1931	33.50	34	34			
1933	286.63	287	287			
1949	75.00	75	75			
1954	1,624.46	1,624	1,624			
1956	1,968.24	1,968	1,968			
1957	165.09	165	165			
1958	4,854.42	4,854	4,854			
1959	592.97	593	593			
1960	6,765.22	6,765	6,765			
1961	3,361.70	3,362	3,362			
1962	1,509.75	1,510	1,510			
1965	132.84	133	133			
1968	78.04	78	78			
1980	5,021.43	5,021	5,020	2		
	44,784.66	44,784	44,783	2		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 330 PRODUCING GAS WELLS - WELL CONSTRUCTION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1924	704.67	705	705			
1927	1,923.69	1,924	1,924			
1931	1,001.26	1,001	1,001			
1934	627.61	628	628			
1936	108.46	108	108			
1940	17.42	17	17			
1942	3,414.11	3,414	3,414			
1943	779.98	780	780			
1945	470.98	471	471			
1946	6,271.05	6,271	6,271			
1947	904.72	905	905			
1948	274.43	274	274			
1955	331.39	331	331			
1972	894.00	894	894			
2004	484.83	485	486	1-		
	18,208.60	18,208	18,209	1-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 331 PRODUCING GAS WELLS - WELL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1901	115.50	116	116			
1902	202.95	203	203			
1905	127.93	128	128			
1906	12.45	12	12			
1907	1,080.85	1,081	1,081			
1908	1,477.83	1,478	1,478			
1909	298.52	299	299			
1910	158.72	159	159			
1911	277.88	278	278			
1912	291.82	292	292			
1913	214.87	215	215			
1915	441.31	441	441			
1916	189.45	189	189			
1920	640.55	641	641			
1924	501.79	502	502			
1927	432.64	433	433			
1928	569.18	569	569			
1931	299.31	299	299			
1939	388.95	389	389			
1940	380.36	380	380			
1942	672.69	673	673			
1943	957.14	957	957			
1944	255.87	256	256			
1946	812.99	813	813			
1947	296.62	297	297			
1951	235.61	236	236			
1955	200.97	201	201			
1962	296.02	296	296			
1964	413.45	413	413			
1965	1,320.34	1,320	1,320			
1972	10,716.00	10,716	10,716			
1981	66.91	67	67			
1987	93.25	93	94			
	24,440.72	24,442	24,441			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

CPG
SURVIVOR CURVE.. IOWA 47-L0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1895	16.96	13	17			
1898	6,981.14	5,393	6,981			
1899	7,115.14	5,473	7,115			
1901	2,982.56	2,274	2,983			
1902	9,652.93	7,328	9,653			
1903	13,659.72	10,323	13,660			
1904	14,815.75	11,146	14,816			
1905	1,275.77	955	1,276			
1906	513.25	383	513			
1907	6,359.95	4,719	6,360			
1908	3,151.76	2,327	3,152			
1909	2,862.37	2,103	2,862			
1910	307.46	225	307			
1911	2,431.84	1,770	2,432			
1912	2,319.31	1,679	2,319			
1913	5,593.31	4,028	5,593			
1914	6,309.19	4,521	6,309			
1915	4,636.59	3,306	4,637			
1916	6,215.03	4,407	6,215			
1917	4,867.38	3,433	4,867			
1918	88.42	62	88			
1919	3,165.58	2,209	3,166			
1920	11,810.32	8,194	11,810			
1921	1,551.67	1,071	1,552			
1922	4,953.14	3,399	4,953			
1923	1,197.31	817	1,197			
1924	26,520.98	17,989	26,521			
1925	3,581.94	2,415	3,582			
1926	846.23	567	846			
1927	8,969.93	5,975	8,970			
1928	500.19	331	500			
1929	1,246.96	820	1,247			
1930	822.22	538	822			
1931	5,959.34	3,871	5,959			
1932	284.85	184	285			
1933	295.44	189	295			
1934	1,434.24	913	1,434			
1935	734.99	465	735			
1936	655.62	412	656			
1937	590.14	368	590			
1938	1,716.44	1,063	1,716			
1939	6,274.96	3,857	6,275			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 47-L0						
NET SALVAGE PERCENT.. 0						
1940	20,933.33	12,774	20,933			
1941	54,988.08	33,297	54,988			
1942	8,386.40	5,041	8,386			
1943	3,472.45	2,071	3,472			
1944	5,918.84	3,502	5,919			
1945	5,041.98	2,959	5,042			
1946	8,811.89	5,130	8,812			
1947	10,683.12	6,167	10,683			
1948	2,599.34	1,488	2,599			
1949	50,912.72	28,901	50,913			
1950	7,587.88	4,269	7,588			
1951	1,414.44	789	1,414			
1952	2,347.14	1,297	2,347			
1953	485.25	266	485			
1954	7,899.95	4,284	7,900			
1955	7,421.47	3,987	7,421			
1956	7,758.34	4,127	7,758			
1957	11,247.12	5,925	11,247			
1958	19,011.79	9,914	19,012			
1959	5,911.91	3,050	5,912			
1960	9,496.60	4,849	9,478	19	23.00	1
1961	6,128.13	3,095	6,050	79	23.26	3
1962	12,642.83	6,316	12,345	297	23.52	13
1963	10,595.86	5,235	10,232	363	23.78	15
1964	15,728.29	7,680	15,011	717	24.05	30
1965	23,533.62	11,361	22,206	1,327	24.31	55
1966	12,682.25	6,047	11,820	863	24.59	35
1967	21,327.23	10,046	19,636	1,691	24.86	68
1968	24,415.86	11,361	22,206	2,209	25.13	88
1969	23,449.66	10,772	21,055	2,395	25.41	94
1970	9,454.39	4,287	8,379	1,075	25.69	42
1971	20,918.97	9,356	18,287	2,632	25.98	101
1972	26,190.05	11,557	22,590	3,601	26.26	137
1973	25,358.45	11,034	21,567	3,791	26.55	143
1974	4,139.67	1,775	3,469	670	26.85	25
1975	7,177.74	3,033	5,928	1,249	27.14	46
1976	1,091.28	454	887	204	27.44	7
1977	6,710.04	2,750	5,375	1,335	27.74	48
1980	250.51	98	192	59	28.67	2
1982	1,631.45	1,031	1,631			
1983	2,373.67	1,480	2,374			
1985	1,137.79	694	1,138			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 332 FIELD LINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 47-L0						
NET SALVAGE PERCENT.. 0						
1987	1,947.22	1,149	1,947			
1988	7.07	4	7			
1993	1,441.13	772	1,441			
1995	797.78	412	798			
1997	1,112.78	551	1,110	3	25.00	
1998	50,846.74	24,615	49,577	1,270	25.04	51
	750,688.82	422,567	724,840	25,849		1,004

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.7 0.13

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

CPG
SURVIVOR CURVE.. IOWA 24-O3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1931	204.20	195	204			
1936	120.07	102	120			
1941	517.12	387	517			
1942	63.36	46	63			
1943	66.33	47	66			
1945	162.93	109	163			
1946	149.20	97	149			
1947	66.33	42	66			
1948	377.00	230	377			
1949	71.07	42	71			
1950	309.80	177	310			
1952	5,204.61	2,771	4,860	344	11.22	31
1953	1,807.46	929	1,629	178	11.67	15
1957	286.49	126	221	65	13.44	5
1962	1,101.38	388	681	421	15.54	27
1963	4,056.52	1,362	2,389	1,668	15.94	105
1964	170.93	55	96	74	16.34	5
1965	299.84	91	160	140	16.73	8
1966	50.59	15	26	24	17.12	1
1967	1,350.83	366	642	709	17.49	41
1969	2,210.03	531	931	1,279	18.23	70
1970	303.35	69	121	182	18.58	10
1972	595.45	118	207	388	19.26	20
1973	346.72	64	112	234	19.59	12
1975	403.54	64	112	291	20.21	14
1976	97.38	14	25	73	20.51	4
1978	28.40	3	5	23	21.07	1
1979	1,083.00	120	210	873	21.34	41
1980	339.25	34	60	280	21.59	13
1983	53.86	37	54			
1984	379.02	256	379			
1986	2,651.47	1,751	2,651			
1987	6,747.73	4,423	6,748			
1988	1,817.19	1,181	1,817			
1989	141.62	91	142			
1990	1,111.30	707	1,111			
1992	5,631.37	3,522	5,631			
1993	4,412.23	2,729	4,412			
1994	19,381.40	11,885	19,381			
1995	442.09	268	442			
1996	495.45	297	495			
1997	2,814.04	1,668	2,814			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 334 FIELD MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 24-O3						
NET SALVAGE PERCENT.. 0						
2005	37.73	20	38			
2006	8,910.59	4,613	8,911			
2007	11,670.35	5,905	11,670			
2011	1,184.07	530	3,255	2,070-		
	89,724.69	48,477	84,547	5,177		423

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.2 0.47

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 335 DRILLING AND CLEANING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-S0.5						
NET SALVAGE PERCENT.. 0						
1956	11,947.50	11,948	11,948			
1967	4,088.00	3,826	4,088			
1968	19,012.74	17,587	19,013			
1972	5,152.00	4,535	5,152			
1981	3,694.10	2,869	3,600	95	6.70	14
1988	4,516.83	3,601	4,517			
1991	1,192.55	913	1,147	46	9.34	5
	49,603.72	45,279	49,463	140		19

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.4 0.04

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 337 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1928	67.99	68	68			
1940	980.88	981	981			
1941	1,425.13	1,425	1,425			
1950	572.00	572	572			
1952	46.00	46	46			
1954	47.17	47	47			
1956	112.81	113	113			
1959	477.96	478	478			
1961	614.73	615	615			
1963	1,381.00	1,381	1,381			
1966	4,766.93	4,767	4,767			
1967	157.76	158	158			
1968	150.15	150	150			
1969	23.17	23	23			
1970	238.47	238	238			
	11,062.15	11,062	11,062			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1883	45.00	45	45			
1897	69.45	69	69			
1903	3,610.27	3,610	3,610			
1904	4,110.54	4,111	4,111			
1909	44.05	44	44			
1911	85.13	85	85			
1913	835.22	835	835			
1914	222.36	222	222			
1915	14.50	14	15			
1916	224.10	223	224			
1917	117.50	117	118			
1918	64.30	64	64			
1927	6,471.58	6,227	6,355	117	2.65	44
1930	1,806.23	1,719	1,754	52	3.38	15
1931	2,041.31	1,935	1,975	67	3.64	18
1932	27,123.22	25,612	26,137	986	3.90	253
1933	2,640.53	2,484	2,535	106	4.16	25
1934	538.99	505	515	24	4.42	5
1935	812.94	758	774	39	4.69	8
1936	12.64	12	12			
1938	203.24	187	191	12	5.51	2
1939	375.47	344	351	24	5.79	4
1940	962.92	879	897	66	6.07	11
1941	6,450.60	5,864	5,984	466	6.37	73
1942	592.71	536	547	46	6.67	7
1943	337.44	304	310	27	6.99	4
1944	60.01	54	55	5	7.31	1
1945	422.25	376	384	39	7.65	5
1946	631.09	559	570	61	8.00	8
1947	3,351.10	2,951	3,011	340	8.36	41
1948	2,508.33	2,195	2,240	268	8.75	31
1949	4,635.54	4,030	4,113	523	9.15	57
1950	1,157.34	999	1,019	138	9.57	14
1951	190.65	163	166	24	10.02	2
1952	4,042.41	3,437	3,507	535	10.48	51
1953	198.20	167	170	28	10.97	3
1954	5,400.53	4,515	4,608	793	11.48	69
1955	14,353.89	11,891	12,135	2,219	12.01	185
1956	8,390.67	6,884	7,025	1,366	12.57	109
1957	78,471.52	63,730	65,036	13,435	13.15	1,022
1958	2,231.51	1,793	1,830	402	13.76	29
1959	3,854.85	3,063	3,126	729	14.38	51

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
1960	3,405.26	2,675	2,730	675	15.02	45
1961	11,197.19	8,691	8,869	2,328	15.67	149
1962	2,660.99	2,040	2,082	579	16.33	35
1963	3,222.41	2,439	2,489	733	17.01	43
1964	3,157.03	2,359	2,407	750	17.70	42
1965	5,365.41	3,956	4,037	1,328	18.39	72
1966	6,572.95	4,779	4,877	1,696	19.10	89
1967	36,334.10	26,052	26,586	9,748	19.81	492
1968	22,318.73	15,770	16,093	6,226	20.54	303
1969	3,796.90	2,643	2,697	1,100	21.28	52
1970	12,470.57	8,546	8,721	3,749	22.03	170
1971	18,015.96	12,153	12,402	5,614	22.78	246
1972	1,199.64	796	812	387	23.55	16
1973	11,935.28	7,787	7,947	3,989	24.33	164
1974	5,080.37	3,257	3,324	1,757	25.12	70
1975	8,346.12	5,254	5,362	2,984	25.93	115
1976	11,480.98	7,095	7,240	4,241	26.74	159
1977	7,995.15	4,847	4,946	3,049	27.56	111
1978	11,905.30	7,077	7,222	4,683	28.39	165
1979	12,918.41	7,524	7,678	5,240	29.23	179
1980	7,570.24	4,316	4,404	3,166	30.09	105
1981	4,856.13	2,709	2,765	2,092	30.95	68
1982	73,749.17	42,244	43,110	30,639	29.46	1,040
1983	10,050.64	5,649	5,765	4,286	29.99	143
1984	9,041.47	4,950	5,051	3,990	30.99	129
1985	15,250.78	8,184	8,352	6,899	31.52	219
1986	26,754.50	13,960	14,246	12,508	32.53	385
1987	14,112.19	7,158	7,305	6,807	33.52	203
1988	3,342.10	1,657	1,691	1,651	34.07	48
1989	11,301.63	5,436	5,547	5,754	35.07	164
1990	1,090.00	508	518	572	36.07	16
1991	8,000.14	3,611	3,685	4,315	37.07	116
1992	117,309.04	51,569	52,626	64,683	37.61	1,720
1993	25,030.74	10,628	10,846	14,185	38.62	367
1994	12,460.42	5,106	5,211	7,250	39.61	183
1995	6,889.97	2,720	2,776	4,114	40.62	101
1996	12,673.77	4,848	4,947	7,726	41.17	188
1997	12,902.15	4,742	4,839	8,063	42.17	191
1998	66,382.78	23,400	23,880	42,503	43.17	985
1999	16,831.93	5,681	5,797	11,034	44.17	250
2000	2,877.07	928	947	1,930	45.17	43
2001	5,944.43	1,828	1,865	4,079	46.17	88

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 365.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. 0						
2002	2,355.47	693	707	1,648	46.73	35
2003	1,306.89	365	372	934	47.72	20
2004	373.65	99	101	273	48.73	6
2007	10,611.38	2,324	2,372	8,240	51.72	159
	868,159.56	514,665	525,023	343,136		11,836

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.0 1.36

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

CPG
SURVIVOR CURVE.. IOWA 30-R1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1916	44.03	44	44			
1932	22.41	22	22			
1937	428.90	429	429			
1940	2,662.19	2,662	2,662			
1941	342.66	343	343			
1947	195.14	195	195			
1954	97.16	97	97			
1955	398.72	399	399			
1956	1,082.26	1,082	1,082			
1957	2,295.78	2,296	2,296			
1958	310.18	310	310			
1959	2,058.46	2,058	2,058			
1960	300.33	300	300			
1961	6,541.37	6,541	6,541			
1962	4,353.35	4,314	4,353			
1963	2,282.71	2,237	2,283			
1964	736.08	713	736			
1965	190.55	183	191			
1966	2,343.06	2,218	2,343			
1967	2,250.24	2,107	2,250			
1968	9,977.71	9,243	9,978			
1969	2,151.32	1,971	2,151			
1970	544.69	494	545			
1971	40.03	36	40			
1972	1,214.19	1,076	1,214			
1974	700.59	606	701			
1975	4,750.87	4,059	4,751			
1978	193.66	159	190	4	5.39	1
1979	2,207.46	1,784	2,128	79	5.75	14
1980	2,203.60	1,754	2,092	111	6.12	18
1984	5,281.99	4,437	5,282			
1985	369.17	307	366	3	7.36	
1986	9,821.44	8,054	9,609	213	7.79	27
1987	241.46	195	233	9	8.24	1
1988	1,014.54	809	965	49	8.52	6
1989	31,015.80	24,394	29,103	1,913	8.82	217
1990	44,844.88	34,611	41,292	3,553	9.31	382
1995	601.90	423	505	97	11.24	9
1997	1,215.58	813	970	246	12.13	20
1999	1,575.63	1,000	1,193	383	12.96	30

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 366 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 30-R1						
NET SALVAGE PERCENT.. 0						
2004	1,760.08	946	1,129	631	15.07	42
2019	11,416.29	1,372	1,637	9,779	18.29	535
2020	138.01	11	13	125	17.48	7
	162,216.47	127,104	145,020	17,196		1,309

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.1 0.81

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
1901	71,233.81	71,234	71,234			
1903	24,056.23	24,056	24,056			
1904	33,197.34	32,979	33,197			
1905	1,964.62	1,951	1,965			
1907	2,420.69	2,389	2,421			
1908	8,730.25	8,586	8,730			
1911	749.15	729	749			
1914	1,738.46	1,674	1,738			
1916	77.22	74	77			
1923	35.55	33	36			
1926	1,356.81	1,247	1,357			
1927	46,464.38	42,541	46,464			
1928	2,171.63	1,981	2,172			
1929	180.25	164	180			
1930	27,529.19	24,898	27,529			
1931	2,522.76	2,272	2,523			
1932	296.56	266	297			
1933	122,819.26	109,678	122,819			
1934	4,897.35	4,354	4,897			
1935	10,855.44	9,607	10,855			
1936	1,410.95	1,243	1,411			
1937	16,622.35	14,571	16,622			
1938	2,388.88	2,084	2,389			
1939	2,797.65	2,428	2,798			
1940	797.65	688	798			
1941	11,364.66	9,756	11,365			
1942	11,633.51	9,930	11,634			
1943	1,215.69	1,031	1,216			
1944	5,838.88	4,924	5,834	5	10.97	
1945	48.34	41	48			
1946	1,498.10	1,247	1,477	21	11.74	2
1947	4,905.03	4,054	4,803	102	12.15	8
1948	24,941.60	20,466	24,246	695	12.56	55
1949	98,837.20	80,496	95,365	3,472	12.99	267
1950	28,199.11	22,789	26,998	1,201	13.43	89
1951	2,735.68	2,193	2,598	138	13.89	10
1952	202,177.37	160,703	190,387	11,790	14.36	821
1953	22,207.66	17,500	20,733	1,475	14.84	99
1954	200,020.82	156,188	185,038	14,983	15.34	977
1955	798,248.09	617,501	731,563	66,685	15.85	4,207
1956	81,749.31	62,631	74,200	7,549	16.37	461
1957	1,473,781.22	1,117,760	1,324,227	149,554	16.91	8,844

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
1958	311,182.44	233,564	276,707	34,476	17.46	1,975
1959	299,804.72	222,584	263,699	36,106	18.03	2,003
1960	613,382.05	450,400	533,596	79,786	18.60	4,290
1961	674,919.59	489,897	580,388	94,531	19.19	4,926
1962	47,891.52	34,352	40,697	7,194	19.79	364
1963	190,718.09	135,110	160,067	30,651	20.41	1,502
1964	122,060.87	85,390	101,163	20,898	21.03	994
1965	290,969.66	200,894	238,002	52,968	21.67	2,444
1966	701,420.51	477,766	566,016	135,404	22.32	6,066
1967	720,897.81	484,234	573,679	147,219	22.98	6,406
1968	215,827.53	142,908	169,305	46,522	23.65	1,967
1969	370,389.64	241,653	286,290	84,100	24.33	3,457
1970	640,788.57	411,752	487,809	152,980	25.02	6,114
1971	875,035.93	553,521	655,765	219,271	25.72	8,525
1972	453,960.20	282,558	334,751	119,210	26.43	4,510
1973	966,619.22	591,851	701,175	265,445	27.14	9,781
1974	373,697.43	224,914	266,459	107,238	27.87	3,848
1975	486,480.16	287,651	340,784	145,696	28.61	5,092
1976	297,117.41	172,539	204,410	92,708	29.35	3,159
1977	137,471.87	78,340	92,811	44,661	30.11	1,483
1978	136,380.55	76,237	90,319	46,061	30.87	1,492
1979	287,058.05	157,308	186,365	100,693	31.64	3,182
1980	501,981.46	269,494	319,274	182,708	32.42	5,636
1981	243,613.68	128,070	151,726	91,887	33.20	2,768
1982	283,711.51	160,240	189,839	93,873	30.43	3,085
1983	319,398.12	177,074	209,782	109,616	30.94	3,543
1984	524,887.81	283,439	335,794	189,093	31.94	5,920
1985	749,802.45	396,795	470,089	279,714	32.47	8,615
1986	455,843.70	236,264	279,905	175,938	32.99	5,333
1987	565,064.08	284,623	337,197	227,867	33.99	6,704
1988	414,536.27	204,118	241,822	172,715	34.53	5,002
1989	491,903.15	236,605	280,309	211,594	35.07	6,033
1990	207,476.32	96,725	114,592	92,885	36.07	2,575
1991	360,151.18	163,653	193,882	166,269	36.62	4,540
1992	2,298,208.76	1,010,293	1,196,909	1,101,300	37.61	29,282
1993	1,177,930.89	503,565	596,581	581,350	38.17	15,231
1994	1,136,543.85	471,893	559,059	577,485	38.73	14,911
1995	971,986.45	388,989	460,841	511,145	39.72	12,869
1996	571,723.50	221,600	262,533	309,191	40.29	7,674
1997	818,847.73	304,939	361,266	457,582	41.29	11,082
1998	2,005,922.41	721,330	854,570	1,151,352	41.86	27,505
1999	1,775,496.88	611,126	724,010	1,051,487	42.86	24,533

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 367 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. 0						
2000	1,018,766.50	337,314	399,621	619,146	43.44	14,253
2001	2,255,155.44	716,688	849,071	1,406,084	44.01	31,949
2002	827,071.64	249,941	296,109	530,963	45.02	11,794
2003	1,841,712.23	531,518	629,697	1,212,015	45.60	26,579
2004	339,445.60	92,669	109,786	229,659	46.60	4,928
2005	46,687.55	12,092	14,326	32,362	47.20	686
2006	317,437.09	77,264	91,536	225,901	48.19	4,688
2007	479,147.65	109,773	130,050	349,098	48.79	7,155
2008	171,988.56	36,685	43,461	128,527	49.79	2,581
2009	12,014.64	2,389	2,830	9,184	50.39	182
2010	222,615.19	40,694	48,211	174,404	51.40	3,393
2011	140,623.77	23,625	27,989	112,635	52.00	2,166
2012	28,451.16	4,325	5,124	23,327	53.00	440
2013	2,361,672.12	323,077	382,754	1,978,918	53.61	36,913
2014	9,397.12	1,135	1,345	8,052	54.61	147
2021	556,489.83	4,730	5,604	550,886	58.32	9,446
	39,074,496.81	18,121,114	21,426,794	17,647,702		459,561

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.4 1.18

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2						
NET SALVAGE PERCENT.. 0						
1928	43.41	43	43			
1936	1.00	1	1			
1938	63.36	61	63			
1939	130.20	124	130			
1940	199.99	190	200			
1941	188.95	178	189			
1943	115.52	108	116			
1944	207.70	192	208			
1945	83.77	77	84			
1946	174.42	159	174			
1947	163.63	149	164			
1948	277.29	250	277			
1949	89.09	80	89			
1951	7.97	7	8			
1953	18.79	16	19			
1954	5,944.35	5,145	5,944			
1955	8,508.82	7,311	8,509			
1956	7,542.08	6,432	7,542			
1957	39,702.37	33,609	39,702			
1958	13,574.54	11,403	13,575			
1959	6,469.06	5,390	6,460	9	8.17	1
1960	9,801.88	8,100	9,708	93	8.51	11
1961	24,067.26	19,720	23,636	431	8.85	49
1962	5,498.45	4,466	5,353	146	9.20	16
1963	12,455.03	10,022	12,012	443	9.57	46
1964	5,203.12	4,148	4,972	231	9.94	23
1965	19,172.75	15,135	18,140	1,032	10.32	100
1966	16,408.17	12,818	15,363	1,045	10.72	97
1967	43,116.46	33,332	39,951	3,166	11.12	285
1968	18,626.28	14,240	17,068	1,559	11.54	135
1969	18,055.59	13,649	16,359	1,696	11.96	142
1970	32,278.33	24,110	28,898	3,381	12.40	273
1971	15,250.12	11,248	13,482	1,769	12.86	138
1972	26,308.31	19,157	22,961	3,347	13.32	251
1973	26,694.33	19,182	22,991	3,703	13.79	269
1974	12,036.90	8,529	10,223	1,814	14.28	127
1975	18,632.52	13,012	15,596	3,037	14.78	205
1976	30,467.80	20,961	25,123	5,345	15.29	350
1977	138,678.97	93,905	112,552	26,127	15.82	1,652
1978	14,832.80	9,880	11,842	2,991	16.36	183
1979	22,161.07	14,518	17,401	4,760	16.90	282
1980	41,008.38	26,396	31,637	9,371	17.46	537

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 369 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 49-R2						
NET SALVAGE PERCENT.. 0						
1981	13,577.55	8,579	10,283	3,295	18.04	183
1982	82,437.31	57,962	69,472	12,966	16.68	777
1983	156,845.27	108,694	130,277	26,568	17.06	1,557
1984	24,048.18	16,413	19,672	4,376	17.45	251
1985	50,677.87	33,853	40,575	10,103	18.14	557
1986	86,879.75	57,063	68,394	18,486	18.55	997
1987	86,985.91	56,123	67,267	19,719	18.97	1,039
1988	52,185.49	32,866	39,392	12,793	19.69	650
1989	411,643.09	254,190	304,665	106,978	20.13	5,314
1990	41,658.60	25,195	30,198	11,461	20.58	557
1991	297,917.74	176,278	211,282	86,636	21.05	4,116
1992	147,610.27	84,905	101,765	45,846	21.78	2,105
1993	264,883.76	148,706	178,235	86,649	22.26	3,893
1994	163,266.69	89,340	107,080	56,186	22.75	2,470
1995	349,935.44	186,376	223,385	126,551	23.25	5,443
1996	117,235.62	60,388	72,379	44,856	24.00	1,869
1997	215,121.50	107,518	128,868	86,254	24.52	3,518
1998	739,635.18	358,057	429,157	310,479	25.04	12,399
1999	555,284.44	259,873	311,476	243,808	25.58	9,531
2000	30,572.58	13,804	16,545	14,028	26.12	537
2001	311,654.86	135,445	162,340	149,314	26.67	5,599
2002	420,021.01	175,275	210,079	209,942	27.23	7,710
2003	302,736.01	120,973	144,995	157,741	27.80	5,674
2004	113,854.85	43,436	52,061	61,794	28.37	2,178
2005	92,462.88	33,564	40,229	52,234	28.95	1,804
2006	61,754.44	21,250	25,470	36,285	29.55	1,228
2007	43,243.40	14,106	16,907	26,336	29.95	879
2008	249,781.89	76,533	91,730	158,052	30.56	5,172
2012	19,034.42	4,304	5,159	13,876	32.52	427
2013	11,199.27	2,294	2,750	8,450	33.00	256
2021	3,931.62	61	73	3,859	32.07	120
	6,152,337.72	3,230,877	3,870,923	2,281,415		93,982

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.3   1.53

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 370 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 23-R0.5						
NET SALVAGE PERCENT.. 0						
1956	5,466.25	5,466	5,466			
1966	7,727.57	7,728	7,728			
1967	1,743.15	1,743	1,743			
1968	249.76	250	250			
1969	2,500.34	2,500	2,500			
1973	1,946.45	1,946	1,946			
1980	706.12	641	706			
1983	5,572.11	5,149	5,572			
1984	1,354.71	1,234	1,355			
1985	2,338.50	2,108	2,339			
1986	8,363.40	7,452	8,363			
1987	1,865.01	1,641	1,865			
1988	8,236.27	7,146	8,236			
1989	56,812.32	48,745	56,812			
1990	6,202.17	5,236	6,202			
1991	81,477.96	67,839	81,478			
1992	19,398.63	15,909	19,399			
1993	11,826.34	9,539	11,826			
1994	4,988.84	3,965	4,989			
1995	24,237.82	18,884	23,778	460	7.51	61
1996	53,971.10	41,288	51,989	1,983	7.83	253
1997	2,814.71	2,110	2,657	158	8.18	19
1998	270.53	198	249	21	8.55	2
2000	83,012.05	57,826	72,813	10,199	9.36	1,090
2001	21,876.59	14,845	18,692	3,184	9.71	328
2004	19,336.59	11,979	15,084	4,253	10.75	396
2009	239,511.48	119,756	150,793	88,719	12.50	7,098
2010	493,162.42	233,660	294,217	198,945	12.77	15,579
2011	679,759.29	302,629	381,061	298,698	13.08	22,836
2012	572,350.00	238,155	299,877	272,473	13.33	20,441
2013	629,591.21	242,393	305,214	324,378	13.58	23,886
2014	214,236.53	75,668	95,279	118,958	13.73	8,664
2015	223,230.20	71,389	89,891	133,339	13.83	9,641
	3,486,136.42	1,627,017	2,030,369	1,455,768		110,294

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.2 3.16

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1932	73.41	73	73			
1933	22.79	23	23			
1935	159.65	160	160			
1936	148.67	149	149			
1938	75.60	76	76			
1939	348.00	348	348			
1953	193.45	193	193			
1957	802.14	799	802			
1959	54.05	53	54			
1960	1,630.62	1,589	1,631			
1963	268.78	256	269			
1965	542.39	508	542			
1966	237.71	221	238			
1967	1,610.42	1,486	1,610			
1968	1,046.31	959	1,046			
1969	8,185.23	7,451	8,185			
1970	1,294.81	1,171	1,295			
1971	2,302.48	2,067	2,302			
1972	4,402.26	3,923	4,402			
1973	6,378.34	5,642	6,378			
1974	2,116.13	1,858	2,116			
1975	772.96	673	773			
1976	728.51	629	728	1	4.77	
1977	666.84	571	661	6	5.03	1
1978	2,372.22	2,013	2,330	42	5.30	8
1979	395.78	333	385	10	5.58	2
1980	1,489.70	1,239	1,434	56	5.89	10
1981	1,156.83	952	1,102	55	6.21	9
1982	1,410.00	1,220	1,410			
1983	4,310.08	3,701	4,284	26	6.34	4
1984	3,348.16	2,838	3,285	63	6.75	9
1985	3,634.15	3,051	3,531	103	6.98	15
1986	5,292.73	4,378	5,067	226	7.42	30
1987	1,466.52	1,194	1,382	85	7.87	11
1988	1,617.48	1,295	1,499	119	8.34	14
1989	7,215.84	5,699	6,596	620	8.65	72
1990	11,462.74	8,882	10,280	1,183	9.15	129
1991	14,888.28	11,306	13,086	1,802	9.66	187
1992	14,350.24	10,668	12,347	2,003	10.18	197
1993	10,561.54	7,676	8,884	1,677	10.71	157

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1994	9,905.10	7,054	8,164	1,741	11.11	157
1995	3,879.74	2,694	3,118	762	11.67	65
1996	7,818.56	5,284	6,116	1,703	12.23	139
	140,637.24	112,355	128,356	12,281		1,216

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.1 0.86

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 371.1 TESTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 20-R3						
NET SALVAGE PERCENT.. 0						
1983	15,664.23	15,664	15,664			
1984	11,125.29	11,125	11,125			
1986	4,384.63	4,385	4,385			
1987	38,021.86	38,022	38,022			
1991	11,962.90	11,712	11,963			
1992	2,199.99	2,129	2,200			
1993	1,383.30	1,329	1,383			
1996	24,385.78	22,635	24,386			
1997	494.25	453	488	6	2.24	3
2015	100,388.74	35,036	37,779	62,610	12.12	5,166
	210,010.97	142,490	147,396	62,615		5,169

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.1 2.46

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1904	298.00	289	298			
1905	222.17	215	222			
1930	410.41	361	410			
1931	548.08	480	548			
1932	10,677.87	9,315	10,678			
1933	38.71	34	39			
1934	55.00	48	55			
1935	123.52	106	123	1	10.53	
1936	533.10	456	529	4	10.87	
1937	100.54	85	99	2	11.22	
1938	223.29	189	219	4	11.59	
1939	178.56	150	174	5	11.96	
1940	285.78	239	277	9	12.34	1
1941	249.96	207	240	10	12.74	1
1942	57.82	48	56	2	13.14	
1943	19.44	16	19	1	13.56	
1945	36.92	30	35	2	14.44	
1946	59.80	48	56	4	14.90	
1947	160.11	127	147	13	15.37	1
1948	235.63	186	216	20	15.85	1
1949	51.03	40	46	5	16.35	
1950	2,077.70	1,611	1,869	209	16.85	12
1951	1,726.56	1,327	1,539	187	17.37	11
1952	360.18	274	318	42	17.91	2
1953	287.05	216	251	36	18.45	2
1954	1,145.40	855	992	154	19.01	8
1955	877.98	649	753	125	19.58	6
1956	3,133.21	2,291	2,658	476	20.16	24
1957	1,794.30	1,298	1,506	289	20.75	14
1958	5,277.55	3,775	4,379	898	21.36	42
1959	1,136.57	803	932	205	21.98	9
1960	1,431.64	1,000	1,160	272	22.60	12
1961	1,139.60	786	912	228	23.24	10
1962	1,739.80	1,186	1,376	364	23.89	15
1963	534.64	360	418	117	24.55	5
1964	1,024.78	680	789	236	25.22	9
1965	2,424.42	1,588	1,842	582	25.89	22
1966	1,904.74	1,230	1,427	478	26.58	18
1967	14,200.26	9,035	10,481	3,719	27.28	136
1968	36,083.66	22,622	26,243	9,841	27.98	352
1969	18,362.30	11,336	13,150	5,212	28.70	182
1970	11,282.03	6,856	7,953	3,329	29.42	113

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1971	6,080.40	3,636	4,218	1,862	30.15	62
1972	15,534.05	9,136	10,598	4,936	30.89	160
1973	18,498.57	10,695	12,407	6,092	31.64	193
1974	38,364.70	21,796	25,285	13,080	32.39	404
1975	49,272.90	27,494	31,895	17,378	33.15	524
1976	37,863.68	20,739	24,058	13,805	33.92	407
1977	13,898.67	7,468	8,663	5,235	34.70	151
1978	19,181.60	10,105	11,722	7,459	35.49	210
1979	24,833.70	12,821	14,873	9,961	36.28	275
1980	27,735.34	14,023	16,267	11,468	37.08	309
1981	38,526.40	19,068	22,120	16,406	37.88	433
1982	41,644.61	22,205	25,759	15,886	34.58	459
1983	29,660.39	15,530	18,016	11,645	35.03	332
1984	47,020.30	23,980	27,818	19,202	36.03	533
1985	51,245.11	25,623	29,724	21,521	36.50	590
1986	70,214.20	34,152	39,618	30,596	37.49	816
1987	74,675.20	35,553	41,243	33,432	37.96	881
1988	61,590.79	28,473	33,030	28,561	38.96	733
1989	64,488.00	29,136	33,799	30,689	39.44	778
1990	63,293.80	27,913	32,381	30,913	39.93	774
1991	76,971.45	32,867	38,128	38,844	40.93	949
1992	69,790.71	29,033	33,680	36,111	41.42	872
1993	74,877.76	30,086	34,901	39,976	42.43	942
1994	94,389.03	36,859	42,758	51,631	42.92	1,203
1995	63,758.76	23,992	27,832	35,927	43.92	818
1996	64,141.55	23,386	27,129	37,012	44.43	833
1997	72,745.02	25,490	29,570	43,175	45.43	950
1998	147,067.21	49,768	57,734	89,334	45.94	1,945
1999	227,532.44	73,721	85,520	142,012	46.94	3,025
2000	113,292.57	35,075	40,689	72,604	47.94	1,514
2001	143,018.46	42,505	49,308	93,710	48.47	1,933
2002	79,103.65	22,371	25,952	53,152	49.46	1,075
2003	48,457.78	13,088	15,183	33,275	49.99	666
2004	457,077.76	116,783	135,475	321,603	50.99	6,307
2005	156,879.83	38,059	44,151	112,729	51.52	2,188
2006	18,899.98	4,305	4,994	13,906	52.53	265
2007	23,188.64	4,976	5,772	17,416	53.07	328
2008	111,323.88	22,243	25,803	85,521	54.07	1,582
2009	31,652.25	5,894	6,837	24,815	54.62	454
2010	18,984.06	3,254	3,775	15,209	55.61	273
2011	16,496.41	2,580	2,993	13,503	56.62	238
2012	11,716.78	1,670	1,937	9,779	57.17	171

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 374.2 RIGHTS-OF-WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
2013	7,230.17	922	1,070	6,161	58.17	106
2014	96,772.18	10,955	12,708	84,064	58.73	1,431
2015	3,854.69	379	440	3,415	59.72	57
2016	108,433.77	9,065	10,516	97,918	60.29	1,624
2017	1,733.31	119	138	1,595	60.86	26
2018	88,813.28	4,760	5,522	83,291	61.86	1,346
2019	734.26	28	32	702	62.44	11
2020	180,290.57	4,219	4,894	175,396	62.60	2,802
2021	19,208.11	152	176	19,032	62.79	303
	3,544,568.84	1,150,597	1,334,545	2,210,024		46,269

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.8 1.31

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1849	2,794.87	2,795	2,795			
1867	72.39	72	72			
1888	4,192.87	4,193	4,193			
1897	178.89	179	179			
1898	159.45	159	159			
1902	1,745.39	1,745	1,745			
1905	1,321.50	1,322	1,322			
1906	2,135.22	2,135	2,135			
1908	880.43	880	880			
1909	1,063.58	1,064	1,064			
1910	681.05	681	681			
1912	356.78	357	357			
1916	122.09	122	122			
1917	5,254.50	5,254	5,255			
1918	4,743.98	4,744	4,744			
1919	2,219.29	2,219	2,219			
1920	2,532.43	2,532	2,532			
1921	17,407.66	17,408	17,408			
1922	1,544.59	1,537	1,545			
1923	444.90	440	445			
1924	49,481.98	48,581	49,482			
1925	9,550.78	9,310	9,551			
1926	1,437.54	1,391	1,438			
1927	12,634.65	12,142	12,635			
1928	169.18	161	169			
1929	1,786.94	1,693	1,787			
1930	6,130.68	5,767	6,131			
1931	886.67	828	887			
1932	690.68	640	691			
1933	4,845.58	4,460	4,846			
1934	599.15	547	599			
1937	206.12	184	206			
1939	941.28	829	941			
1941	1,497.83	1,298	1,477	21	6.66	3
1942	1,321.59	1,137	1,294	28	7.00	4
1943	3,799.03	3,241	3,687	112	7.34	15
1944	480.46	407	463	17	7.68	2
1945	7,388.06	6,203	7,057	331	8.02	41
1946	24,241.93	20,189	22,968	1,273	8.36	152
1947	1,212.46	1,001	1,139	74	8.70	9
1948	11,813.70	9,675	11,007	807	9.05	89
1949	155,416.10	126,198	143,572	11,844	9.40	1,260

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1950	314,773.72	253,393	288,278	26,496	9.75	2,718
1951	117,565.93	93,818	106,734	10,832	10.10	1,072
1952	14,011.46	11,083	12,609	1,403	10.45	134
1953	64,035.02	50,191	57,101	6,934	10.81	641
1954	82,747.60	64,262	73,109	9,639	11.17	863
1955	21,708.32	16,702	19,001	2,707	11.53	235
1956	33,265.27	25,355	28,846	4,420	11.89	372
1957	17,019.75	12,847	14,616	2,404	12.26	196
1958	16,398.95	12,257	13,944	2,455	12.63	194
1959	36,119.98	26,729	30,409	5,711	13.00	439
1960	28,812.28	21,102	24,007	4,805	13.38	359
1961	30,404.90	22,037	25,071	5,334	13.76	388
1962	27,753.65	19,905	22,645	5,108	14.14	361
1963	14,913.85	10,583	12,040	2,874	14.52	198
1964	4,880.13	3,425	3,897	984	14.91	66
1965	18,536.25	12,860	14,630	3,906	15.31	255
1966	5,038.93	3,457	3,933	1,106	15.70	70
1967	4,718.58	3,198	3,638	1,080	16.11	67
1968	4,278.86	2,866	3,261	1,018	16.51	62
1969	8,771.59	5,803	6,602	2,170	16.92	128
1970	5,741.53	3,750	4,266	1,475	17.34	85
1971	36,049.81	23,252	26,453	9,597	17.75	541
1973	11,871.49	7,453	8,479	3,392	18.61	182
1974	25,525.37	15,805	17,981	7,544	19.04	396
1975	87,663.74	53,510	60,877	26,787	19.48	1,375
1976	4,598.73	2,766	3,147	1,452	19.93	73
1977	8,040.17	4,763	5,419	2,621	20.38	129
1978	13,389.00	7,811	8,886	4,503	20.83	216
1979	6,024.51	3,459	3,935	2,089	21.29	98
1980	2,625.97	1,483	1,687	939	21.76	43
1981	3,896.41	2,163	2,461	1,436	22.24	65
1982	4,195.18	2,817	3,205	990	19.32	51
1984	107,312.77	69,625	79,210	28,102	20.30	1,384
1985	3,250.91	2,077	2,363	888	20.64	43
1987	11,800.00	7,328	8,337	3,463	21.06	164
1989	18,115.32	10,833	12,324	5,791	21.85	265
1990	3,722.71	2,181	2,481	1,241	22.26	56
1993	4,421.64	2,432	2,767	1,655	23.32	71
1995	3,605.96	1,892	2,152	1,453	24.01	61
1996	28,053.64	14,307	16,277	11,777	24.50	481
1998	37,254.30	17,949	20,420	16,834	25.28	666
1999	24,770.91	11,593	13,189	11,582	25.58	453

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2000	23,959.75	10,868	12,364	11,596	25.90	448
2001	34,304.98	14,978	17,040	17,265	26.45	653
2002	6,262.15	2,638	3,001	3,261	26.80	122
2003	8,507.00	3,447	3,922	4,585	27.16	169
2004	14,150.50	5,497	6,254	7,897	27.55	287
2005	14,063.28	5,220	5,939	8,125	27.95	291
2006	17,523.06	6,193	7,046	10,477	28.36	369
2007	55,195.64	18,491	21,037	34,159	28.79	1,186
2008	20,558.92	6,521	7,419	13,140	29.06	452
2011	27,987.49	7,198	8,189	19,799	30.32	653
2013	103,921.61	22,260	25,325	78,597	31.18	2,521
2014	188,343.09	36,162	41,140	147,203	31.56	4,664
2019	56,478.77	3,925	4,465	52,013	33.47	1,554
2020	20,252.13	859	977	19,275	33.84	570
2021	8,253.67	119	135	8,118	34.10	238
	2,263,831.38	1,391,218	1,566,816	697,016		31,468
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1901	435.33	435	435			
1914	47.48	47	47			
1922	4,142.29	4,122	4,142			
1927	2,693.18	2,588	2,693			
1930	189.29	178	189			
1933	847.72	780	848			
1936	544.45	490	544			
1938	32.84	29	33			
1952	9,309.40	7,364	9,295	15	10.45	1
1956	5,775.22	4,402	5,556	219	11.89	18
1957	65,555.21	49,481	62,454	3,101	12.26	253
1958	3,928.05	2,936	3,706	222	12.63	18
1959	1,740.26	1,288	1,626	115	13.00	9
1960	10,837.04	7,937	10,018	819	13.38	61
1961	15,330.33	11,111	14,024	1,306	13.76	95
1962	44,412.35	31,853	40,204	4,208	14.14	298
1963	61,579.91	43,697	55,153	6,427	14.52	443
1964	33,613.04	23,590	29,775	3,838	14.91	257
1965	24,530.54	17,019	21,481	3,050	15.31	199

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1966	16,505.84	11,323	14,292	2,214	15.70	141
1967	43,814.66	29,698	37,484	6,331	16.11	393
1968	27,948.53	18,720	23,628	4,321	16.51	262
1969	34,014.41	22,504	28,404	5,610	16.92	332
1970	109,477.63	71,511	90,260	19,218	17.34	1,108
1971	28,682.10	18,500	23,350	5,332	17.75	300
1972	14,929.02	9,501	11,992	2,937	18.18	162
1973	43,388.65	27,239	34,380	9,008	18.61	484
1974	6,679.10	4,136	5,220	1,459	19.04	77
1975	2,388.78	1,458	1,840	549	19.48	28
1976	325.75	196	247	78	19.93	4
1977	310.42	184	232	78	20.38	4
1978	5,350.19	3,121	3,939	1,411	20.83	68
1979	1,782.45	1,023	1,291	491	21.29	23
1980	6,278.95	3,546	4,476	1,803	21.76	83
1981	51,214.65	28,434	35,889	15,326	22.24	689
1982	55,560.11	37,309	47,091	8,470	19.32	438
1983	28,861.79	19,112	24,123	4,739	19.64	241
1984	5,806.34	3,767	4,755	1,052	20.30	52
1985	10,388.00	6,636	8,376	2,012	20.64	97
1986	10,162.46	6,422	8,106	2,057	20.68	99
1987	22,171.50	13,769	17,379	4,793	21.06	228
1988	9,500.30	5,792	7,311	2,190	21.45	102
1989	21,764.75	13,015	16,427	5,338	21.85	244
1990	17,697.49	10,369	13,088	4,610	22.26	207
1991	2,527.62	1,449	1,829	699	22.69	31
1992	778.74	439	554	225	22.86	10
1993	14,187.04	7,803	9,849	4,338	23.32	186
1994	30,706.90	16,465	20,782	9,925	23.78	417
1995	14,521.42	7,619	9,617	4,905	24.01	204
1996	64,620.77	32,957	41,598	23,023	24.50	940
1997	90,222.73	44,877	56,643	33,580	24.76	1,356
1998	90,466.61	43,587	55,015	35,452	25.28	1,402
1999	26,987.42	12,630	15,941	11,046	25.58	432
2000	22,242.63	10,089	12,734	9,509	25.90	367
2001	27,792.71	12,134	15,315	12,477	26.45	472
2002	74,704.50	31,466	39,716	34,989	26.80	1,306
2003	35,723.93	14,475	18,270	17,454	27.16	643
2004	12,600.58	4,895	6,178	6,422	27.55	233
2005	1,094.30	406	512	582	27.95	21
2006	2,275.29	804	1,015	1,260	28.36	44
2007	50,329.62	16,860	21,280	29,049	28.79	1,009

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2008	4,380.00	1,389	1,753	2,627	29.06	90
2009	6,511.91	1,937	2,445	4,067	29.52	138
2010	2,023.74	561	708	1,316	29.99	44
2014	1,151,949.73	221,174	279,161	872,789	31.56	27,655
2017	18,705.63	2,256	2,847	15,858	32.81	483
2019	87,261.18	6,065	7,655	79,606	33.47	2,378
2020	35,549.59	1,507	1,902	33,647	33.84	994
	2,728,712.39	1,070,476	1,349,122	1,379,591		48,373
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1862	16.00	16	16			
1901	123.38	123	123			
1903	2,860.00	2,860	2,860			
1909	2,901.80	2,902	2,902			
1911	7,556.70	7,557	7,557			
1916	161.12	161	161			
1924	266.11	261	266			
1926	212.80	206	213			
1928	13,724.13	13,096	13,724			
1929	894.16	847	894			
1931	38.28	36	38			
1937	572.62	512	573			
1938	4,600.60	4,081	4,601			
1946	12.36	10	12			
1948	432.79	354	433			
1949	6,857.71	5,568	6,858			
1950	1,464.38	1,179	1,464			
1951	23,781.96	18,978	23,782			
1953	8.07	6	8			
1954	1,809.10	1,405	1,809			
1955	0.60			1	11.53	
1956	768.66	586	769			
1957	123.78	93	124			
1958	1,865.14	1,394	1,863	2	12.63	
1960	2,255.90	1,652	2,208	48	13.38	4
1961	2,692.32	1,951	2,608	84	13.76	6
1962	2,889.36	2,072	2,770	120	14.14	8

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
1963	2,147.00	1,524	2,037	110	14.52	8
1964	1,552.28	1,089	1,456	97	14.91	7
1965	251.74	175	234	18	15.31	1
1966	898.68	616	823	75	15.70	5
1967	2,957.44	2,005	2,680	277	16.11	17
1968	6,310.72	4,227	5,650	660	16.51	40
1969	8,455.01	5,594	7,478	977	16.92	58
1970	1,245.94	814	1,088	158	17.34	9
1971	15,473.04	9,980	13,340	2,133	17.75	120
1972	1,369.67	872	1,166	204	18.18	11
1973	1,726.18	1,084	1,449	277	18.61	15
1974	486.52	301	402	84	19.04	4
1975	909.12	555	742	167	19.48	9
1976	1,641.93	987	1,319	323	19.93	16
1978	1,522.09	888	1,187	335	20.83	16
1981	1,579.82	877	1,172	408	22.24	18
1985	1,166.22	745	996	170	20.64	8
1986	57,181.74	36,133	48,299	8,883	20.68	430
1987	5,760.94	3,578	4,783	978	21.06	46
1989	3,798.31	2,271	3,036	763	21.85	35
1990	1,768.35	1,036	1,385	384	22.26	17
1991	2,041.00	1,170	1,564	477	22.69	21
1992	2,626.45	1,480	1,978	648	22.86	28
1995	422.40	222	297	126	24.01	5
1996	825.00	421	563	262	24.50	11
1997	2,848.85	1,417	1,894	955	24.76	39
1998	2,075.00	1,000	1,337	738	25.28	29
2003	2,542.54	1,030	1,377	1,166	27.16	43
2005	5,268.60	1,956	2,615	2,654	27.95	95
2006	3,944.55	1,394	1,863	2,081	28.36	73
2007	1,852.48	621	830	1,022	28.79	35
2011	2,856.60	735	982	1,874	30.32	62
2012	17,301.02	4,076	5,448	11,853	30.82	385
2016	21,621.02	3,139	4,196	17,425	32.38	538
2017	68,032.91	8,205	10,968	57,065	32.81	1,739

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 375 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 50-S0.5						
NET SALVAGE PERCENT.. 0						
2018	210,544.81	20,128	26,905	183,640	33.13	5,543
2020	11,411.86	484	647	10,765	33.84	318
2021	8,525.00	123	164	8,361	34.10	245
	561,832.66	190,858	242,986	318,847		10,117
	5,554,376.43	2,652,552	3,158,923	2,395,454		89,958

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.6 1.62

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1924	117,709.47	102,713	108,601	9,108	9.30	979
1925	19,822.86	17,232	18,220	1,603	9.54	168
1926	327,554.48	283,626	299,886	27,669	9.79	2,826
1927	31,392.94	27,071	28,623	2,770	10.05	276
1928	128,194.34	110,089	116,400	11,794	10.31	1,144
1929	141,515.81	121,026	127,964	13,552	10.57	1,282
1930	317,573.04	270,417	285,920	31,653	10.84	2,920
1931	182,104.19	154,364	163,213	18,891	11.12	1,699
1932	18,308.89	15,450	16,336	1,973	11.40	173
1933	10,364.50	8,705	9,204	1,160	11.69	99
1934	20,638.67	17,249	18,238	2,401	11.99	200
1935	14,675.65	12,203	12,903	1,773	12.30	144
1936	7,211.17	5,966	6,308	903	12.61	72
1937	10,432.58	8,583	9,075	1,358	12.94	105
1938	7,847.20	6,421	6,789	1,058	13.27	80
1939	20,705.45	16,845	17,811	2,895	13.61	213
1940	20,319.62	16,431	17,373	2,947	13.97	211
1941	31,014.39	24,926	26,355	4,659	14.33	325
1942	29,044.49	23,192	24,522	4,523	14.71	307
1943	4,266.12	3,384	3,578	688	15.10	46
1944	5,530.20	4,356	4,606	924	15.50	60
1945	9,699.44	7,585	8,020	1,680	15.91	106
1946	357,283.69	277,359	293,260	64,024	16.33	3,921
1947	60,291.09	46,440	49,102	11,189	16.77	667
1948	122,822.87	93,850	99,230	23,593	17.22	1,370
1949	137,339.79	104,097	110,065	27,275	17.67	1,544
1950	1,731,633.42	1,301,340	1,375,944	355,689	18.14	19,608
1951	360,256.65	268,316	283,698	76,558	18.63	4,109
1952	668,088.54	493,103	521,372	146,717	19.12	7,673
1953	742,052.55	542,515	573,617	168,436	19.63	8,581
1954	1,390,710.28	1,006,833	1,064,553	326,157	20.15	16,186
1955	1,193,020.29	855,050	904,069	288,951	20.68	13,972
1956	1,779,804.61	1,262,451	1,334,826	444,979	21.22	20,970
1957	1,513,473.00	1,062,125	1,123,015	390,458	21.77	17,936
1958	3,016,196.98	2,093,572	2,213,594	802,603	22.33	35,943
1959	1,811,196.98	1,242,771	1,314,017	497,180	22.91	21,701
1960	2,921,284.43	1,981,274	2,094,858	826,427	23.49	35,182
1961	1,732,095.88	1,160,504	1,227,034	505,062	24.09	20,966
1962	1,887,152.27	1,248,880	1,320,477	566,676	24.69	22,952
1963	2,310,687.20	1,509,549	1,596,089	714,598	25.31	28,234
1964	2,275,704.31	1,467,351	1,551,472	724,232	25.93	27,930
1965	2,879,327.40	1,831,713	1,936,723	942,605	26.56	35,490

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1966	3,012,387.21	1,889,550	1,997,875	1,014,512	27.21	37,285
1967	3,185,324.06	1,969,677	2,082,596	1,102,728	27.86	39,581
1968	3,577,041.94	2,179,563	2,304,514	1,272,528	28.52	44,619
1969	3,953,016.91	2,372,364	2,508,368	1,444,649	29.19	49,491
1970	3,337,246.35	1,971,712	2,084,748	1,252,499	29.87	41,932
1971	3,167,128.09	1,841,717	1,947,300	1,219,828	30.55	39,929
1972	3,071,457.08	1,757,027	1,857,755	1,213,702	31.24	38,851
1973	2,867,355.30	1,612,400	1,704,837	1,162,519	31.95	36,386
1974	3,102,373.68	1,714,806	1,813,113	1,289,260	32.65	39,487
1975	2,235,680.85	1,213,706	1,283,286	952,395	33.37	28,540
1976	1,978,157.46	1,054,121	1,114,552	863,605	34.10	25,326
1977	2,481,264.67	1,297,404	1,371,782	1,109,482	34.83	31,854
1978	2,363,845.04	1,212,369	1,281,872	1,081,973	35.56	30,427
1979	4,441,654.50	2,232,376	2,360,355	2,081,299	36.31	57,320
1980	9,374,077.20	4,615,139	4,879,719	4,494,359	37.06	121,273
1981	6,467,880.77	3,117,001	3,295,694	3,172,186	37.82	83,876
1982	6,939,346.60	3,755,574	3,970,876	2,968,471	33.49	88,638
1983	1,659,533.75	875,238	925,414	734,120	34.50	21,279
1984	2,319,417.02	1,200,298	1,269,109	1,050,308	34.96	30,043
1985	3,040,474.19	1,542,737	1,631,180	1,409,294	35.44	39,766
1986	4,865,928.14	2,400,849	2,538,486	2,327,442	36.45	63,853
1987	2,064,903.15	997,348	1,054,525	1,010,379	36.93	27,359
1988	4,173,377.54	1,971,504	2,084,528	2,088,850	37.42	55,822
1989	3,557,159.82	1,629,891	1,723,330	1,833,829	38.43	47,719
1990	3,312,408.60	1,481,640	1,566,580	1,745,828	38.92	44,857
1991	3,117,134.92	1,359,694	1,437,643	1,679,492	39.43	42,594
1992	2,424,812.39	1,030,060	1,089,112	1,335,700	39.94	33,443
1993	1,063,976.47	436,656	461,689	602,288	40.94	14,711
1994	868,141.87	346,215	366,063	502,079	41.46	12,110
1995	5,076,572.89	1,964,126	2,076,727	2,999,846	41.99	71,442
1996	4,986,565.99	1,856,499	1,962,930	3,023,636	42.99	70,333
1997	1,933,976.91	696,618	736,554	1,197,423	43.52	27,514
1998	2,320,148.63	806,948	853,209	1,466,939	44.07	33,287
1999	1,116,449.00	374,234	395,688	720,761	44.62	16,153
2000	2,569,983.63	823,423	870,629	1,699,355	45.61	37,258
2001	5,871,237.97	1,805,406	1,908,907	3,962,331	46.17	85,820
2002	1,049,992.56	309,118	326,839	723,153	46.73	15,475
2003	3,325,633.23	935,168	988,780	2,336,853	47.29	49,415
2004	1,756,922.59	470,504	497,477	1,259,445	47.86	26,315
2005	1,026,583.17	259,110	273,964	752,619	48.86	15,404
2006	2,690,181.59	642,146	678,959	2,011,222	49.44	40,680
2007	919,241.94	206,646	218,493	700,749	50.01	14,012

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
2008	2,253,682.11	474,625	501,835	1,751,848	50.60	34,622
2009	2,519,327.47	494,292	522,629	1,996,698	51.20	38,998
2010	2,201,175.85	399,954	422,883	1,778,293	51.79	34,337
2011	1,839,025.38	307,117	324,724	1,514,302	52.39	28,904
2012	2,622,059.43	398,553	421,401	2,200,658	53.00	41,522
2013	3,404,256.47	465,702	492,400	2,911,856	53.61	54,316
2014	4,919,884.13	601,210	635,677	4,284,208	53.85	79,558
2015	9,557,487.71	1,018,828	1,077,236	8,480,252	54.48	155,658
2016	12,499,633.61	1,141,217	1,206,641	11,292,992	54.74	206,302
2017	23,582,357.84	1,773,393	1,875,059	21,707,299	55.38	391,970
2018	19,152,521.44	1,139,575	1,204,905	17,947,616	55.32	324,433
2019	10,721,564.07	461,027	487,457	10,234,107	55.64	183,934
2020	11,041,371.78	293,700	310,537	10,730,834	54.99	195,142
2021	24,807,546.93	233,191	246,560	24,560,987	52.97	463,677
	294,154,237.62	92,537,893	97,842,962	196,311,276		4,363,222
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1901	2,788.47	2,636	2,393	395	4.00	99
1903	552.71	519	471	82	4.51	18
1904	358.50	335	304	54	4.76	11
1905	1,658.05	1,545	1,403	255	4.99	51
1906	4,412.89	4,097	3,720	693	5.22	133
1907	11,525.55	10,665	9,682	1,843	5.45	338
1908	23,510.31	21,684	19,686	3,824	5.67	674
1909	467.38	430	390	77	5.89	13
1910	9,231.46	8,459	7,680	1,552	6.11	254
1911	1,085.73	992	901	185	6.32	29
1912	1,092.98	995	903	190	6.54	29
1913	2,417.81	2,194	1,992	426	6.76	63
1914	452.13	409	371	81	6.98	12
1915	192.40	173	157	35	7.20	5
1916	302.63	272	247	56	7.42	8
1917	306.64	275	250	57	7.65	7
1918	1,472.92	1,314	1,193	280	7.88	36
1919	3,179.59	2,826	2,566	614	8.11	76
1920	8,474.93	7,507	6,815	1,660	8.34	199
1921	43,518.50	38,404	34,866	8,653	8.58	1,009

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1922	27,848.23	24,488	22,232	5,616	8.81	637
1923	42,549.44	37,275	33,841	8,709	9.05	962
1924	49,736.78	43,400	39,401	10,335	9.30	1,111
1925	49,311.19	42,867	38,917	10,394	9.54	1,090
1926	13,993.15	12,117	11,001	2,993	9.79	306
1927	37,766.14	32,567	29,566	8,200	10.05	816
1928	10,604.85	9,107	8,268	2,337	10.31	227
1929	2,661.95	2,277	2,067	595	10.57	56
1930	107,397.80	91,450	83,024	24,374	10.84	2,249
1931	237,814.61	201,588	183,015	54,800	11.12	4,928
1932	7,118.00	6,006	5,453	1,665	11.40	146
1933	12,564.08	10,552	9,580	2,984	11.69	255
1934	2,768.95	2,314	2,101	668	11.99	56
1935	3,024.24	2,515	2,283	741	12.30	60
1936	21,819.45	18,050	16,387	5,433	12.61	431
1937	4,389.80	3,612	3,279	1,111	12.94	86
1938	3,643.01	2,981	2,706	937	13.27	71
1939	2,658.83	2,163	1,964	695	13.61	51
1940	12,677.52	10,251	9,307	3,371	13.97	241
1941	6,172.02	4,960	4,503	1,669	14.33	116
1942	5,183.04	4,139	3,758	1,425	14.71	97
1943	1,874.04	1,486	1,349	525	15.10	35
1944	2,366.07	1,864	1,692	674	15.50	43
1945	1,902.91	1,488	1,351	552	15.91	35
1946	74,558.28	57,880	52,547	22,011	16.33	1,348
1947	15,125.48	11,651	10,578	4,548	16.77	271
1948	8,584.41	6,559	5,955	2,630	17.22	153
1949	15,140.94	11,476	10,419	4,722	17.67	267
1950	9,197.22	6,912	6,275	2,922	18.14	161
1951	14,609.87	10,881	9,878	4,731	18.63	254
1952	177,929.36	131,326	119,226	58,703	19.12	3,070
1953	423,593.78	309,689	281,156	142,438	19.63	7,256
1954	7,599.33	5,502	4,995	2,604	20.15	129
1955	105,249.98	75,434	68,484	36,766	20.68	1,778
1956	635,544.43	450,804	409,269	226,276	21.22	10,663
1957	1,599,532.87	1,122,520	1,019,096	580,437	21.77	26,662
1958	178,203.73	123,693	112,296	65,907	22.33	2,952
1959	1,140,921.37	782,855	710,726	430,195	22.91	18,778
1960	637,103.98	432,097	392,285	244,819	23.49	10,422
1961	1,293,682.45	866,767	786,907	506,776	24.09	21,037
1962	1,016,797.69	672,896	610,898	405,900	24.69	16,440
1963	1,797,366.40	1,174,201	1,066,015	731,351	25.31	28,896

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1964	2,991,832.73	1,929,104	1,751,364	1,240,468	25.93	47,839
1965	2,319,604.90	1,475,640	1,339,681	979,924	26.56	36,895
1966	2,082,649.82	1,306,363	1,186,000	896,650	27.21	32,953
1967	2,241,226.72	1,385,885	1,258,195	983,031	27.86	35,285
1968	3,360,582.82	2,047,670	1,859,006	1,501,577	28.52	52,650
1969	3,069,169.92	1,841,932	1,672,224	1,396,946	29.19	47,857
1970	2,484,729.19	1,468,028	1,332,770	1,151,959	29.87	38,566
1971	2,270,265.71	1,320,182	1,198,546	1,071,720	30.55	35,081
1972	3,299,911.31	1,887,714	1,713,788	1,586,124	31.24	50,772
1973	1,216,233.79	683,925	620,911	595,323	31.95	18,633
1974	545,424.93	301,478	273,701	271,724	32.65	8,322
1975	615,365.62	334,070	303,290	312,075	33.37	9,352
1976	409,665.88	218,303	198,189	211,476	34.10	6,202
1977	611,909.55	319,955	290,476	321,434	34.83	9,229
1978	580,670.27	297,814	270,375	310,296	35.56	8,726
1979	1,015,825.10	510,554	463,514	552,311	36.31	15,211
1980	1,099,009.67	541,075	491,223	607,787	37.06	16,400
1981	3,057,727.26	1,473,580	1,337,810	1,719,917	37.82	45,476
1982	4,835,947.84	2,617,215	2,376,076	2,459,872	33.49	73,451
1983	852,250.40	449,477	408,064	444,186	34.50	12,875
1984	1,859,043.37	962,055	873,415	985,628	34.96	28,193
1985	1,834,096.56	930,621	844,877	989,219	35.44	27,912
1986	1,671,956.67	824,943	748,936	923,021	36.45	25,323
1987	2,024,348.41	977,760	887,673	1,136,675	36.93	30,779
1988	1,974,847.41	932,918	846,963	1,127,885	37.42	30,141
1989	1,596,710.86	731,613	664,205	932,506	38.43	24,265
1990	1,292,802.28	578,270	524,991	767,812	38.92	19,728
1991	834,142.30	363,853	330,329	503,813	39.43	12,777
1992	2,819,776.41	1,197,841	1,087,477	1,732,300	39.94	43,373
1993	859,499.04	352,738	320,238	539,261	40.94	13,172
1994	1,535,564.61	612,383	555,961	979,604	41.46	23,628
1995	1,210,666.83	468,407	425,250	785,417	41.99	18,705
1996	8,882,186.50	3,306,838	3,002,160	5,880,027	42.99	136,777
1997	7,744,836.61	2,789,690	2,532,659	5,212,177	43.52	119,765
1998	3,548,192.99	1,234,062	1,120,361	2,427,832	44.07	55,090
1999	442,805.93	148,429	134,753	308,053	44.62	6,904
2000	8,089,316.49	2,591,817	2,353,018	5,736,299	45.61	125,768
2001	2,154,007.46	662,357	601,330	1,552,677	46.17	33,630
2002	5,047,637.11	1,486,024	1,349,108	3,698,529	46.73	79,147
2003	1,733,045.12	487,332	442,431	1,290,614	47.29	27,291
2004	2,013,525.16	539,222	489,540	1,523,985	47.86	31,843
2005	2,724,517.60	687,668	624,309	2,100,209	48.86	42,984

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
2006	1,311,491.42	313,053	284,210	1,027,282	49.44	20,778
2007	914,328.73	205,541	186,603	727,725	50.01	14,552
2008	2,763,759.69	582,048	528,420	2,235,339	50.60	44,177
2009	546,971.21	107,316	97,428	449,543	51.20	8,780
2010	2,404,204.56	436,844	396,595	2,007,610	51.79	38,764
2011	1,323,738.90	221,064	200,696	1,123,043	52.39	21,436
2012	2,646,722.59	402,302	365,236	2,281,487	53.00	43,047
2013	4,760,365.28	651,218	591,217	4,169,148	53.61	77,768
2014	15,726,610.10	1,921,792	1,744,726	13,981,884	53.85	259,645
2015	16,766,641.58	1,787,324	1,622,647	15,143,994	54.48	277,973
2016	11,980,343.88	1,093,805	993,026	10,987,318	54.74	200,718
2017	7,151,184.82	537,769	488,221	6,662,964	55.38	120,314
2018	61,152,211.24	3,638,557	3,303,315	57,848,896	55.32	1,045,714
2019	7,638,493.50	328,455	298,193	7,340,301	55.64	131,925
2020	8,966,770.16	238,516	216,540	8,750,230	54.99	159,124
2021	2,993,758.61	28,141	25,548	2,968,210	52.97	56,036
	259,836,714.67	64,698,941	58,737,847	201,098,868		4,247,427
CPG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1903	542.65	509	543			
1904	278.21	260	278			
1905	17.02	16	17			
1906	175.58	163	176			
1908	16.94	16	17			
1909	59.38	55	59			
1910	474.52	435	475			
1911	4.16	4	4			
1912	75.53	69	76			
1913	941.60	854	942			
1915	258.93	233	259			
1916	85.45	77	85			
1918	100.00	89	100			
1919	146.35	130	146			
1921	55.23	49	55			
1923	9,519.11	8,339	9,369	150	9.05	17
1924	1,060.24	925	1,039	21	9.30	2
1925	6,283.14	5,462	6,137	146	9.54	15

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
1926	4,581.08	3,967	4,457	124	9.79	13
1927	8,190.86	7,063	7,935	255	10.05	25
1928	26,201.23	22,501	25,280	921	10.31	89
1929	90.09	77	87	4	10.57	
1930	197.44	168	189	9	10.84	1
1931	5.86	5	6			
1932	56,310.34	47,517	53,386	2,924	11.40	256
1933	178.90	150	169	10	11.69	1
1934	13.05	11	12	1	11.99	
1935	88.50	74	83	5	12.30	
1936	602.04	498	560	43	12.61	3
1937	1.18	1	1			
1938	77.09	63	71	6	13.27	
1939	363.86	296	333	31	13.61	2
1940	515.84	417	469	47	13.97	3
1941	420.92	338	380	41	14.33	3
1942	981.97	784	881	101	14.71	7
1944	531.32	419	471	61	15.50	4
1945	861.83	674	757	105	15.91	7
1946	4,405.29	3,420	3,842	563	16.33	34
1947	4,382.05	3,375	3,792	590	16.77	35
1948	2,295.39	1,754	1,971	325	17.22	19
1949	66,832.26	50,656	56,913	9,919	17.67	561
1950	1,039.88	781	877	162	18.14	9
1951	20,244.13	15,078	16,940	3,304	18.63	177
1952	5,378.45	3,970	4,460	918	19.12	48
1953	32,142.85	23,500	26,403	5,740	19.63	292
1954	25,767.89	18,655	20,959	4,809	20.15	239
1955	8,846.48	6,340	7,123	1,723	20.68	83
1956	38,417.33	27,250	30,616	7,801	21.22	368
1957	52,040.85	36,521	41,032	11,009	21.77	506
1958	23,071.09	16,014	17,992	5,079	22.33	227
1959	63,826.65	43,795	49,204	14,622	22.91	638
1960	64,150.35	43,508	48,882	15,268	23.49	650
1961	153,880.45	103,100	115,835	38,046	24.09	1,579
1962	216,120.96	143,025	160,691	55,430	24.69	2,245
1963	473,924.11	309,610	347,852	126,072	25.31	4,981
1964	553,303.76	356,765	400,832	152,472	25.93	5,880
1965	345,464.91	219,771	246,917	98,548	26.56	3,710
1966	751,360.25	471,298	529,512	221,848	27.21	8,153
1967	411,774.32	254,625	286,076	125,699	27.86	4,512
1968	544,218.97	331,604	372,563	171,656	28.52	6,019

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

CPG
SURVIVOR CURVE.. IOWA 73-R2.5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1969	464,854.97	278,978	313,437	151,418	29.19	5,187
1970	355,698.32	210,154	236,112	119,587	29.87	4,004
1971	284,872.26	165,656	186,117	98,755	30.55	3,233
1972	158,749.14	90,812	102,029	56,720	31.24	1,816
1973	328,293.37	184,609	207,412	120,882	31.95	3,783
1974	327,217.29	180,866	203,206	124,011	32.65	3,798
1975	119,056.39	64,633	72,616	46,440	33.37	1,392
1976	264,082.92	140,725	158,107	105,976	34.10	3,108
1977	117,664.69	61,525	69,124	48,540	34.83	1,394
1978	357,847.46	183,533	206,203	151,645	35.56	4,264
1979	163,455.84	82,153	92,300	71,155	36.31	1,960
1980	226,156.73	111,344	125,097	101,060	37.06	2,727
1981	259,508.14	125,062	140,509	118,999	37.82	3,146
1982	245,112.69	132,655	149,040	96,072	33.49	2,869
1983	355,853.12	187,677	210,858	144,995	34.50	4,203
1984	139,458.88	72,170	81,084	58,375	34.96	1,670
1985	405,602.23	205,803	231,223	174,379	35.44	4,920
1986	652,744.34	322,064	361,845	290,900	36.45	7,981
1987	152,641.27	73,726	82,832	69,809	36.93	1,890
1988	173,910.98	82,156	92,304	81,607	37.42	2,181
1989	395,645.14	181,285	203,677	191,968	38.43	4,995
1990	89,268.67	39,930	44,862	44,407	38.92	1,141
1991	536,756.61	234,133	263,053	273,704	39.43	6,942
1992	1,309,325.71	556,202	624,903	684,423	39.94	17,136
1993	701,948.74	288,080	323,663	378,286	40.94	9,240
1995	2,002.38	775	871	1,132	41.99	27
1996	515,042.15	191,750	215,435	299,608	42.99	6,969
1997	771,380.50	277,851	312,171	459,210	43.52	10,552
1998	1,034,222.00	359,702	404,132	630,090	44.07	14,297
1999	389,364.61	130,515	146,636	242,729	44.62	5,440
2000	3,615,397.22	1,158,373	1,301,453	2,313,944	45.61	50,733
2001	449,734.05	138,293	155,375	294,359	46.17	6,376
2002	1,551,586.85	456,787	513,208	1,038,378	46.73	22,221
2003	356,970.29	100,380	112,779	244,192	47.29	5,164
2004	4,260,798.19	1,141,042	1,281,981	2,978,817	47.86	62,240
2005	6,363,029.64	1,606,029	1,804,402	4,558,627	48.86	93,300
2006	2,596,001.70	619,666	696,206	1,899,796	49.44	38,426
2007	1,045,561.02	235,042	264,074	781,487	50.01	15,627
2008	168,541.62	35,495	39,879	128,662	50.60	2,543
2009	3,191,548.84	626,182	703,527	2,488,022	51.20	48,594
2010	953,805.62	173,306	194,712	759,093	51.79	14,657
2011	2,263,978.57	378,084	424,784	1,839,194	52.39	35,106

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.1 MAINS - PRIMARILY STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 73-R2.5						
NET SALVAGE PERCENT.. 0						
2012	504,910.56	76,746	86,226	418,685	53.00	7,900
2013	946,677.52	129,505	145,501	801,176	53.61	14,945
2014	488,857.58	59,738	67,117	421,741	53.85	7,832
2015	2,367,156.30	252,339	283,507	2,083,649	54.48	38,246
2016	9,569,265.35	873,674	981,588	8,587,677	54.74	156,881
2017	7,613,323.66	572,522	643,239	6,970,085	55.38	125,859
2018	5,202,731.21	309,563	347,800	4,854,932	55.32	87,761
2019	4,083,589.38	175,594	197,283	3,886,306	55.64	69,847
2020	10,225,173.01	271,990	305,586	9,919,587	54.99	180,389
2021	69,974.13	658	739	69,235	52.97	1,307
	83,169,545.96	17,194,655	19,318,410	63,851,136		1,269,632
	637,160,498.25	174,431,489	175,899,218	461,261,280		9,880,281

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.7 1.55

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1872	70.19	70	70			
1873	2.09	2	2			
1874	80.00	80	80			
1875	395.49	395	395			
1876	93.03	93	93			
1878	13.45	13	13			
1881	925.13	925	925			
1882	85.56	86	86			
1883	34.29	34	34			
1884	969.80	970	970			
1885	115.70	116	116			
1886	549.89	550	550			
1887	1,105.75	1,106	1,106			
1888	139.00	139	139			
1889	1,391.07	1,391	1,391			
1890	1,736.95	1,737	1,737			
1891	1,096.11	1,095	113	983	0.07	983
1893	121.53	120	12	109	0.72	109
1894	198.24	195	20	178	1.04	171
1895	1,935.48	1,895	195	1,740	1.37	1,270
1896	1,594.48	1,553	160	1,434	1.71	839
1897	1,155.05	1,119	115	1,040	2.04	510
1898	589.91	568	59	531	2.37	224
1899	21,507.86	20,628	2,126	19,382	2.66	7,286
1901	6,492.38	6,178	637	5,856	3.15	1,859
1902	3,076.10	2,918	301	2,775	3.34	831
1903	5,567.49	5,268	543	5,025	3.50	1,436
1904	3,174.62	2,997	309	2,866	3.63	790
1905	4,557.58	4,295	443	4,115	3.75	1,097
1906	5,292.68	4,979	513	4,780	3.85	1,242
1907	2,874.11	2,699	278	2,596	3.95	657
1908	8,696.40	8,157	841	7,856	4.03	1,949
1909	5,596.34	5,241	540	5,056	4.12	1,227
1910	10,465.56	9,790	1,009	9,457	4.19	2,257
1911	8,517.05	7,957	820	7,697	4.27	1,803
1912	16,093.21	15,016	1,548	14,546	4.34	3,352
1913	2,054.48	1,915	197	1,857	4.40	422
1914	7,492.64	6,976	719	6,774	4.47	1,515
1915	17,108.58	15,914	1,640	15,468	4.52	3,422
1916	13,616.49	12,653	1,304	12,312	4.58	2,688
1917	8,362.39	7,764	800	7,562	4.63	1,633

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1918	8,062.01	7,478	771	7,291	4.68	1,558
1919	22,853.31	21,178	2,183	20,671	4.73	4,370
1920	22,062.00	20,426	2,105	19,957	4.78	4,175
1921	23,942.14	22,150	2,283	21,659	4.82	4,494
1922	51,085.01	47,225	4,867	46,218	4.86	9,510
1923	32,339.13	29,872	3,079	29,260	4.90	5,971
1924	107,475.23	99,196	10,224	97,252	4.94	19,687
1925	36,868.64	34,007	3,505	33,364	4.97	6,713
1926	70,742.92	65,197	6,719	64,023	5.01	12,779
1927	46,117.97	42,474	4,378	41,740	5.04	8,282
1928	37,339.21	34,365	3,542	33,797	5.07	6,666
1929	65,340.54	60,094	6,194	59,147	5.10	11,597
1930	29,030.39	26,680	2,750	26,281	5.13	5,123
1931	5,361.27	4,924	507	4,854	5.16	941
1932	3,800.37	3,488	359	3,441	5.18	664
1933	187.86	172	18	170	5.21	33
1934	550.57	505	52	499	5.23	95
1935	4,268.84	3,909	403	3,866	5.26	735
1936	7,078.28	6,478	668	6,411	5.28	1,214
1937	3,830.75	3,503	361	3,470	5.30	655
1938	3,376.81	3,086	318	3,059	5.32	575
1939	13,021.51	11,892	1,226	11,796	5.34	2,209
1940	8,011.21	7,310	753	7,258	5.36	1,354
1941	18,910.15	17,243	1,777	17,133	5.38	3,185
1942	673.78	614	63	610	5.40	113
1943	1,255.33	1,143	118	1,138	5.42	210
1944	3,629.16	3,301	340	3,289	5.43	606
1945	407.77	371	38	370	5.45	68
1946	9,975.36	9,060	934	9,042	5.46	1,656
1947	18,280.28	16,587	1,710	16,571	5.48	3,024
1948	32,806.04	29,738	3,065	29,741	5.50	5,407
1949	21,664.54	19,622	2,022	19,642	5.51	3,565
1950	48,354.42	43,758	4,510	43,845	5.52	7,943
1951	48,144.49	43,520	4,485	43,659	5.54	7,881
1952	63,374.13	57,234	5,899	57,475	5.55	10,356
1953	97,351.84	87,834	9,052	88,299	5.56	15,881
1954	56,910.22	51,285	5,286	51,625	5.58	9,252
1955	71,657.90	64,506	6,648	65,010	5.59	11,630
1956	84,054.52	75,584	7,790	76,265	5.60	13,619
1957	89,916.66	80,763	8,324	81,593	5.61	14,544
1958	72,404.37	64,957	6,695	65,710	5.62	11,692

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.2 MAINS - CAST IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1959	79,794.48	71,498	7,369	72,426	5.63	12,864
1960	6,343.84	5,677	585	5,759	5.64	1,021
1961	53.38	48	5	48	5.65	8
1962	3,643.02	3,251	335	3,308	5.66	584
1968	316.24	280	29	287	5.72	50
2012	6,038.58	3,729	384	5,654	5.88	962
2015	125.58	66	7	119	5.88	20
2016	9,583.14	4,638	478	9,105	5.86	1,554
2019	395,280.57	118,584	12,222	383,059	5.83	65,705
2020	63,352.19	13,013	1,341	62,011	5.80	10,692
	2,071,992.10	1,599,110	171,723	1,900,269		363,064
PNG						
INTERIM SURVIVOR CURVE.. IOWA 65-R1						
PROBABLE RETIREMENT YEAR.. 9-2027						
NET SALVAGE PERCENT.. 0						
1903	827.90	783	711	117	3.50	33
1904	1,600.92	1,512	1,373	228	3.63	63
1905	59.45	56	51	9	3.75	2
1906	3,388.02	3,187	2,893	495	3.85	129
1908	45.16	42	38	7	4.03	2
1910	2,040.42	1,909	1,733	307	4.19	73
1911	14,153.98	13,223	12,005	2,149	4.27	503
1912	6,872.13	6,412	5,821	1,051	4.34	242
1923	297.99	275	250	48	4.90	10
1943	508.36	463	420	88	5.42	16
1952	86,725.74	78,323	71,107	15,619	5.55	2,814
	116,520.07	106,185	96,402	20,118		3,887
	2,188,512.17	1,705,295	268,125	1,920,387		366,951

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 16.77

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1972	23,054.83	14,865	14,975	8,080	23.80	339
1973	52,646.57	33,395	33,642	19,005	24.50	776
1974	12,648.66	7,889	7,947	4,701	25.21	186
1975	50,104.46	30,721	30,948	19,156	25.92	739
1976	530,869.88	319,711	322,074	208,795	26.65	7,835
1977	478,647.82	282,972	285,064	193,584	27.39	7,068
1978	709,716.60	411,742	414,786	294,931	28.13	10,485
1979	560,057.51	318,566	320,921	239,137	28.89	8,278
1980	1,197,733.71	667,689	672,625	525,109	29.65	17,710
1981	1,483,743.75	810,080	816,068	667,675	30.42	21,949
1982	2,099,604.22	1,227,429	1,236,503	863,102	28.07	30,748
1983	2,485,646.00	1,425,767	1,436,307	1,049,339	28.62	36,665
1984	3,426,270.64	1,927,277	1,941,524	1,484,746	29.17	50,900
1985	3,562,467.41	1,950,451	1,964,869	1,597,598	30.17	52,953
1986	4,515,518.93	2,420,318	2,438,210	2,077,309	30.73	67,599
1987	7,776,997.39	4,078,257	4,108,405	3,668,592	31.29	117,245
1988	11,005,942.32	5,641,646	5,683,351	5,322,591	31.86	167,062
1989	13,440,287.56	6,682,511	6,731,911	6,708,377	32.86	204,150
1990	15,159,126.58	7,353,692	7,408,053	7,751,073	33.44	231,790
1991	9,128,591.13	4,315,998	4,347,904	4,780,688	34.01	140,567
1992	7,152,846.80	3,270,282	3,294,457	3,858,390	35.02	110,177
1993	5,291,217.42	2,352,475	2,369,865	2,921,352	35.60	82,060
1994	9,541,465.74	4,120,005	4,150,462	5,391,004	36.19	148,964
1995	15,396,617.47	6,404,993	6,452,341	8,944,276	37.20	240,438
1996	9,403,104.70	3,788,511	3,816,517	5,586,588	37.79	147,832
1997	14,205,842.65	5,499,082	5,539,733	8,666,109	38.79	223,411
1998	10,002,738.94	3,737,023	3,764,649	6,238,090	39.40	158,327
1999	10,572,365.38	3,806,052	3,834,188	6,738,178	40.00	168,454
2000	11,014,039.88	3,788,830	3,816,838	7,197,201	41.00	175,541
2001	11,107,014.80	3,665,315	3,692,410	7,414,604	41.61	178,193
2002	10,224,124.42	3,229,801	3,253,677	6,970,447	42.23	165,059
2003	14,393,971.79	4,313,873	4,345,763	10,048,209	43.23	232,436
2004	13,422,241.52	3,828,023	3,856,321	9,565,920	43.85	218,151
2005	14,404,810.86	3,874,894	3,903,539	10,501,272	44.85	234,142
2006	15,071,313.53	3,831,128	3,859,449	11,211,864	45.48	246,523
2007	14,208,813.17	3,378,856	3,403,834	10,804,979	46.48	232,465
2008	12,042,691.62	2,683,112	2,702,947	9,339,745	47.10	198,296
2009	11,591,705.02	2,405,279	2,423,060	9,168,645	47.74	192,054
2010	12,037,270.16	2,297,915	2,314,902	9,722,368	48.74	199,474
2011	16,863,578.50	2,957,872	2,979,738	13,883,841	49.38	281,163
2012	22,448,083.79	3,560,266	3,586,585	18,861,499	50.38	374,385
2013	30,112,477.82	4,300,062	4,331,850	25,780,628	51.02	505,304

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)

UGI-GAS
SURVIVOR CURVE.. IOWA 67-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2014	33,458,848.14	4,215,815	4,246,980	29,211,868	52.02	561,551
2015	31,763,778.48	3,487,663	3,513,445	28,250,333	52.67	536,365
2016	44,412,148.02	4,152,536	4,183,233	40,228,915	53.32	754,481
2017	39,848,435.03	3,068,329	3,091,011	36,757,424	53.98	680,945
2018	51,507,192.84	3,080,130	3,102,900	48,404,293	54.98	880,398
2019	73,686,925.18	3,168,538	3,191,961	70,494,964	55.64	1,266,984
2020	61,256,139.83	1,598,785	1,610,604	59,645,536	55.97	1,065,670
2021	55,013,527.78	484,119	487,698	54,525,830	56.00	973,676
	759,155,007.25	144,270,540	145,337,043	613,817,964		12,607,963

PNG
SURVIVOR CURVE.. IOWA 67-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1973	372,688.95	236,408	258,222	114,467	24.50	4,672
1974	579,420.80	361,402	394,749	184,672	25.21	7,325
1975	1,621,789.71	994,368	1,086,119	535,670	25.92	20,666
1976	1,106,114.39	666,146	727,612	378,502	26.65	14,203
1977	1,361,413.46	804,854	879,119	482,295	27.39	17,608
1978	1,775,771.78	1,030,214	1,125,273	650,499	28.13	23,125
1979	1,952,927.54	1,110,845	1,213,344	739,584	28.89	25,600
1980	2,096,805.76	1,168,885	1,276,739	820,067	29.65	27,658
1981	1,540,951.52	841,313	918,942	622,010	30.42	20,447
1982	1,566,337.52	915,681	1,000,172	566,166	28.07	20,170
1983	811,765.21	465,629	508,593	303,172	28.62	10,593
1984	1,033,786.42	581,505	635,161	398,625	29.17	13,666
1985	1,302,113.17	712,907	778,688	523,426	30.17	17,349
1986	2,002,671.24	1,073,432	1,172,479	830,193	30.73	27,016
1987	3,257,041.58	1,707,993	1,865,591	1,391,450	31.29	44,469
1988	5,844,935.14	2,996,114	3,272,569	2,572,367	31.86	80,740
1989	4,349,838.04	2,162,739	2,362,297	1,987,541	32.86	60,485
1990	4,809,235.09	2,332,960	2,548,225	2,261,010	33.44	67,614
1991	2,261,706.38	1,069,335	1,168,004	1,093,703	34.01	32,158
1992	2,738,890.69	1,252,221	1,367,765	1,371,126	35.02	39,153
1993	2,662,524.47	1,183,758	1,292,985	1,369,540	35.60	38,470
1994	5,392,575.20	2,328,514	2,543,368	2,849,207	36.19	78,729
1995	5,675,495.91	2,361,006	2,578,858	3,096,637	37.20	83,243
1996	6,600,932.92	2,659,516	2,904,912	3,696,021	37.79	97,804
1997	10,033,496.52	3,883,967	4,242,345	5,791,152	38.79	149,295
1998	7,503,199.52	2,803,195	3,061,849	4,441,351	39.40	112,725

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1999	5,250,051.05	1,890,018	2,064,412	3,185,639	40.00	79,641
2000	4,081,274.90	1,403,959	1,533,504	2,547,771	41.00	62,141
2001	7,182,288.45	2,370,155	2,588,852	4,593,437	41.61	110,393
2002	3,226,824.32	1,019,354	1,113,411	2,113,413	42.23	50,045
2003	4,344,927.35	1,302,175	1,422,328	2,922,599	43.23	67,606
2004	8,756,983.53	2,497,492	2,727,938	6,029,045	43.85	137,492
2005	6,607,601.14	1,777,445	1,941,452	4,666,149	44.85	104,039
2006	3,985,954.85	1,013,230	1,106,722	2,879,233	45.48	63,308
2007	5,613,661.45	1,334,929	1,458,104	4,155,557	46.48	89,405
2008	4,657,758.73	1,037,749	1,133,503	3,524,256	47.10	74,825
2009	5,602,881.63	1,162,598	1,269,872	4,333,010	47.74	90,763
2010	4,099,628.92	782,619	854,832	3,244,797	48.74	66,574
2011	5,592,679.26	980,956	1,071,470	4,521,209	49.38	91,560
2012	8,994,482.04	1,426,525	1,558,152	7,436,330	50.38	147,605
2013	5,734,753.34	818,923	894,486	4,840,267	51.02	94,870
2014	8,105,349.69	1,021,274	1,115,508	6,989,842	52.02	134,368
2015	15,606,759.20	1,713,622	1,871,740	13,735,020	52.67	260,775
2016	18,083,721.32	1,690,828	1,846,842	16,236,879	53.32	304,518
2017	21,058,673.89	1,621,518	1,771,137	19,287,537	53.98	357,309
2018	22,684,261.85	1,356,519	1,481,686	21,202,575	54.98	385,642
2019	27,299,512.33	1,173,879	1,282,194	26,017,318	55.64	467,601
2020	17,358,810.40	453,065	494,870	16,863,941	55.97	301,303
2021	18,729,098.26	164,816	180,024	18,549,075	56.00	331,233
	312,912,366.83	67,718,555	73,967,016	238,945,351		5,007,999
CPG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
1951	1,200.01	986	1,108	92	11.96	8
1967	8,011.27	5,564	6,251	1,760	20.47	86
1968	14,835.34	10,161	11,416	3,419	21.11	162
1969	12,242.06	8,264	9,285	2,957	21.77	136
1970	26,751.63	17,792	19,990	6,762	22.44	301
1971	378,187.80	247,739	278,338	99,850	23.11	4,321
1972	588,821.15	379,660	426,553	162,268	23.80	6,818
1973	469,618.31	297,893	334,687	134,932	24.50	5,507
1974	660,779.57	412,148	463,053	197,726	25.21	7,843
1975	609,963.68	373,987	420,179	189,785	25.92	7,322
1976	373,178.45	224,743	252,502	120,677	26.65	4,528

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

CPG
SURVIVOR CURVE.. IOWA 67-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1977	670,412.80	396,341	445,294	225,119	27.39	8,219
1978	556,795.52	323,025	362,923	193,873	28.13	6,892
1979	507,546.82	288,698	324,356	183,191	28.89	6,341
1980	754,068.82	420,363	472,283	281,786	29.65	9,504
1981	863,433.57	471,409	529,634	333,800	30.42	10,973
1982	776,449.34	453,912	509,976	266,474	28.07	9,493
1983	901,106.62	516,875	580,716	320,391	28.62	11,195
1984	1,435,081.80	807,234	906,938	528,144	29.17	18,106
1985	1,629,400.33	892,097	1,002,282	627,118	30.17	20,786
1986	1,923,715.15	1,031,111	1,158,466	765,249	30.73	24,902
1987	1,508,715.07	791,170	888,889	619,826	31.29	19,809
1988	2,150,994.23	1,102,600	1,238,785	912,209	31.86	28,632
1989	2,229,752.17	1,108,633	1,245,563	984,189	32.86	29,951
1990	2,339,387.42	1,134,837	1,275,004	1,064,384	33.44	31,830
1991	2,762,154.55	1,305,947	1,467,248	1,294,907	34.01	38,074
1992	2,205,441.87	1,008,328	1,132,869	1,072,573	35.02	30,627
1993	3,452,220.52	1,534,857	1,724,431	1,727,789	35.60	48,533
1994	3,522,157.58	1,520,868	1,708,714	1,813,443	36.19	50,109
1995	3,864,017.28	1,607,431	1,805,969	2,058,048	37.20	55,324
1996	4,801,159.48	1,934,387	2,173,308	2,627,851	37.79	69,538
1997	4,926,696.27	1,907,124	2,142,678	2,784,019	38.79	71,772
1998	5,738,760.89	2,144,001	2,408,812	3,329,949	39.40	84,516
1999	3,421,597.48	1,231,775	1,383,915	2,037,683	40.00	50,942
2000	4,980,645.39	1,713,342	1,924,961	3,055,684	41.00	74,529
2001	2,528,321.91	834,346	937,398	1,590,924	41.61	38,234
2002	4,200,092.71	1,326,809	1,490,687	2,709,406	42.23	64,158
2003	4,419,998.48	1,324,674	1,488,288	2,931,711	43.23	67,817
2004	4,638,200.53	1,322,815	1,486,199	3,152,001	43.85	71,881
2005	4,756,965.31	1,279,624	1,437,674	3,319,292	44.85	74,009
2006	6,371,799.78	1,619,712	1,819,767	4,552,033	45.48	100,089
2007	5,432,006.29	1,291,731	1,451,276	3,980,730	46.48	85,644
2008	4,932,696.08	1,099,005	1,234,746	3,697,950	47.10	78,513
2009	4,355,051.60	903,673	1,015,288	3,339,764	47.74	69,957
2010	6,237,980.99	1,190,831	1,337,914	4,900,067	48.74	100,535
2011	7,186,933.44	1,260,588	1,416,286	5,770,647	49.38	116,862
2012	5,196,175.59	824,113	925,901	4,270,274	50.38	84,761
2013	5,563,318.72	794,442	892,566	4,670,753	51.02	91,547
2014	7,540,947.58	950,159	1,067,516	6,473,432	52.02	124,441
2015	14,041,635.99	1,541,772	1,732,200	12,309,436	52.67	233,709
2016	12,532,456.46	1,171,785	1,316,515	11,215,941	53.32	210,351
2017	13,241,581.79	1,019,602	1,145,536	12,096,046	53.98	224,084
2018	16,674,863.04	997,157	1,120,318	15,554,545	54.98	282,913

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.3 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 67-R3						
NET SALVAGE PERCENT.. 0						
2019	7,899,056.68	339,659	381,611	7,517,446	55.64	135,109
2020	4,710,481.37	122,944	138,129	4,572,352	55.97	81,693
2021	11,552,424.64	101,661	114,217	11,438,207	56.00	204,254
	215,078,289.22	48,942,404	54,987,404	160,090,886		3,388,190
	1,287,145,663.30	260,931,499	274,291,463	1,012,854,201		21,004,152

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.2 1.63

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1857	340.82	341	341			
1858	2.19	2	2			
1859	148.27	148	148			
1866	31.45	31	31			
1867	17.63	18	18			
1868	5.30	5	5			
1869	14.18	14	14			
1872	45.78	46	46			
1873	24.59	25	25			
1874	1.83	2	2			
1878	2.43	2	2			
1879	910.61	911	911			
1880	229.23	229	229			
1881	506.05	505	506			
1882	81.10	81	81			
1885	2.33	2	2			
1887	54.70	53	55			
1888	230.23	222	230			
1889	30.19	29	30			
1890	191.30	183	191			
1891	7.56	7	7			
1893	226.47	213	226			
1894	1.17	1	1			
1895	64.19	60	64			
1896	200.16	186	198	3	4.96	1
1897	70.07	65	69	1	5.26	
1898	236.68	218	232	5	5.56	1
1899	1,151.04	1,055	1,121	30	5.86	5
1901	1,823.44	1,655	1,758	65	6.45	10
1902	858.12	775	823	35	6.75	5
1903	2,783.58	2,504	2,660	124	7.04	18
1904	6,859.36	6,141	6,524	336	7.33	46
1905	2,828.98	2,521	2,678	151	7.62	20
1906	4,634.90	4,112	4,368	267	7.90	34
1907	3,011.94	2,660	2,826	186	8.17	23
1908	6,470.50	5,690	6,044	426	8.44	50
1909	6,566.28	5,750	6,108	458	8.70	53
1910	9,002.43	7,850	8,339	663	8.96	74
1911	19,368.44	16,819	17,867	1,502	9.21	163
1912	12,488.38	10,799	11,472	1,017	9.46	108
1913	19,952.20	17,185	18,256	1,697	9.70	175

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.5 MAINS - PRIMARILY WROUGHT IRON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1914	52,379.23	44,933	47,732	4,647	9.94	468
1915	24,228.79	20,704	21,994	2,235	10.17	220
1916	19,636.02	16,714	17,755	1,881	10.40	181
1917	3,879.82	3,290	3,495	385	10.62	36
1918	4,097.87	3,462	3,678	420	10.84	39
1919	5,274.03	4,439	4,716	559	11.05	51
1920	2,322.08	1,947	2,068	254	11.26	23
1921	9,356.23	7,818	8,305	1,051	11.46	92
1922	14,230.62	11,849	12,587	1,643	11.66	141
1923	14,826.56	12,300	13,066	1,760	11.86	148
1924	43,232.64	35,742	37,969	5,264	12.05	437
	294,939.99	252,313	267,875	27,065		2,622
PNG						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 9-2041						
NET SALVAGE PERCENT.. 0						
1904	1,183.84	1,060	962	221	7.33	30
1906	505.47	448	407	99	7.90	13
1911	733.05	637	578	155	9.21	17
1912	2,886.54	2,496	2,266	620	9.46	66
1914	339.20	291	264	75	9.94	8
1915	4,350.95	3,718	3,375	975	10.17	96
1916	121.20	103	94	28	10.40	3
1923	147.85	123	112	36	11.86	3
1924	17.25	14	13	5	12.05	
1928	52.02	42	38	14	12.76	1
1939	125.74	99	90	36	14.42	2
1940	30.00	24	22	8	14.55	1
1943	25.03	19	17	8	14.92	1
	10,518.14	9,074	8,238	2,280		241
	305,458.13	261,387	276,113	29,345		2,863

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.2 0.94

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 376.7 REG AFUDC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2021	1,322,088.00	132,209	134,963	1,187,125	4.50	263,806
	1,322,088.00	132,209	134,963	1,187,125		263,806

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5   19.95

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1910	60.11	60	60			
1916	181.38	181	181			
1919	866.04	866	866			
1920	206.24	206	206			
1921	61.35	61	61			
1923	344.32	344	344			
1924	964.73	965	965			
1926	1,128.81	1,129	1,129			
1927	2,475.31	2,475	2,475			
1928	46.54	46	47			
1929	648.47	641	648			
1930	760.31	745	760			
1931	2,359.80	2,296	2,360			
1935	52.66	50	52	1	2.76	
1936	389.94	364	376	14	3.13	4
1937	1,324.03	1,225	1,266	58	3.51	17
1940	177.98	160	165	13	4.63	3
1941	67.66	60	62	6	5.01	1
1942	2,251.19	1,993	2,060	191	5.39	35
1943	951.02	834	862	89	5.77	15
1945	662.30	570	589	73	6.54	11
1946	836.20	713	737	99	6.92	14
1947	2,582.50	2,181	2,254	328	7.31	45
1948	1,731.51	1,448	1,497	235	7.70	31
1949	1,284.38	1,063	1,099	186	8.09	23
1950	12,348.68	10,121	10,462	1,887	8.48	223
1951	9,097.79	7,381	7,629	1,468	8.87	166
1952	18,233.00	14,637	15,130	3,103	9.27	335
1953	16,010.31	12,720	13,148	2,862	9.66	296
1954	58,460.58	45,948	47,494	10,966	10.06	1,090
1955	21,916.49	17,039	17,612	4,304	10.46	411
1956	93,634.68	71,999	74,422	19,213	10.86	1,769
1957	22,718.71	17,271	17,852	4,867	11.27	432
1958	34,439.52	25,888	26,759	7,680	11.67	658
1959	4,247.36	3,156	3,262	985	12.08	82
1960	30,885.78	22,678	23,441	7,445	12.49	596
1961	35,479.51	25,741	26,607	8,872	12.90	688
1962	39,510.06	28,321	29,274	10,236	13.31	769
1963	23,683.58	16,765	17,329	6,354	13.73	463
1964	17,515.14	12,242	12,654	4,861	14.15	344
1965	12,598.78	8,693	8,986	3,613	14.57	248
1966	23,234.84	15,824	16,356	6,878	14.99	459

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1967	50,058.92	33,646	34,778	15,281	15.41	992
1968	37,129.12	24,616	25,444	11,685	15.84	738
1969	26,218.37	17,142	17,719	8,500	16.27	522
1970	35,888.36	23,137	23,916	11,973	16.70	717
1971	179,160.05	113,824	117,654	61,506	17.14	3,588
1972	52,486.52	32,854	33,959	18,527	17.58	1,054
1973	11,695.29	7,211	7,454	4,242	18.02	235
1974	61,322.33	37,237	38,490	22,832	18.46	1,237
1975	44,847.84	26,804	27,706	17,142	18.91	907
1976	70,074.81	41,210	42,597	27,478	19.36	1,419
1977	29,085.96	16,827	17,393	11,693	19.81	590
1978	35,308.33	20,081	20,757	14,552	20.27	718
1979	33,031.61	18,463	19,084	13,947	20.73	673
1980	104,150.59	57,172	59,096	45,055	21.20	2,125
1981	179,956.67	97,024	100,289	79,668	21.66	3,678
1982	171,508.31	115,837	119,735	51,774	18.98	2,728
1983	36,280.59	24,163	24,976	11,305	19.31	585
1984	82,719.21	54,280	56,106	26,613	19.65	1,354
1985	182,636.27	117,983	121,953	60,683	20.00	3,034
1986	198,465.24	126,105	130,348	68,117	20.37	3,344
1987	148,175.08	92,521	95,634	52,541	20.75	2,532
1988	156,311.04	95,819	99,043	57,268	21.15	2,708
1989	338,101.06	204,382	211,259	126,842	21.26	5,966
1990	138,197.78	81,841	84,595	53,603	21.69	2,471
1991	195,436.44	113,861	117,692	77,744	21.85	3,558
1992	285,466.97	162,545	168,014	117,453	22.31	5,265
1993	87,332.58	48,784	50,426	36,907	22.52	1,639
1994	182,839.56	99,556	102,906	79,934	23.01	3,474
1995	400,287.88	213,193	220,367	179,921	23.25	7,739
1996	918,457.28	477,781	493,858	424,600	23.52	18,053
1997	297,001.05	150,639	155,708	141,293	23.81	5,934
1998	507,766.75	250,583	259,015	248,752	24.12	10,313
1999	147,679.71	70,768	73,149	74,530	24.45	3,048
2000	651,311.57	303,902	314,128	337,184	24.58	13,718
2001	425,833.59	192,051	198,513	227,320	24.95	9,111
2002	262,462.50	114,644	118,502	143,961	25.14	5,726
2003	2,217,243.86	931,242	962,577	1,254,667	25.55	49,106
2004	1,213,633.44	490,551	507,057	706,576	25.79	27,397
2005	896,588.50	347,697	359,397	537,192	26.05	20,622
2006	871,629.05	322,851	333,715	537,915	26.34	20,422
2007	742,517.91	261,663	270,468	472,050	26.65	17,713
2008	1,493,555.03	500,042	516,868	976,687	26.82	36,416

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
2009	548,062.67	173,297	179,128	368,934	27.03	13,649
2010	585,387.03	173,684	179,528	405,859	27.26	14,888
2011	2,505,792.80	692,100	715,388	1,790,404	27.52	65,058
2012	2,440,498.11	621,351	642,259	1,798,239	27.81	64,662
2013	927,942.84	216,118	223,390	704,553	28.00	25,163
2014	1,517,749.53	318,727	329,452	1,188,298	28.21	42,123
2015	5,070,616.34	946,177	978,015	4,092,602	28.34	144,411
2016	3,676,083.96	594,423	614,425	3,061,659	28.51	107,389
2017	3,167,047.86	430,402	444,885	2,722,163	28.61	95,147
2018	1,753,126.95	190,214	196,614	1,556,512	28.76	54,121
2019	5,168,869.13	413,510	427,424	4,741,445	28.75	164,920
2020	2,512,563.32	124,372	128,557	2,384,006	28.80	82,778
2021	5,829,040.27	100,259	103,633	5,725,408	28.57	200,399
	50,399,063.42	11,904,266	12,304,582	38,094,482		1,387,105
PNG						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1929	62.39	62	62			
1930	110.70	109	101	10	0.92	10
1932	198.75	192	178	21	1.65	13
1952	2,329.83	1,870	1,735	595	9.27	64
1953	1,161.22	923	856	305	9.66	32
1954	1,184.67	931	864	321	10.06	32
1955	9,020.40	7,013	6,505	2,515	10.46	240
1956	489.68	377	350	140	10.86	13
1957	73,352.05	55,763	51,726	21,626	11.27	1,919
1958	56,853.89	42,737	39,643	17,211	11.67	1,475
1959	12,832.66	9,534	8,844	3,989	12.08	330
1960	32,622.98	23,954	22,220	10,403	12.49	833
1961	23,824.55	17,285	16,034	7,791	12.90	604
1962	27,434.39	19,665	18,241	9,193	13.31	691
1963	57,606.75	40,778	37,826	19,781	13.73	1,441
1964	58,479.46	40,874	37,915	20,564	14.15	1,453
1965	115,288.20	79,549	73,790	41,498	14.57	2,848
1966	93,669.79	63,795	59,177	34,493	14.99	2,301
1967	110,164.83	74,045	68,685	41,480	15.41	2,692
1968	158,467.22	105,061	97,455	61,012	15.84	3,852
1969	420,422.42	274,885	254,985	165,437	16.27	10,168

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

PNG
SURVIVOR CURVE.. IOWA 47-S0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1970	357,141.46	230,242	213,574	143,567	16.70	8,597
1971	177,034.25	112,473	104,331	72,703	17.14	4,242
1972	61,924.75	38,762	35,956	25,969	17.58	1,477
1973	160,168.83	98,760	91,611	68,558	18.02	3,805
1974	60,341.95	36,641	33,988	26,353	18.46	1,428
1975	28,121.60	16,807	15,590	12,531	18.91	663
1976	50,283.75	29,571	27,430	22,853	19.36	1,180
1977	213,534.89	123,532	114,589	98,946	19.81	4,995
1978	8,203.40	4,665	4,327	3,876	20.27	191
1979	28,407.30	15,878	14,729	13,679	20.73	660
1980	113,721.31	62,426	57,907	55,814	21.20	2,633
1981	456,372.00	246,053	228,241	228,131	21.66	10,532
1982	329,811.92	222,755	206,629	123,183	18.98	6,490
1983	225,068.98	149,896	139,045	86,024	19.31	4,455
1984	56,272.69	36,926	34,253	22,020	19.65	1,121
1985	104,584.42	67,562	62,671	41,913	20.00	2,096
1986	133,483.26	84,815	78,675	54,808	20.37	2,691
1987	262,566.66	163,947	152,078	110,488	20.75	5,325
1988	120,169.63	73,664	68,331	51,838	21.15	2,451
1989	200,959.40	121,480	112,686	88,274	21.26	4,152
1990	106,581.06	63,117	58,548	48,033	21.69	2,215
1991	79,951.77	46,580	43,208	36,744	21.85	1,682
1992	148,014.46	84,279	78,178	69,837	22.31	3,130
1993	179,613.22	100,332	93,069	86,545	22.52	3,843
1994	426,429.44	232,191	215,382	211,047	23.01	9,172
1995	295,771.47	157,528	146,124	149,647	23.25	6,436
1996	198,837.25	103,435	95,947	102,890	23.52	4,375
1997	426,703.61	216,424	200,757	225,947	23.81	9,490
1998	449,206.85	221,684	205,636	243,571	24.12	10,098
1999	143,642.05	68,833	63,850	79,792	24.45	3,263
2000	131,131.51	61,186	56,757	74,375	24.58	3,026
2001	716,454.38	323,121	299,729	416,725	24.95	16,702
2002	109,571.13	47,861	44,396	65,175	25.14	2,592
2003	118,221.43	49,653	46,058	72,163	25.55	2,824
2004	494,646.96	199,936	185,462	309,185	25.79	11,989
2005	289,259.37	112,175	104,054	185,205	26.05	7,110
2006	251,806.96	93,269	86,517	165,290	26.34	6,275
2007	893,846.74	314,992	292,189	601,658	26.65	22,576
2008	797,180.03	266,896	247,575	549,605	26.82	20,492
2009	104,329.01	32,989	30,601	73,728	27.03	2,728
2010	91,265.11	27,078	25,118	66,147	27.26	2,427
2011	1,503,528.26	415,275	385,212	1,118,316	27.52	40,636

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

PNG
SURVIVOR CURVE.. IOWA 47-S0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2012	453,390.05	115,433	107,077	346,314	27.81	12,453
2013	22,544.79	5,251	4,871	17,674	28.00	631
2014	3,111,653.81	653,447	606,142	2,505,512	28.21	88,816
2015	1,492,836.87	278,563	258,397	1,234,440	28.34	43,558
2016	1,196,608.67	193,492	179,485	1,017,124	28.51	35,676
2017	1,887,319.71	256,487	237,919	1,649,400	28.61	57,651
2018	10,889,707.56	1,181,533	1,095,999	9,793,709	28.76	340,532
2019	7,258,901.27	580,712	538,673	6,720,229	28.75	233,747
2020	4,563,622.94	225,899	209,546	4,354,077	28.80	151,183
2021	2,162,397.27	37,193	34,501	2,127,897	28.57	74,480
	45,398,724.29	9,563,101	8,870,808	36,527,916		1,332,003

CPG
SURVIVOR CURVE.. IOWA 47-S0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1911	59.72	60	60			
1912	77.00	77	77			
1923	246.71	247	247			
1927	227.78	228	228			
1928	201.25	200	201			
1929	1,840.28	1,818	1,840			
1930	56.71	56	57			
1931	20.00	19	20			
1932	25.00	24	25			
1933	105.36	101	105			
1935	274.21	258	274			
1936	279.38	261	279			
1937	449.37	416	449			
1938	1,104.93	1,014	1,105			
1939	461.30	419	461			
1940	446.16	402	446			
1941	101.96	91	102			
1942	248.41	220	246	3	5.39	1
1946	106.56	91	102	5	6.92	1
1948	493.03	412	460	33	7.70	4
1949	542.60	449	502	41	8.09	5
1950	71.03	58	65	6	8.48	1
1951	51.06	41	46	5	8.87	1
1952	43.61	35	39	4	9.27	

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

CPG
SURVIVOR CURVE.. IOWA 47-S0
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1953	325.19	258	288	37	9.66	4
1954	322.15	253	283	39	10.06	4
1955	1,096.04	852	952	144	10.46	14
1956	530.06	408	456	74	10.86	7
1957	7,634.79	5,804	6,486	1,149	11.27	102
1958	7,465.05	5,611	6,271	1,195	11.67	102
1959	2,949.29	2,191	2,449	501	12.08	41
1960	1,747.49	1,283	1,434	314	12.49	25
1961	4,346.71	3,154	3,525	822	12.90	64
1962	4,388.76	3,146	3,516	873	13.31	66
1963	3,975.82	2,814	3,145	831	13.73	61
1964	7,791.31	5,446	6,086	1,705	14.15	120
1965	7,770.53	5,362	5,992	1,778	14.57	122
1966	26,352.72	17,948	20,058	6,295	14.99	420
1967	17,123.14	11,509	12,862	4,261	15.41	277
1968	8,251.41	5,471	6,114	2,137	15.84	135
1969	12,239.86	8,003	8,944	3,296	16.27	203
1970	12,319.83	7,942	8,876	3,444	16.70	206
1971	8,708.66	5,533	6,183	2,525	17.14	147
1972	19,997.61	12,518	13,989	6,008	17.58	342
1973	17,355.92	10,702	11,960	5,396	18.02	299
1974	16,876.10	10,248	11,453	5,424	18.46	294
1975	42,435.55	25,362	28,343	14,093	18.91	745
1976	8,050.34	4,734	5,290	2,760	19.36	143
1977	25,005.27	14,466	16,166	8,839	19.81	446
1978	10,014.34	5,695	6,364	3,650	20.27	180
1979	40,405.84	22,584	25,239	15,167	20.73	732
1980	29,172.13	16,014	17,896	11,276	21.20	532
1981	38,219.82	20,606	23,028	15,192	21.66	701
1982	104,206.24	70,381	78,654	25,553	18.98	1,346
1983	86,923.49	57,891	64,695	22,228	19.31	1,151
1984	60,843.06	39,925	44,618	16,225	19.65	826
1985	50,591.33	32,682	36,523	14,068	20.00	703
1986	95,865.17	60,913	68,073	27,792	20.37	1,364
1987	85,664.81	53,489	59,776	25,889	20.75	1,248
1988	81,132.47	49,734	55,580	25,553	21.15	1,208
1989	73,193.89	44,246	49,447	23,747	21.26	1,117
1990	108,490.02	64,248	71,800	36,690	21.69	1,692
1991	76,293.48	44,449	49,674	26,620	21.85	1,218
1992	128,817.79	73,349	81,970	46,847	22.31	2,100
1993	140,158.45	78,293	87,496	52,663	22.52	2,338
1994	102,404.76	55,759	62,313	40,092	23.01	1,742

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 378 MEASURING AND REGULATING STATION EQUIPMENT - GENERAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 47-S0						
NET SALVAGE PERCENT.. 0						
1995	130,637.67	69,578	77,756	52,881	23.25	2,274
1996	234,273.11	121,869	136,193	98,080	23.52	4,170
1997	176,086.74	89,311	99,809	76,278	23.81	3,204
1998	176,072.27	86,892	97,105	78,967	24.12	3,274
1999	270,954.30	129,841	145,102	125,852	24.45	5,147
2000	174,082.00	81,227	90,774	83,308	24.58	3,389
2001	462,778.53	208,713	233,245	229,533	24.95	9,200
2002	249,442.94	108,957	121,764	127,679	25.14	5,079
2003	299,672.26	125,862	140,656	159,016	25.55	6,224
2004	340,373.65	137,579	153,750	186,624	25.79	7,236
2005	224,788.96	87,173	97,419	127,370	26.05	4,889
2006	415,268.07	153,815	171,894	243,374	26.34	9,240
2007	353,902.21	124,715	139,374	214,528	26.65	8,050
2008	465,266.40	155,771	174,080	291,186	26.82	10,857
2009	210,140.88	66,447	74,257	135,884	27.03	5,027
2010	268,431.86	79,644	89,005	179,427	27.26	6,582
2011	632,008.60	174,561	195,079	436,930	27.52	15,877
2012	438,082.67	111,536	124,646	313,437	27.81	11,271
2013	882,750.91	205,593	229,758	652,993	28.00	23,321
2014	399,981.65	83,996	93,869	306,113	28.21	10,851
2015	3,978,559.42	742,399	829,660	3,148,899	28.34	111,111
2016	991,971.84	160,402	179,256	812,716	28.51	28,506
2017	520,519.31	70,739	79,054	441,466	28.61	15,430
2018	481,070.87	52,196	58,331	422,740	28.76	14,699
2019	213,033.77	17,043	19,046	193,988	28.75	6,747
2020	1,665,179.23	82,426	92,114	1,573,065	28.80	54,620
2021	6,789,693.28	116,783	130,510	6,659,184	28.57	233,083
	23,030,013.51	4,613,341	5,155,209	17,874,805		643,958
	118,827,801.22	26,080,708	26,330,599	92,497,203		3,363,066

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.5   2.83

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1954	1,330.58	1,200	1,331			
1956	21,290.16	18,920	21,290			
1957	5,372.45	4,740	5,372			
1958	8,518.07	7,458	8,518			
1959	4,392.86	3,817	4,393			
1960	27,087.71	23,356	27,088			
1961	1,916.00	1,639	1,916			
1962	1,339.47	1,136	1,339			
1963	30.71	26	31			
1965	41,595.76	34,376	41,596			
1966	19,579.16	16,033	19,579			
1967	14,375.52	11,660	14,376			
1968	818.29	657	818			
1969	15,932.36	12,661	15,932			
1970	553.00	435	553			
1972	36,690.90	28,179	36,691			
1973	38,195.02	28,977	38,195			
1974	19,018.54	14,243	19,019			
1975	25,329.73	18,716	25,330			
1976	12,818.60	9,341	12,790	28	12.21	2
1977	148.01	106	145	3	12.69	
1978	4,242.67	3,000	4,108	135	13.18	10
1979	1,542.38	1,073	1,469	73	13.68	5
1980	4,638.03	3,176	4,349	289	14.19	20
1981	80,176.22	53,950	73,871	6,305	14.72	428
1982	141,945.62	105,409	141,946			
1983	6,800.47	4,975	6,800			
1984	199,926.07	143,947	197,254	2,672	14.58	183
1985	433,461.53	306,934	420,598	12,863	15.05	855
1986	265,735.11	184,898	253,370	12,365	15.52	797
1987	791,585.85	540,732	740,977	50,609	16.01	3,161
1988	18,764.80	12,572	17,228	1,537	16.50	93
1989	37,807.02	24,820	34,011	3,796	17.00	223
1990	128,484.87	82,564	113,139	15,346	17.52	876
1991	257,739.07	161,937	221,906	35,833	18.04	1,986
1992	198,243.74	121,642	166,689	31,555	18.58	1,698
1993	32,985.36	19,742	27,053	5,932	19.12	310
1994	6,197.62	3,613	4,951	1,247	19.67	63
1995	265,285.40	150,443	206,155	59,130	20.23	2,923
1996	390,043.61	214,836	294,394	95,649	20.80	4,599
1998	8,401.63	4,344	5,953	2,449	21.95	112
2003	278,252.13	119,426	163,652	114,600	24.60	4,659

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2008	144,233.30	47,510	65,104	79,129	27.48	2,880
2009	23,277.53	7,188	9,850	13,428	27.98	480
2013	87,005.59	19,228	26,349	60,657	29.96	2,025
2014	78,923.32	15,564	21,328	57,596	30.52	1,887
2017	32,073.62	3,996	5,476	26,598	31.60	842
2019	90,422.23	6,601	9,045	81,377	31.75	2,563
2021	3,108,012.93	51,593	70,699	3,037,314	29.62	102,543
	7,412,540.62	2,653,389	3,604,024	3,808,516		136,223
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1960	16,780.37	14,468	12,252	4,528	6.20	730
1962	29,310.05	24,868	21,059	8,251	6.82	1,210
1963	28,716.91	24,160	20,459	8,257	7.14	1,156
1964	1,610.71	1,343	1,137	473	7.47	63
1965	15,335.53	12,674	10,733	4,603	7.81	589
1966	114,389.19	93,672	79,324	35,065	8.15	4,302
1967	4,284.76	3,475	2,943	1,342	8.50	158
1968	126,189.95	101,317	85,798	40,391	8.87	4,554
1969	116,466.84	92,553	78,377	38,090	9.24	4,122
1970	18,752.91	14,740	12,482	6,271	9.63	651
1971	13,464.24	10,463	8,860	4,604	10.03	459
1972	2,349.36	1,804	1,528	822	10.44	79
1974	21,308.55	15,958	13,514	7,795	11.30	690
1975	37,036.13	27,366	23,174	13,862	11.75	1,180
1977	2,043.72	1,467	1,242	801	12.69	63
1978	2,934.41	2,075	1,757	1,177	13.18	89
1979	1,353.24	942	798	556	13.68	41
1980	47,010.45	32,187	27,257	19,753	14.19	1,392
1981	702,199.80	472,503	400,131	302,069	14.72	20,521
1982	114,036.20	84,683	71,712	42,324	13.69	3,092
1983	6,538.51	4,783	4,050	2,488	14.13	176
1984	1,848.56	1,331	1,127	721	14.58	49
1985	33,053.50	23,405	19,820	13,233	15.05	879
1986	796.80	554	469	328	15.52	21
1987	900.93	615	521	380	16.01	24
1988	228,712.92	153,238	129,767	98,946	16.50	5,997
1989	5,767.35	3,786	3,206	2,561	17.00	151

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1990	8,208.45	5,275	4,467	3,741	17.52	214
1991	15,153.04	9,521	8,063	7,090	18.04	393
1992	1,292.66	793	672	621	18.58	33
1993	49,169.36	29,428	24,921	24,249	19.12	1,268
1994	82,378.57	48,027	40,671	41,708	19.67	2,120
1995	52,734.74	29,906	25,325	27,409	20.23	1,355
1996	44,580.63	24,555	20,794	23,787	20.80	1,144
1997	532,333.33	284,319	240,770	291,563	21.37	13,644
1998	118,063.23	61,039	51,690	66,373	21.95	3,024
1999	58,548.09	29,245	24,766	33,782	22.55	1,498
2000	69,703.96	33,723	28,558	41,146	22.94	1,794
2001	173,986.69	80,973	68,571	105,416	23.55	4,476
2002	184,888.86	82,571	69,924	114,965	24.17	4,757
2003	175,733.00	75,425	63,872	111,861	24.60	4,547
2004	75,956.41	31,104	26,340	49,617	25.24	1,966
2005	48,587.58	18,920	16,022	32,566	25.87	1,259
2006	162,733.73	60,277	51,045	111,689	26.34	4,240
2007	9,461.70	3,306	2,800	6,662	27.00	247
2008	460,995.77	151,852	128,593	332,403	27.48	12,096
2009	53,996.90	16,674	14,120	39,877	27.98	1,425
2010	265,809.52	76,420	64,715	201,095	28.50	7,056
2011	1,348,202.00	358,082	303,235	1,044,967	29.03	35,996
2012	500,205.13	121,650	103,017	397,188	29.56	13,437
2013	309,369.28	68,371	57,899	251,471	29.96	8,394
2014	8,711,938.63	1,717,994	1,454,853	7,257,086	30.52	237,781
2015	784,772.22	136,236	115,369	669,403	30.95	21,629
2018	1.37			1	31.84	
2020	1,817,684.99	82,886	70,191	1,747,494	31.39	55,670
2021	185,706.35	3,083	2,611	183,096	29.62	6,181
	17,995,388.08	4,862,085	4,117,370	13,878,018		500,082
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1955	266.15	238	208	59	4.72	12
1957	1,419.60	1,252	1,092	328	5.30	62
1959	1,154.96	1,004	876	279	5.90	47
1960	352.50	304	265	87	6.20	14
1961	3,229.10	2,762	2,409	820	6.51	126

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 379 MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1966	2,958.56	2,423	2,113	846	8.15	104
1967	3,788.99	3,073	2,680	1,109	8.50	130
1968	2,785.64	2,237	1,951	835	8.87	94
1970	2,147.66	1,688	1,472	676	9.63	70
1972	481.68	370	323	159	10.44	15
1973	1,415.71	1,074	937	479	10.86	44
1974	1,983.52	1,485	1,295	688	11.30	61
1975	1,411.62	1,043	910	502	11.75	43
1977	3,626.30	2,604	2,271	1,355	12.69	107
1979	10,681.17	7,434	6,483	4,198	13.68	307
1981	703.40	473	412	291	14.72	20
1982	2,492.78	1,851	1,614	879	13.69	64
1988	1,548.80	1,038	905	644	16.50	39
1989	1,790.48	1,175	1,025	766	17.00	45
1992	417.27	256	223	194	18.58	10
1995	551.52	313	273	279	20.23	14
2012	1,055.35	257	224	831	29.56	28
2013	422.81	93	81	342	29.96	11
2019	181,294.79	13,235	11,542	169,753	31.75	5,347
	227,980.36	47,682	41,582	186,398		6,814
	25,635,909.06	7,563,156	7,762,977	17,872,932		643,119

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.8 2.51

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1884	0.36		0			
1886	0.47		0			
1887	21.14	21	21			
1888	17.65	18	18			
1890	0.66	1	1			
1891	4.22	4	4			
1894	6.48	6	6			
1895	137.12	137	137			
1896	80.35	80	80			
1897	49.32	49	49			
1898	121.41	121	121			
1899	222.76	223	223			
1901	33.34	33	33			
1902	73.40	73	73			
1903	155.68	156	156			
1904	56.94	57	57			
1905	61.20	61	61			
1906	321.75	322	322			
1907	258.82	259	259			
1908	506.87	507	507			
1909	411.47	411	411			
1910	501.74	502	502			
1911	567.80	568	568			
1912	582.23	582	582			
1913	392.76	393	393			
1914	735.73	736	736			
1915	1,021.80	1,022	1,022			
1916	1,056.66	1,057	1,057			
1917	1,204.02	1,204	1,204			
1918	1,365.32	1,365	1,365			
1919	1,010.25	1,010	1,010			
1920	798.43	798	798			
1921	2,044.62	2,045	2,045			
1922	2,754.66	2,755	2,755			
1923	3,508.86	3,509	3,509			
1924	2,927.58	2,928	2,928			
1925	3,655.22	3,655	3,655			
1926	3,562.89	3,563	3,563			
1927	6,042.85	6,043	6,043			
1928	4,255.55	4,256	4,256			
1929	7,246.53	7,247	7,247			
1930	6,300.81	6,276	6,045	256	0.18	256

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1931	3,807.99	3,774	3,635	173	0.41	173
1932	1,092.85	1,077	1,037	56	0.66	56
1933	2,595.89	2,543	2,449	147	0.93	147
1934	1,986.62	1,935	1,864	123	1.20	102
1935	2,234.70	2,163	2,083	151	1.47	103
1936	3,561.73	3,427	3,301	261	1.74	150
1937	3,344.57	3,198	3,080	264	2.01	131
1938	3,076.75	2,924	2,816	261	2.28	114
1939	2,853.33	2,695	2,596	258	2.56	101
1940	3,160.17	2,965	2,856	304	2.84	107
1941	5,442.64	5,073	4,886	557	3.12	179
1942	2,098.42	1,943	1,871	227	3.41	67
1943	1,309.76	1,205	1,161	149	3.69	40
1944	2,142.87	1,957	1,885	258	3.98	65
1945	1,494.64	1,356	1,306	189	4.27	44
1946	3,440.33	3,099	2,985	456	4.56	100
1947	11,898.01	10,641	10,249	1,649	4.86	339
1948	12,528.61	11,123	10,713	1,816	5.16	352
1949	17,826.72	15,711	15,132	2,695	5.46	494
1950	19,983.24	17,481	16,837	3,147	5.76	546
1951	15,164.99	13,164	12,679	2,486	6.07	410
1952	18,148.43	15,631	15,055	3,094	6.38	485
1953	14,931.30	12,760	12,290	2,642	6.69	395
1954	25,237.95	21,392	20,603	4,635	7.01	661
1955	44,256.68	37,214	35,842	8,415	7.32	1,150
1956	78,316.56	65,293	62,886	15,431	7.65	2,017
1957	99,971.35	82,650	79,603	20,368	7.97	2,556
1958	135,417.63	110,984	106,893	28,525	8.30	3,437
1959	232,486.52	188,870	181,907	50,579	8.63	5,861
1960	315,687.93	254,129	244,761	70,927	8.97	7,907
1961	338,782.88	270,217	260,256	78,527	9.31	8,435
1962	323,436.79	255,586	246,164	77,273	9.65	8,008
1963	372,248.04	291,325	280,585	91,663	10.00	9,166
1964	365,335.37	283,135	272,697	92,638	10.35	8,951
1965	487,668.53	374,125	360,333	127,336	10.71	11,889
1966	595,465.84	452,167	435,498	159,968	11.07	14,451
1967	562,986.01	422,971	407,378	155,608	11.44	13,602
1968	642,967.26	477,892	460,275	182,693	11.81	15,469
1969	668,660.07	491,465	473,347	195,313	12.19	16,022
1970	680,416.10	494,486	476,257	204,159	12.57	16,242
1971	750,010.70	538,703	518,844	231,167	12.96	17,837
1972	1,015,835.73	721,020	694,440	321,396	13.35	24,075

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1973	1,306,717.32	916,126	882,353	424,364	13.75	30,863
1974	1,352,833.51	936,688	902,157	450,676	14.15	31,850
1975	936,663.43	640,191	616,591	320,073	14.56	21,983
1976	1,052,844.22	709,985	683,812	369,033	14.98	24,635
1977	1,997,970.30	1,329,090	1,280,094	717,877	15.40	46,615
1978	1,807,630.51	1,185,571	1,141,865	665,765	15.83	42,057
1979	3,256,989.21	2,104,992	2,027,392	1,229,597	16.27	75,574
1980	5,312,900.37	3,382,936	3,258,225	2,054,675	16.71	122,961
1981	5,410,728.05	3,391,120	3,266,108	2,144,620	17.17	124,905
1982	4,827,029.87	3,470,152	3,342,226	1,484,804	15.45	96,104
1983	3,511,355.78	2,487,444	2,395,745	1,115,611	15.85	70,386
1984	3,678,991.26	2,579,709	2,484,609	1,194,382	15.98	74,742
1985	4,181,889.95	2,884,668	2,778,326	1,403,564	16.41	85,531
1986	4,430,008.16	3,003,546	2,892,821	1,537,187	16.86	91,174
1987	5,190,730.53	3,455,988	3,328,584	1,862,146	17.32	107,514
1988	6,586,446.79	4,324,661	4,165,234	2,421,213	17.52	138,197
1989	9,293,688.66	5,980,489	5,760,020	3,533,668	18.01	196,206
1990	10,301,104.05	6,522,659	6,282,203	4,018,901	18.25	220,214
1991	9,281,713.94	5,747,237	5,535,367	3,746,347	18.76	199,699
1992	9,340,011.41	5,675,925	5,466,684	3,873,327	19.04	203,431
1993	6,050,821.45	3,586,927	3,454,696	2,596,125	19.58	132,591
1994	12,260,256.60	7,113,401	6,851,168	5,409,089	19.90	271,814
1995	13,094,905.26	7,390,765	7,118,307	5,976,598	20.45	292,254
1996	10,998,178.77	6,057,797	5,834,478	5,163,700	20.80	248,255
1997	11,969,812.99	6,423,002	6,186,220	5,783,593	21.16	273,327
1998	9,640,758.89	5,029,584	4,844,170	4,796,589	21.55	222,580
1999	9,741,389.87	4,909,660	4,728,667	5,012,723	22.14	226,410
2000	10,161,041.53	4,958,588	4,775,791	5,385,250	22.56	238,708
2001	10,099,605.80	4,761,964	4,586,416	5,513,190	22.98	239,913
2002	10,568,987.06	4,802,548	4,625,504	5,943,483	23.42	253,778
2003	9,021,785.28	3,938,911	3,793,704	5,228,081	23.87	219,023
2004	11,376,037.49	4,757,459	4,582,077	6,793,961	24.34	279,127
2005	9,778,557.83	3,887,955	3,744,627	6,033,931	25.00	241,357
2006	10,447,062.80	3,951,079	3,805,424	6,641,639	25.48	260,661
2007	10,336,796.40	3,702,640	3,566,143	6,770,653	25.98	260,610
2008	13,563,768.20	4,577,772	4,409,014	9,154,754	26.50	345,462
2009	13,897,926.05	4,394,524	4,232,521	9,665,405	27.03	357,581
2010	14,219,540.20	4,186,233	4,031,909	10,187,631	27.56	369,653
2011	21,779,754.77	5,900,136	5,682,630	16,097,125	28.26	569,608
2012	31,866,536.89	7,902,901	7,611,563	24,254,974	28.81	841,894
2013	41,405,043.59	9,258,168	8,916,869	32,488,175	29.52	1,100,548
2014	40,259,369.71	8,031,744	7,735,657	32,523,713	30.09	1,080,881

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2015	41,912,899.27	7,301,227	7,032,070	34,880,829	30.81	1,132,127
2016	45,641,971.62	6,777,833	6,527,971	39,114,001	31.54	1,240,140
2017	43,226,369.78	5,290,908	5,095,861	38,130,509	32.26	1,181,975
2018	49,299,605.03	4,727,832	4,553,542	44,746,063	33.00	1,355,941
2019	66,718,890.51	4,590,260	4,421,042	62,297,849	33.86	1,839,866
2020	75,802,704.60	3,138,232	3,022,542	72,780,162	34.73	2,095,599
2021	85,987,353.88	1,186,625	1,142,880	84,844,473	35.60	2,383,272
	842,129,369.66	219,291,374	211,209,037	630,920,333		21,752,288
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1912	316.08	316	316			
1917	4,229.74	4,230	4,230			
1918	859.13	859	859			
1919	3,477.63	3,478	3,478			
1920	4,176.43	4,176	4,176			
1921	3,807.14	3,807	3,807			
1922	10,344.27	10,344	10,344			
1923	12,267.77	12,268	12,268			
1924	21,221.60	21,222	21,222			
1925	25,106.58	25,107	25,107			
1926	18,646.91	18,647	18,647			
1927	16,091.01	16,091	16,091			
1928	14,479.95	14,480	14,480			
1929	13,613.01	13,613	13,613			
1930	13,568.21	13,515	13,568			
1931	13,326.51	13,208	13,327			
1932	10,830.93	10,676	10,831			
1933	6,726.58	6,591	6,727			
1934	8,773.01	8,544	8,773			
1935	6,694.55	6,481	6,695			
1936	9,338.60	8,985	9,339			
1937	10,025.01	9,587	10,025			
1938	7,784.82	7,399	7,785			
1939	12,403.70	11,713	12,404			
1940	11,117.77	10,431	11,118			
1941	10,030.38	9,350	9,988	42	3.12	13
1942	6,049.91	5,601	5,983	67	3.41	20

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

PNG
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1943	4,274.07	3,931	4,199	75	3.69	20
1944	6,869.42	6,275	6,703	166	3.98	42
1945	11,193.49	10,154	10,847	346	4.27	81
1946	18,818.93	16,953	18,110	709	4.56	155
1947	20,023.31	17,908	19,130	893	4.86	184
1948	24,183.32	21,471	22,937	1,247	5.16	242
1949	21,570.50	19,010	20,308	1,263	5.46	231
1950	30,589.50	26,759	28,586	2,004	5.76	348
1951	23,066.28	20,022	21,389	1,678	6.07	276
1952	466,543.21	401,834	429,264	37,279	6.38	5,843
1953	18,005.15	15,387	16,437	1,568	6.69	234
1954	25,628.36	21,723	23,206	2,423	7.01	346
1955	43,243.01	36,362	38,844	4,399	7.32	601
1956	50,003.99	41,688	44,534	5,470	7.65	715
1957	69,280.26	57,277	61,187	8,093	7.97	1,015
1958	101,499.81	83,186	88,864	12,635	8.30	1,522
1959	161,223.88	130,977	139,918	21,306	8.63	2,469
1960	141,092.35	113,579	121,332	19,760	8.97	2,203
1961	170,434.15	135,940	145,219	25,215	9.31	2,708
1962	307,976.17	243,369	259,982	47,994	9.65	4,973
1963	387,223.13	303,045	323,731	63,492	10.00	6,349
1964	525,652.74	407,381	435,189	90,463	10.35	8,740
1965	628,059.19	481,828	514,718	113,341	10.71	10,583
1966	696,373.17	528,791	564,887	131,486	11.07	11,878
1967	817,103.92	613,890	655,795	161,309	11.44	14,100
1968	1,047,924.06	778,880	832,048	215,877	11.81	18,279
1969	1,108,317.58	814,613	870,220	238,098	12.19	19,532
1970	1,278,476.47	929,120	992,543	285,933	12.57	22,747
1971	450,366.00	323,480	345,561	104,805	12.96	8,087
1972	1,023,487.31	726,451	776,040	247,448	13.35	18,535
1973	1,315,496.35	922,281	985,237	330,259	13.75	24,019
1974	1,351,727.79	935,923	999,811	351,917	14.15	24,870
1975	1,152,133.31	787,460	841,213	310,920	14.56	21,354
1976	1,393,091.79	939,431	1,003,558	389,534	14.98	26,004
1977	1,772,524.26	1,179,119	1,259,607	512,917	15.40	33,306
1978	1,347,230.42	883,608	943,924	403,306	15.83	25,477
1979	1,887,986.24	1,220,206	1,303,499	584,487	16.27	35,924
1980	2,491,832.31	1,586,649	1,694,956	796,876	16.71	47,689
1981	2,180,791.95	1,366,790	1,460,089	720,703	17.17	41,975
1982	1,803,307.44	1,296,398	1,384,892	418,415	15.45	27,082
1983	1,300,674.63	921,398	984,294	316,381	15.85	19,961
1984	1,828,716.85	1,282,296	1,369,827	458,889	15.98	28,716

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1985	2,155,348.08	1,486,759	1,588,247	567,101	16.41	34,558
1986	2,731,191.15	1,851,748	1,978,151	753,040	16.86	44,664
1987	3,692,295.47	2,458,330	2,626,139	1,066,156	17.32	61,556
1988	4,890,734.96	3,211,257	3,430,462	1,460,273	17.52	83,349
1989	4,612,405.42	2,968,083	3,170,689	1,441,717	18.01	80,051
1990	5,060,705.67	3,204,439	3,423,179	1,637,527	18.25	89,728
1991	3,685,591.59	2,282,118	2,437,899	1,247,693	18.76	66,508
1992	4,465,275.14	2,713,548	2,898,779	1,566,496	19.04	82,274
1993	4,744,816.35	2,812,727	3,004,728	1,740,088	19.58	88,871
1994	4,802,735.27	2,786,547	2,976,761	1,825,974	19.90	91,757
1995	5,428,454.16	3,063,820	3,272,961	2,155,493	20.45	105,403
1996	5,511,693.74	3,035,841	3,243,072	2,268,622	20.80	109,068
1997	6,383,335.42	3,425,298	3,659,114	2,724,221	21.16	128,744
1998	5,939,281.32	3,098,523	3,310,033	2,629,248	21.55	122,007
1999	4,281,374.75	2,157,813	2,305,109	1,976,266	22.14	89,262
2000	3,561,558.94	1,738,041	1,856,682	1,704,877	22.56	75,571
2001	6,218,211.49	2,931,887	3,132,022	3,086,189	22.98	134,299
2002	5,108,995.60	2,321,528	2,479,999	2,628,997	23.42	112,254
2003	5,786,971.13	2,526,592	2,699,061	3,087,910	23.87	129,364
2004	11,859,568.42	4,959,672	5,298,227	6,561,342	24.34	269,570
2005	7,685,342.19	3,055,692	3,264,278	4,421,064	25.00	176,843
2006	4,660,988.30	1,762,786	1,883,116	2,777,872	25.48	109,022
2007	6,221,020.30	2,228,369	2,380,481	3,840,539	25.98	147,827
2008	6,681,451.49	2,254,990	2,408,919	4,272,532	26.50	161,228
2009	6,848,011.99	2,165,341	2,313,150	4,534,862	27.03	167,771
2010	4,458,258.14	1,312,511	1,402,105	3,056,153	27.56	110,891
2011	7,662,245.24	2,075,702	2,217,393	5,444,853	28.26	192,670
2012	9,641,245.00	2,391,029	2,554,244	7,087,001	28.81	245,991
2013	9,525,224.27	2,129,840	2,275,226	7,249,998	29.52	245,596
2014	10,282,129.66	2,051,285	2,191,309	8,090,821	30.09	268,887
2015	14,840,744.61	2,585,258	2,761,732	12,079,013	30.81	392,048
2016	15,782,766.21	2,343,741	2,503,728	13,279,038	31.54	421,022
2017	17,425,105.42	2,132,833	2,278,423	15,146,682	32.26	469,519
2018	19,777,435.47	1,896,656	2,026,125	17,751,311	33.00	537,919
2019	26,632,143.66	1,832,291	1,957,366	24,674,778	33.86	728,729
2020	25,422,233.65	1,052,480	1,124,324	24,297,910	34.73	699,623
2021	29,523,415.14	407,423	435,234	29,088,181	35.60	817,084
	353,769,628.11	109,636,360	117,106,303	236,663,325		8,410,976

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1930	393.08	392	393			
1931	412.70	409	413			
1935	40.56	39	41			
1941	55.25	52	55			
1942	35.71	33	36			
1946	324.94	293	319	6	4.56	1
1947	129.32	116	126	3	4.86	1
1948	4.26	4	4			
1949	225.53	199	216	9	5.46	2
1951	66.68	58	63	4	6.07	1
1952	45.62	39	42	3	6.38	
1953	75.13	64	70	6	6.69	1
1954	455.66	386	420	36	7.01	5
1955	1,300.00	1,093	1,188	112	7.32	15
1956	926.71	773	840	86	7.65	11
1958	3,176.75	2,604	2,831	346	8.30	42
1959	1,183.16	961	1,045	138	8.63	16
1960	208.57	168	183	26	8.97	3
1961	21,168.19	16,884	18,356	2,812	9.31	302
1962	9,217.17	7,284	7,919	1,298	9.65	135
1963	17,208.34	13,467	14,641	2,567	10.00	257
1964	18,776.69	14,552	15,821	2,956	10.35	286
1965	16,410.87	12,590	13,688	2,723	10.71	254
1966	15,753.72	11,963	13,006	2,748	11.07	248
1967	28,522.34	21,429	23,298	5,225	11.44	457
1968	32,525.08	24,175	26,283	6,242	11.81	529
1969	28,452.87	20,913	22,737	5,716	12.19	469
1970	31,350.23	22,783	24,770	6,580	12.57	523
1971	58,937.27	42,332	46,024	12,914	12.96	996
1972	76,761.72	54,484	59,235	17,527	13.35	1,313
1973	46,522.96	32,617	35,461	11,062	13.75	805
1974	118,289.35	81,902	89,044	29,245	14.15	2,067
1975	157,985.87	107,980	117,396	40,590	14.56	2,788
1976	104,509.84	70,476	76,622	27,888	14.98	1,862
1977	54,340.52	36,148	39,300	15,040	15.40	977
1978	69,209.51	45,392	49,350	19,859	15.83	1,255
1979	61,528.13	39,766	43,234	18,294	16.27	1,124
1980	148,730.62	94,703	102,961	45,769	16.71	2,739
1981	359,036.68	225,023	244,646	114,391	17.17	6,662
1982	348,569.30	250,586	272,438	76,131	15.45	4,928
1983	308,911.20	218,833	237,916	70,995	15.85	4,479
1984	410,021.26	287,507	312,579	97,443	15.98	6,098

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1985	526,572.86	363,230	394,905	131,668	16.41	8,024
1986	604,563.76	409,894	445,638	158,925	16.86	9,426
1987	768,345.61	511,565	556,175	212,170	17.32	12,250
1988	742,973.45	487,836	530,377	212,596	17.52	12,134
1989	1,292,904.65	831,984	904,536	388,368	18.01	21,564
1990	1,316,747.98	833,765	906,472	410,275	18.25	22,481
1991	1,152,211.41	713,449	775,664	376,547	18.76	20,072
1992	1,785,857.52	1,085,266	1,179,905	605,952	19.04	31,825
1993	1,287,049.21	762,963	829,496	457,553	19.58	23,368
1994	2,285,117.75	1,325,825	1,441,442	843,676	19.90	42,396
1995	2,566,163.88	1,448,343	1,574,644	991,520	20.45	48,485
1996	2,473,571.61	1,362,443	1,481,253	992,318	20.80	47,708
1997	2,560,027.51	1,373,711	1,493,504	1,066,524	21.16	50,403
1998	2,859,879.03	1,491,999	1,622,107	1,237,772	21.55	57,437
1999	2,575,306.66	1,297,955	1,411,142	1,164,165	22.14	52,582
2000	2,298,956.35	1,121,891	1,219,724	1,079,232	22.56	47,838
2001	2,330,465.26	1,098,814	1,194,635	1,135,830	22.98	49,427
2002	3,547,388.64	1,611,933	1,752,500	1,794,889	23.42	76,639
2003	1,713,050.84	747,918	813,139	899,912	23.87	37,701
2004	2,607,743.69	1,090,558	1,185,659	1,422,085	24.34	58,426
2005	2,736,271.98	1,087,942	1,182,815	1,553,457	25.00	62,138
2006	1,871,304.64	707,727	769,444	1,101,861	25.48	43,244
2007	1,415,696.56	507,103	551,324	864,372	25.98	33,271
2008	4,087,767.53	1,379,622	1,499,930	2,587,837	26.50	97,654
2009	2,044,844.37	646,580	702,964	1,341,880	27.03	49,644
2010	3,106,805.35	914,643	994,403	2,112,402	27.56	76,647
2011	3,379,721.29	915,566	995,407	2,384,314	28.26	84,371
2012	6,027,499.34	1,494,820	1,625,174	4,402,325	28.81	152,805
2013	5,463,271.16	1,221,587	1,328,114	4,135,157	29.52	140,080
2014	7,088,817.28	1,414,219	1,537,544	5,551,273	30.09	184,489
2015	6,875,922.04	1,197,786	1,302,238	5,573,685	30.81	180,905
2016	6,585,210.75	977,904	1,063,181	5,522,030	31.54	175,080
2017	5,291,786.88	647,715	704,198	4,587,589	32.26	142,207
2018	5,568,497.35	534,019	580,587	4,987,910	33.00	151,149

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 380 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2019	6,781,375.79	466,559	507,245	6,274,131	33.86	185,296
2020	9,911,686.49	410,344	446,128	9,465,559	34.73	272,547
2021	7,318,450.14	100,995	109,802	7,208,648	35.60	202,490
	125,401,625.97	36,357,945	39,528,428	85,873,198		3,005,854
	1,321,300,623.74	365,285,679	367,843,768	953,456,856		33,169,118

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.7 2.51

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1929	54.93	55	55			
1930	105.12	105	105			
1931	135.58	136	136			
1932	144.99	145	145			
1933	39.72	40	40			
1934	286.90	287	287			
1935	618.93	619	619			
1936	1,035.81	1,036	1,036			
1937	1,823.58	1,824	1,824			
1938	1,847.19	1,847	1,847			
1939	2,416.02	2,416	2,416			
1940	2,769.15	2,769	2,769			
1941	4,017.29	4,017	4,017			
1942	1,538.43	1,538	1,538			
1943	453.32	453	453			
1944	1,256.80	1,257	1,257			
1945	1,401.16	1,401	1,401			
1946	2,694.68	2,695	2,695			
1947	3,525.59	3,526	3,526			
1948	2,340.03	2,340	2,340			
1949	4,941.22	4,941	4,941			
1950	4,459.18	4,459	4,459			
1951	5,291.61	5,292	5,292			
1952	7,433.11	7,433	7,433			
1953	5,771.03	5,771	5,771			
1954	2,116.06	2,116	2,116			
1955	3,790.73	3,791	3,791			
1956	4,101.54	4,102	4,102			
1957	3,380.95	3,366	3,262	119	0.15	119
1958	4,845.09	4,792	4,644	201	0.38	201
1959	9,413.84	9,242	8,957	457	0.64	457
1960	5,755.01	5,607	5,434	321	0.90	321
1961	7,346.68	7,101	6,882	465	1.17	397
1962	8,833.32	8,467	8,206	628	1.45	433
1963	9,096.41	8,649	8,382	714	1.72	415
1964	10,851.53	10,231	9,915	936	2.00	468
1965	11,170.56	10,440	10,118	1,053	2.29	460
1966	28,508.80	26,415	25,600	2,909	2.57	1,132
1967	58,623.69	53,834	52,173	6,450	2.86	2,255
1968	95,000.52	86,450	83,783	11,218	3.15	3,561
1969	91,488.72	82,496	79,951	11,538	3.44	3,354
1970	79,374.97	70,893	68,706	10,669	3.74	2,853

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1971	51,186.85	45,293	43,896	7,291	4.03	1,809
1972	51,877.77	45,474	44,071	7,807	4.32	1,807
1973	83,817.00	72,753	70,509	13,308	4.62	2,881
1974	88,022.18	75,623	73,290	14,732	4.93	2,988
1975	66,917.47	56,899	55,144	11,774	5.24	2,247
1976	38,135.20	32,077	31,087	7,048	5.56	1,268
1977	46,075.69	38,335	37,152	8,923	5.88	1,518
1978	123,704.78	101,721	98,583	25,122	6.22	4,039
1979	138,683.59	112,651	109,176	29,508	6.57	4,491
1980	653,711.35	524,087	507,919	145,793	6.94	21,008
1981	370,699.09	293,171	284,127	86,572	7.32	11,827
1982	231,781.74	195,925	189,881	41,901	7.23	5,795
1983	28,172.54	23,535	22,809	5,364	7.59	707
1984	107,542.53	89,131	86,381	21,161	7.75	2,730
1985	349,577.07	285,814	276,997	72,580	8.14	8,916
1986	249,754.17	201,252	195,043	54,711	8.56	6,391
1987	405,891.24	322,075	312,139	93,752	8.98	10,440
1988	347,910.26	271,579	263,201	84,710	9.42	8,993
1989	544,088.92	417,316	404,442	139,647	9.87	14,149
1990	913,619.37	687,773	666,555	247,064	10.34	23,894
1991	900,979.95	665,013	644,497	256,483	10.82	23,705
1992	832,932.43	604,459	585,811	247,121	11.15	22,163
1993	671,263.64	476,329	461,634	209,629	11.66	17,978
1994	967,724.11	670,633	649,944	317,780	12.18	26,090
1995	983,432.46	664,604	644,101	339,332	12.71	26,698
1996	684,129.19	451,799	437,861	246,268	13.11	18,785
1997	962,566.64	617,872	598,811	363,756	13.67	26,610
1998	807,128.39	502,680	487,172	319,956	14.23	22,485
1999	996,114.65	602,849	584,251	411,864	14.68	28,056
2000	891,686.81	521,458	505,371	386,316	15.26	25,316
2001	1,205,548.58	679,688	658,720	546,829	15.86	34,478
2002	856,061.48	465,697	451,330	404,731	16.34	24,769
2003	938,953.21	489,852	474,740	464,213	16.96	27,371
2004	871,259.97	436,066	422,613	448,647	17.47	25,681
2005	1,022,572.69	489,301	474,206	548,367	17.98	30,499
2006	1,183,803.76	537,684	521,096	662,707	18.63	35,572
2007	743,021.64	319,945	310,075	432,947	19.17	22,585
2008	2,976,363.78	1,209,594	1,172,278	1,804,086	19.72	91,485
2009	1,487,298.57	566,958	549,467	937,831	20.29	46,221
2010	1,694,396.45	604,052	585,417	1,108,980	20.76	53,419
2011	3,000,142.78	989,147	958,632	2,041,511	21.35	95,621
2012	2,559,747.09	775,603	751,676	1,808,072	21.85	82,749

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
2013	3,161,325.68	868,100	841,319	2,320,007	22.46	103,295
2014	3,238,639.57	799,296	774,638	2,464,002	22.89	107,645
2015	2,715,717.26	589,582	571,393	2,144,324	23.44	91,481
2016	3,363,103.78	630,918	611,454	2,751,650	23.82	115,518
2017	4,181,617.91	654,841	634,639	3,546,979	24.24	146,328
2018	7,795,907.63	971,370	941,403	6,854,505	24.59	278,752
2019	4,121,227.33	378,329	366,657	3,754,570	24.75	151,700
2020	4,635,432.17	266,074	257,866	4,377,567	24.61	177,878
2021	6,783,408.61	142,452	138,057	6,645,351	23.31	285,086
	72,614,776.81	22,989,123	22,281,953	50,332,824		2,420,343
PNG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1932	35.33	35	35			
1945	263.01	263	263			
1951	108.54	109	109			
1952	12,605.13	12,605	12,605			
1953	208.14	208	208			
1954	440.59	441	441			
1955	2,293.15	2,293	2,293			
1956	4,572.33	4,572	4,572			
1957	1,870.52	1,862	1,871			
1958	8,168.45	8,080	8,168			
1959	6,807.32	6,683	6,807			
1960	12,620.06	12,296	12,620			
1961	33,147.20	32,039	33,147			
1962	60,981.72	58,455	60,982			
1963	73,963.16	70,329	73,963			
1964	139,374.55	131,411	138,555	819	2.00	410
1965	256,696.43	239,901	252,944	3,753	2.29	1,639
1966	375,484.19	347,912	366,827	8,657	2.57	3,368
1967	293,446.38	269,469	284,119	9,327	2.86	3,261
1968	343,395.50	312,490	329,479	13,916	3.15	4,418
1969	511,486.19	461,212	486,287	25,199	3.44	7,325
1970	445,393.69	397,799	419,426	25,967	3.74	6,943
1971	280,998.88	248,645	262,163	18,836	4.03	4,674
1972	283,767.26	248,742	262,265	21,502	4.32	4,977
1973	122,880.73	106,660	112,459	10,422	4.62	2,256

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1974	38,164.08	32,788	34,571	3,593	4.93	729
1975	64,421.51	54,777	57,755	6,666	5.24	1,272
1976	27,703.03	23,302	24,569	3,134	5.56	564
1977	45,583.69	37,926	39,988	5,596	5.88	952
1978	39,536.78	32,511	34,279	5,258	6.22	845
1979	126,355.22	102,637	108,217	18,138	6.57	2,761
1980	944,202.48	756,977	798,132	146,071	6.94	21,048
1981	1,398,457.95	1,105,984	1,166,114	232,344	7.32	31,741
1982	107,345.80	90,739	95,672	11,674	7.23	1,615
1983	64,853.91	54,179	57,125	7,729	7.59	1,018
1984	278,649.64	230,945	243,501	35,149	7.75	4,535
1985	529,827.93	433,187	456,738	73,090	8.14	8,979
1986	614,916.98	495,500	522,439	92,478	8.56	10,804
1987	618,212.65	490,552	517,222	100,991	8.98	11,246
1988	679,086.35	530,095	558,915	120,171	9.42	12,757
1989	663,686.78	509,048	536,724	126,963	9.87	12,864
1990	708,225.41	533,152	562,138	146,087	10.34	14,128
1991	894,972.61	660,579	696,493	198,480	10.82	18,344
1992	1,261,046.34	915,141	964,895	296,151	11.15	26,561
1993	1,400,778.49	993,992	1,048,033	352,746	11.66	30,253
1994	2,348,503.61	1,627,513	1,715,997	632,507	12.18	51,930
1995	496,985.24	335,863	354,123	142,862	12.71	11,240
1996	1,238,955.63	818,206	862,690	376,266	13.11	28,701
1997	1,216,436.55	780,831	823,283	393,154	13.67	28,760
1998	1,544,411.43	961,859	1,014,153	530,259	14.23	37,263
1999	776,713.67	470,067	495,623	281,090	14.68	19,148
2000	845,686.24	494,557	521,445	324,241	15.26	21,248
2001	1,047,955.56	590,837	622,959	424,996	15.86	26,797
2002	1,047,841.26	570,026	601,017	446,824	16.34	27,345
2003	608,921.51	317,674	334,945	273,976	16.96	16,154
2004	1,855,356.02	928,606	979,092	876,264	17.47	50,158
2005	1,255,501.59	600,758	633,420	622,082	17.98	34,599
2006	1,317,438.67	598,381	630,913	686,525	18.63	36,851
2007	1,848,585.54	796,001	839,278	1,009,308	19.17	52,650
2008	1,436,865.71	583,942	615,689	821,176	19.72	41,642
2009	1,481,482.02	564,741	595,445	886,037	20.29	43,669
2010	999,646.09	356,374	375,749	623,897	20.76	30,053
2011	1,929,549.59	636,172	670,759	1,258,791	21.35	58,960
2012	1,414,796.52	428,683	451,989	962,807	21.85	44,064
2013	1,345,218.26	369,397	389,480	955,738	22.46	42,553
2014	1,621,110.12	400,090	421,842	1,199,268	22.89	52,393
2015	1,660,714.04	360,541	380,143	1,280,571	23.44	54,632

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
2016	1,327,189.19	248,981	262,517	1,064,672	23.82	44,697
2017	2,725,215.13	426,769	449,971	2,275,244	24.24	93,863
2018	4,304,570.20	536,349	565,509	3,739,061	24.59	152,056
2019	2,118,147.21	194,446	205,018	1,913,130	24.75	77,298
2020	3,932,081.79	225,701	237,972	3,694,110	24.61	150,106
2021	2,964,564.15	62,256	65,641	2,898,923	23.31	124,364
	60,487,478.62	26,344,143	27,772,791	32,714,687		1,705,481
CPG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1967	16,556.84	15,204	11,543	5,014	2.86	1,753
1968	22,991.20	20,922	15,884	7,107	3.15	2,256
1969	41,343.79	37,280	28,304	13,040	3.44	3,791
1970	28,940.51	25,848	19,624	9,316	3.74	2,491
1971	26,642.55	23,575	17,899	8,744	4.03	2,170
1972	65,539.55	57,450	43,617	21,922	4.32	5,075
1973	90,590.20	78,632	59,699	30,891	4.62	6,686
1974	49,618.21	42,629	32,365	17,253	4.93	3,500
1975	53,086.67	45,139	34,270	18,816	5.24	3,591
1976	36,099.69	30,365	23,054	13,046	5.56	2,346
1977	19,605.74	16,312	12,384	7,221	5.88	1,228
1978	9,616.75	7,908	6,004	3,613	6.22	581
1979	21,038.77	17,090	12,975	8,064	6.57	1,227
1980	82,470.72	66,118	50,198	32,273	6.94	4,650
1981	35,611.75	28,164	21,383	14,229	7.32	1,944
1982	74,822.56	63,248	48,019	26,803	7.23	3,707
1983	67,256.00	56,186	42,658	24,598	7.59	3,241
1984	50,856.68	42,150	32,001	18,856	7.75	2,433
1985	66,659.91	54,501	41,378	25,282	8.14	3,106
1986	88,458.81	71,280	54,117	34,342	8.56	4,012
1987	68,779.44	54,576	41,435	27,344	8.98	3,045
1988	10,880.03	8,493	6,448	4,432	9.42	470
1989	28,639.10	21,966	16,677	11,962	9.87	1,212
1990	158,572.07	119,373	90,630	67,942	10.34	6,571
1991	176,704.24	130,425	99,021	77,683	10.82	7,180
1992	156,321.04	113,442	86,127	70,194	11.15	6,295
1993	86,026.11	61,044	46,346	39,680	11.66	3,403
1994	60,048.42	41,614	31,594	28,454	12.18	2,336

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2						
NET SALVAGE PERCENT.. 0						
1996	23,863.63	15,760	11,965	11,898	13.11	908
1997	16,217.76	10,410	7,903	8,314	13.67	608
2001	4,157.02	2,344	1,780	2,377	15.86	150
2002	3,650.45	1,986	1,508	2,143	16.34	131
2003	14,474.51	7,551	5,733	8,742	16.96	515
2004	101,296.17	50,699	38,492	62,805	17.47	3,595
2005	44,912.16	21,490	16,316	28,597	17.98	1,590
2006	84,560.74	38,407	29,159	55,401	18.63	2,974
2007	44,364.00	19,103	14,503	29,861	19.17	1,558
2008	81,365.08	33,067	25,105	56,260	19.72	2,853
2009	733.80	280	213	521	20.29	26
2012	635,369.62	192,517	146,163	489,207	21.85	22,389
2013	1,178,439.47	323,599	245,683	932,757	22.46	41,530
2014	712,349.28	175,808	133,477	578,872	22.89	25,289
2015	626,945.19	136,110	103,337	523,608	23.44	22,338
2016	572,178.48	107,341	81,495	490,683	23.82	20,600
2017	931,132.03	145,815	110,706	820,426	24.24	33,846
2018	663,457.69	82,667	62,762	600,695	24.59	24,428
2019	1,220,473.84	112,039	85,062	1,135,412	24.75	45,875
2020	774,077.28	44,432	33,734	740,344	24.61	30,083
2021	820,156.44	17,223	13,076	807,080	23.31	34,624
	10,247,951.99	2,889,582	2,193,827	8,054,125		406,210
	143,350,207.42	52,222,848	52,248,571	91,101,636		4,532,034

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.1 3.16

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1995	225,308.19	217,918	225,308			
1996	173,108.40	166,426	173,108			
1997	173,127.78	164,991	173,128			
1998	184,130.59	173,525	182,841	1,290	1.44	896
1999	342,667.80	319,983	337,161	5,507	1.60	3,442
2000	478,162.92	440,006	463,628	14,535	1.86	7,815
2001	549,785.70	499,315	526,120	23,665	2.07	11,432
2002	670,198.61	598,554	630,687	39,512	2.33	16,958
2003	252,157.11	221,117	232,988	19,170	2.60	7,373
2004	243,716.21	208,987	220,206	23,510	2.91	8,079
2005	216,895.80	181,086	190,808	26,088	3.26	8,002
2006	5,390,842.80	4,369,817	4,604,409	786,434	3.62	217,247
2008	15,525.65	11,654	12,280	3,246	4.49	723
2018	303,687.22	67,054	70,654	233,033	12.35	18,869
2020	1,511,975.32	143,033	150,712	1,361,264	14.35	94,862
	10,731,290.10	7,783,466	8,194,036	2,537,254		395,698
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
1999	68,566.40	64,027	68,566			
2000	110,387.90	101,579	110,388			
2001	719,557.21	653,502	719,557			
2002	1,586,309.09	1,416,733	1,561,699	24,610	2.33	10,562
2003	887,157.53	777,948	857,551	29,606	2.60	11,387
2004	2,657,385.83	2,278,708	2,511,876	145,510	2.91	50,003
2005	1,150,682.48	960,705	1,059,009	91,674	3.26	28,121
2006	1,163,903.88	943,460	1,039,999	123,905	3.62	34,228
2007	1,417,138.09	1,109,619	1,223,160	193,978	4.02	48,253
2008	490,501.02	368,170	405,843	84,658	4.49	18,855
2009	57,248.17	40,864	45,045	12,203	5.01	2,436
2010	228,321.73	153,615	169,334	58,988	5.59	10,552
2011	246,330.80	154,671	170,498	75,833	6.22	12,192
2012	96,274.94	55,608	61,298	34,977	6.95	5,033
2013	68,490.16	35,916	39,591	28,899	7.71	3,748
2014	7,274.22	3,399	3,747	3,527	8.55	413
2016	42,352.64	14,654	16,153	26,199	10.40	2,519
2018	197,444.20	43,596	48,057	149,387	12.35	12,096

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 381.1 METERS - ERTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2019	24,280.90	3,832	4,224	20,057	13.35	1,502
2020	67,776.24	6,412	7,068	60,708	14.35	4,231
2021	829,106.03	26,200	28,881	800,225	15.35	52,132
	12,116,489.46	9,213,218	10,151,544	1,964,945		308,263
CPG						
SURVIVOR CURVE.. IOWA 17-S3						
NET SALVAGE PERCENT.. 0						
2010	396,383.10	266,687	297,294	99,090	5.59	17,726
2020	5,164.22	489	545	4,619	14.35	322
	401,547.32	267,176	297,839	103,709		18,048
	23,249,326.88	17,263,860	18,643,419	4,605,908		722,009

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.4 3.11

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

UGI-GAS
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1898	1.56	2	2			
1899	45.73	46	46			
1901	125.42	125	125			
1902	190.38	190	190			
1903	207.95	208	208			
1904	192.20	192	192			
1905	295.74	296	296			
1906	171.61	172	172			
1907	447.84	448	448			
1908	194.70	195	195			
1909	5,593.69	5,594	5,594			
1910	1,070.27	1,070	1,070			
1911	2,131.79	2,132	2,132			
1912	1,304.52	1,305	1,305			
1913	1,697.22	1,697	1,697			
1914	1,422.02	1,422	1,422			
1915	1,885.62	1,886	1,886			
1916	2,392.46	2,392	2,392			
1917	3,042.59	3,043	3,043			
1918	2,018.75	2,019	2,019			
1919	9,546.64	9,547	9,547			
1920	13,006.66	13,007	13,007			
1921	10,882.44	10,882	10,882			
1922	11,895.66	11,896	11,896			
1923	13,623.38	13,623	13,623			
1924	16,813.34	16,813	16,813			
1925	17,723.49	17,723	17,723			
1926	11,912.95	11,913	11,913			
1927	13,898.35	13,898	13,898			
1928	12,319.91	12,320	12,320			
1929	12,923.57	12,924	12,924			
1930	7,888.18	7,857	7,888			
1931	6,038.87	5,985	6,039			
1932	4,264.87	4,204	4,265			
1933	2,305.38	2,259	2,305			
1934	2,832.22	2,758	2,832			
1935	3,710.73	3,592	3,711			
1936	3,819.71	3,675	3,820			
1937	6,583.13	6,295	6,583			
1938	5,345.46	5,080	5,345			
1939	6,463.11	6,103	6,463			
1940	8,892.11	8,343	8,892			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1941	10,712.58	9,986	10,713			
1942	8,488.07	7,859	8,488			
1943	6,187.46	5,691	6,187			
1944	8,149.37	7,444	8,149			
1945	8,496.19	7,707	8,496			
1946	13,455.20	12,121	13,454	1	4.56	
1947	28,358.54	25,362	28,152	207	4.86	43
1948	26,549.45	23,571	26,164	386	5.16	75
1949	31,775.41	28,004	31,084	691	5.46	127
1950	37,917.87	33,170	36,818	1,100	5.76	191
1951	43,999.31	38,193	42,394	1,605	6.07	264
1952	48,722.26	41,964	46,580	2,143	6.38	336
1953	42,089.98	35,969	39,925	2,165	6.69	324
1954	57,683.34	48,893	54,271	3,413	7.01	487
1955	71,293.40	59,948	66,542	4,752	7.32	649
1956	77,512.44	64,622	71,730	5,783	7.65	756
1957	80,268.82	66,361	73,660	6,609	7.97	829
1958	75,111.89	61,559	68,330	6,782	8.30	817
1959	81,628.19	66,314	73,608	8,020	8.63	929
1960	78,595.68	63,270	70,229	8,367	8.97	933
1961	67,921.05	54,175	60,134	7,787	9.31	836
1962	60,121.28	47,509	52,735	7,387	9.65	765
1963	69,492.77	54,386	60,368	9,125	10.00	912
1964	78,759.59	61,039	67,753	11,007	10.35	1,063
1965	96,753.54	74,226	82,390	14,363	10.71	1,341
1966	100,525.58	76,334	84,730	15,796	11.07	1,427
1967	110,606.10	83,098	92,238	18,368	11.44	1,606
1968	127,381.10	94,677	105,091	22,291	11.81	1,887
1969	130,558.23	95,960	106,515	24,044	12.19	1,972
1970	115,672.28	84,064	93,310	22,362	12.57	1,779
1971	101,732.53	73,070	81,107	20,626	12.96	1,592
1972	93,455.11	66,333	73,629	19,826	13.35	1,485
1973	127,135.54	89,133	98,937	28,199	13.75	2,051
1974	135,075.88	93,525	103,812	31,264	14.15	2,209
1975	92,936.59	63,520	70,507	22,430	14.56	1,541
1976	48,364.14	32,614	36,201	12,163	14.98	812
1977	83,542.25	55,574	61,687	21,856	15.40	1,419
1978	97,632.01	64,034	71,077	26,555	15.83	1,678
1979	306,516.75	198,102	219,891	86,626	16.27	5,324
1980	578,785.99	368,536	409,071	169,715	16.71	10,156
1981	653,208.51	409,392	454,421	198,788	17.17	11,578
1982	524,387.93	376,982	418,446	105,942	15.45	6,857

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1983	544,482.64	385,712	428,136	116,346	15.85	7,340
1984	476,450.45	334,087	370,833	105,617	15.98	6,609
1985	668,713.44	461,279	512,015	156,698	16.41	9,549
1986	684,038.52	463,778	514,789	169,250	16.86	10,039
1987	765,418.74	509,616	565,669	199,750	17.32	11,533
1988	985,892.19	647,337	718,538	267,355	17.52	15,260
1989	1,070,134.50	688,632	764,375	305,760	18.01	16,977
1990	1,334,644.62	845,097	938,049	396,595	18.25	21,731
1991	1,328,153.09	822,392	912,847	415,306	18.76	22,138
1992	1,244,966.55	756,566	839,781	405,186	19.04	21,281
1993	967,023.30	573,251	636,303	330,720	19.58	16,891
1994	1,371,891.22	795,971	883,520	488,371	19.90	24,541
1995	1,516,299.40	855,799	949,928	566,371	20.45	27,695
1996	1,411,075.57	777,220	862,706	548,369	20.80	26,364
1997	1,661,272.15	891,439	989,488	671,784	21.16	31,748
1998	1,836,056.22	957,871	1,063,227	772,829	21.55	35,862
1999	1,801,930.71	908,173	1,008,063	793,868	22.14	35,857
2000	1,835,296.69	895,625	994,135	841,162	22.56	37,286
2001	1,780,558.22	839,533	931,873	848,685	22.98	36,931
2002	1,029,425.71	467,771	519,221	510,205	23.42	21,785
2003	1,431,100.42	624,818	693,542	737,559	23.87	30,899
2004	1,123,563.48	469,874	521,555	602,008	24.34	24,733
2005	1,297,983.39	516,078	572,841	725,142	25.00	29,006
2006	1,361,922.07	515,079	571,732	790,190	25.48	31,012
2007	7,191,674.98	2,576,058	2,859,398	4,332,277	25.98	166,754
2008	3,024,995.30	1,020,936	1,133,229	1,891,767	26.50	71,387
2009	2,217,742.35	701,250	778,380	1,439,362	27.03	53,251
2010	1,438,403.59	423,466	470,043	968,361	27.56	35,136
2011	1,800,694.03	487,808	541,462	1,259,232	28.26	44,559
2012	2,221,300.70	550,883	611,475	1,609,826	28.81	55,877
2013	2,737,348.87	612,071	679,393	2,057,956	29.52	69,714
2014	2,031,120.21	405,208	449,777	1,581,343	30.09	52,554
2015	2,708,188.69	471,766	523,656	2,184,533	30.81	70,903
2016	2,890,225.25	429,198	476,405	2,413,820	31.54	76,532
2017	2,912,602.40	356,503	395,715	2,516,888	32.26	78,019
2018	3,947,225.70	378,539	420,174	3,527,051	33.00	106,880
2019	2,997,774.63	206,247	228,932	2,768,843	33.86	81,773
2020	3,215,895.46	133,138	147,782	3,068,114	34.73	88,342
2021	5,478,233.02	75,600	83,915	5,394,318	35.60	151,526
	81,206,400.89	28,381,091	31,479,046	49,727,355		1,823,324

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1953	3,957.44	3,382	1,705	2,253	6.69	337
1954	4,992.73	4,232	2,133	2,859	7.01	408
1955	6,749.65	5,676	2,861	3,888	7.32	531
1956	4,652.22	3,879	1,955	2,697	7.65	353
1957	12,571.25	10,393	5,239	7,332	7.97	920
1958	13,680.75	11,212	5,652	8,029	8.30	967
1959	14,163.78	11,507	5,800	8,363	8.63	969
1960	5,694.50	4,584	2,311	3,384	8.97	377
1961	14,608.05	11,652	5,874	8,734	9.31	938
1962	12,029.24	9,506	4,792	7,237	9.65	750
1963	12,504.21	9,786	4,933	7,571	10.00	757
1964	15,578.78	12,074	6,086	9,492	10.35	917
1965	23,775.80	18,240	9,194	14,581	10.71	1,361
1966	17,604.09	13,368	6,739	10,866	11.07	982
1967	20,893.24	15,697	7,913	12,981	11.44	1,135
1968	27,322.42	20,308	10,237	17,085	11.81	1,447
1969	19,661.37	14,451	7,285	12,377	12.19	1,015
1970	37,507.92	27,259	13,741	23,767	12.57	1,891
1971	23,762.64	17,068	8,604	15,159	12.96	1,170
1972	20,513.54	14,560	7,339	13,174	13.35	987
1973	10,455.25	7,330	3,695	6,760	13.75	492
1974	80,178.92	55,515	27,984	52,195	14.15	3,689
1975	19,775.07	13,516	6,813	12,962	14.56	890
1976	4,380.86	2,954	1,489	2,892	14.98	193
1977	1,334.44	888	448	887	15.40	58
1978	110.82	73	37	74	15.83	5
1979	952.25	615	310	642	16.27	39
1980	13,634.97	8,682	4,376	9,259	16.71	554
1981	35,806.28	22,441	11,312	24,494	17.17	1,427
1982	32,976.06	23,706	11,950	21,026	15.45	1,361
1983	30,298.97	21,464	10,820	19,479	15.85	1,229
1984	31,176.75	21,861	11,020	20,157	15.98	1,261
1985	53,622.36	36,989	18,646	34,977	16.41	2,131
1986	58,717.94	39,811	20,068	38,650	16.86	2,292
1987	74,450.88	49,569	24,987	49,464	17.32	2,856
1988	57,001.64	37,427	18,866	38,135	17.52	2,177
1989	79,399.51	51,094	25,756	53,644	18.01	2,979
1990	83,514.40	52,881	26,656	56,858	18.25	3,116
1991	86,051.49	53,283	26,859	59,192	18.76	3,155
1992	70,069.58	42,581	21,464	48,605	19.04	2,553

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 382 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1993	76,473.21	45,333	22,852	53,622	19.58	2,739
1994	102,807.08	59,649	30,068	72,739	19.90	3,655
1995	111,230.16	62,778	31,645	79,585	20.45	3,892
1996	206,710.67	113,856	57,393	149,318	20.80	7,179
1997	304,799.73	163,556	82,446	222,354	21.16	10,508
1998	541,757.58	282,635	142,472	399,286	21.55	18,528
1999	411,867.44	207,581	104,638	307,229	22.14	13,877
2000	393,232.16	191,897	96,732	296,500	22.56	13,143
2001	344,751.63	162,550	81,939	262,813	22.98	11,437
2002	453,491.35	206,066	103,874	349,617	23.42	14,928
2003	351,177.59	153,324	77,288	273,890	23.87	11,474
2004	244,795.45	102,373	51,605	193,191	24.34	7,937
2005	429,337.66	170,705	86,050	343,288	25.00	13,732
2006	299,300.78	113,196	57,060	242,241	25.48	9,507
2007	647,783.38	232,036	116,965	530,818	25.98	20,432
2008	814,605.24	274,929	138,587	676,018	26.50	25,510
2009	474,325.74	149,982	75,603	398,722	27.03	14,751
2010	330,126.13	97,189	48,991	281,135	27.56	10,201
2011	619,301.32	167,769	84,570	534,732	28.26	18,922
2012	572,709.73	142,032	71,596	501,114	28.81	17,394
2013	632,492.13	141,425	71,290	561,202	29.52	19,011
2014	755,842.89	150,791	76,011	679,832	30.09	22,593
2015	1,063,981.95	185,346	93,430	970,552	30.81	31,501
2016	2,028,590.94	301,246	151,853	1,876,738	31.54	59,503
2017	650,849.97	79,664	40,157	610,693	32.26	18,930
2018	757,648.03	72,658	36,626	721,022	33.00	21,849
2019	1,538,369.53	105,840	53,352	1,485,017	33.86	43,858
2020	484,367.12	20,053	10,108	474,259	34.73	13,656
2021	357,011.97	4,927	2,484	354,528	35.60	9,959
	17,135,870.62	4,942,900	2,491,633	14,644,238		541,275
	98,342,271.51	33,323,991	33,970,678	64,371,593		2,364,599

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.2 2.40

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

UGI-GAS
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1944	77.95	71	64	14	3.98	4
1957	117.06	97	87	30	7.97	4
1962	2,151.47	1,700	1,521	630	9.65	65
1964	17,920.86	13,889	12,430	5,491	10.35	531
1965	20,920.63	16,050	14,364	6,557	10.71	612
1966	29,758.73	22,597	20,223	9,536	11.07	861
1967	33,875.31	25,451	22,777	11,098	11.44	970
1968	27,894.47	20,733	18,555	9,340	11.81	791
1969	29,312.36	21,545	19,281	10,031	12.19	823
1970	46,449.79	33,757	30,210	16,240	12.57	1,292
1971	42,432.58	30,478	27,276	15,157	12.96	1,170
1972	30,600.18	21,719	19,437	11,163	13.35	836
1973	21,528.93	15,094	13,508	8,021	13.75	583
1974	24,295.63	16,822	15,055	9,241	14.15	653
1975	33,447.98	22,861	20,459	12,989	14.56	892
1976	7,088.04	4,780	4,278	2,810	14.98	188
1977	17,783.83	11,830	10,587	7,197	15.40	467
1978	23,253.21	15,251	13,649	9,605	15.83	607
1979	85,124.85	55,016	49,236	35,889	16.27	2,206
1980	175,119.76	111,506	99,790	75,329	16.71	4,508
1981	85,224.43	53,414	47,802	37,423	17.17	2,180
1982	129,428.81	93,046	83,270	46,159	15.45	2,988
1983	63,138.87	44,728	40,029	23,110	15.85	1,458
1984	58,876.10	41,284	36,946	21,930	15.98	1,372
1985	123,384.92	85,111	76,169	47,216	16.41	2,877
1986	140,377.12	95,176	85,176	55,201	16.86	3,274
1987	136,832.49	91,103	81,531	55,301	17.32	3,193
1988	175,491.48	115,228	103,121	72,370	17.52	4,131
1989	213,503.89	137,390	122,955	90,549	18.01	5,028
1990	214,130.92	135,588	121,342	92,789	18.25	5,084
1991	78,271.51	48,466	43,374	34,898	18.76	1,860
1992	96,689.87	58,758	52,584	44,105	19.04	2,316
1993	33,962.96	20,133	18,018	15,945	19.58	814
1994	111,740.54	64,832	58,020	53,720	19.90	2,699
1995	158,945.89	89,709	80,283	78,662	20.45	3,847
1996	44,731.50	24,638	22,049	22,682	20.80	1,090
1997	90,392.75	48,505	43,409	46,984	21.16	2,220
1998	55,905.23	29,166	26,102	29,804	21.55	1,383
1999	104,475.10	52,655	47,123	57,352	22.14	2,590
2000	92,875.32	45,323	40,561	52,314	22.56	2,319
2001	170,338.61	80,315	71,876	98,462	22.98	4,285
2002	54,814.24	24,908	22,291	32,523	23.42	1,389

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2003	133,190.26	58,151	52,041	81,149	23.87	3,400
2004	229,781.29	96,095	85,999	143,783	24.34	5,907
2005	221,319.48	87,997	78,751	142,568	25.00	5,703
2006	179,516.35	67,893	60,760	118,757	25.48	4,661
2008	542,890.68	183,226	163,975	378,916	26.50	14,299
2009	435,453.99	137,691	123,224	312,230	27.03	11,551
2010	540,142.20	159,018	142,310	397,832	27.56	14,435
2012	185,684.69	46,050	41,212	144,473	28.81	5,015
2013	64,891.21	14,510	12,985	51,906	29.52	1,758
2020	588,929.84	24,382	21,820	567,110	34.73	16,329
2021	64,272.16	887	794	63,478	35.60	1,783
	6,288,758.32	2,816,623	2,520,687	3,768,072		161,301
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1950	211.54	185	212			
1952	22,872.17	19,700	22,872			
1953	3,324.65	2,841	3,325			
1954	3,638.77	3,084	3,639			
1956	2,288.98	1,908	2,289			
1957	4,312.96	3,566	4,313			
1958	523.27	429	523			
1959	5,076.98	4,124	5,077			
1960	13,576.34	10,929	13,576			
1961	9,266.15	7,391	9,266			
1962	28,692.16	22,673	28,692			
1963	14,471.10	11,325	14,471			
1964	37,803.93	29,298	37,804			
1965	38,378.73	29,443	38,379			
1966	31,246.60	23,727	31,247			
1967	24,202.13	18,183	24,202			
1968	19,889.94	14,783	19,890			
1969	19,954.10	14,666	19,770	184	12.19	15
1970	22,762.73	16,543	22,300	462	12.57	37
1971	20,289.92	14,573	19,645	645	12.96	50
1972	17,294.88	12,276	16,548	747	13.35	56
1973	11,492.55	8,057	10,861	632	13.75	46
1974	24,418.58	16,907	22,791	1,628	14.15	115

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1975	16,319.18	11,154	15,036	1,283	14.56	88
1976	25,023.29	16,874	22,747	2,277	14.98	152
1977	43,118.59	28,683	38,665	4,453	15.40	289
1978	25,979.99	17,039	22,969	3,011	15.83	190
1979	50,315.47	32,519	43,836	6,479	16.27	398
1980	157,640.32	100,376	135,309	22,331	16.71	1,336
1981	85,258.09	53,435	72,031	13,227	17.17	770
1984	251.00	176	237	14	15.98	1
1985	76,948.28	53,079	71,552	5,397	16.41	329
1986	6,297.30	4,270	5,756	541	16.86	32
1987	4,517.67	3,008	4,055	463	17.32	27
1988	436.80	287	387	50	17.52	3
1989	61,414.76	39,520	53,274	8,141	18.01	452
1990	113,229.49	71,697	96,649	16,580	18.25	908
1991	3,009.98	1,864	2,513	497	18.76	26
1992	70,156.42	42,634	57,472	12,685	19.04	666
1993	67,108.70	39,782	53,627	13,482	19.58	689
1994	82,593.19	47,921	64,599	17,995	19.90	904
1995	26,780.69	15,115	20,375	6,405	20.45	313
1996	1,225.32	675	910	315	20.80	15
1997	216,693.86	116,278	156,745	59,949	21.16	2,833
1998	256,742.97	133,943	180,558	76,185	21.55	3,535
1999	8,429.94	4,249	5,728	2,702	22.14	122
2000	84,587.64	41,279	55,645	28,943	22.56	1,283
2001	118,361.21	55,807	75,229	43,132	22.98	1,877
2002	169,552.53	77,045	103,858	65,694	23.42	2,805
2003	148,288.73	64,743	87,275	61,014	23.87	2,556
2004	220,104.20	92,048	124,083	96,022	24.34	3,945
2007	122,142.22	43,751	58,977	63,165	25.98	2,431
2009	114,064.35	36,067	48,619	65,445	27.03	2,421
2010	62,519.49	18,406	24,812	37,708	27.56	1,368
2018	45.98	4	5	41	33.00	1
2021	6,060.89	84	113	5,948	35.60	167
	2,821,207.70	1,550,423	2,075,337	745,871		33,251

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1971	5,001.66	3,592	4,829	172	12.96	13
1972	12,065.77	8,564	11,514	552	13.35	41
1973	16,158.21	11,328	15,230	928	13.75	67
1974	23,610.65	16,348	21,980	1,631	14.15	115
1975	11,934.41	8,157	10,967	967	14.56	66
1976	6,620.80	4,465	6,003	618	14.98	41
1977	3,884.68	2,584	3,474	411	15.40	27
1978	5,230.27	3,430	4,612	619	15.83	39
1979	5,706.05	3,688	4,958	748	16.27	46
1980	25,223.43	16,061	21,594	3,630	16.71	217
1981	21,935.83	13,748	18,484	3,452	17.17	201
1982	13,794.39	9,917	13,333	461	15.45	30
1983	18,523.58	13,122	17,642	881	15.85	56
1984	29,007.23	20,340	27,347	1,660	15.98	104
1985	25,172.95	17,364	23,346	1,827	16.41	111
1986	27,049.72	18,340	24,658	2,392	16.86	142
1987	27,469.49	18,289	24,589	2,880	17.32	166
1988	27,188.25	17,852	24,002	3,186	17.52	182
1989	33,227.77	21,382	28,748	4,480	18.01	249
1990	49,270.86	31,198	41,945	7,325	18.25	401
1991	52,753.58	32,665	43,918	8,836	18.76	471
1992	51,222.02	31,128	41,851	9,371	19.04	492
1993	54,594.81	32,364	43,513	11,082	19.58	566
1994	58,410.15	33,890	45,565	12,845	19.90	645
1995	72,041.99	40,660	54,667	17,375	20.45	850
1996	66,567.19	36,665	49,296	17,271	20.80	830
1997	69,627.81	37,362	50,233	19,395	21.16	917
1998	43,091.97	22,481	30,225	12,866	21.55	597
1999	67,928.48	34,236	46,030	21,899	22.14	989
2000	15,193.15	7,414	9,968	5,225	22.56	232
2001	23,579.10	11,118	14,948	8,631	22.98	376
2002	27,373.31	12,438	16,723	10,651	23.42	455
2003	3,465.46	1,513	2,034	1,431	23.87	60
2004	30,509.32	12,759	17,154	13,355	24.34	549
2005	306.93	122	164	143	25.00	6
2006	27,857.50	10,536	14,166	13,692	25.48	537
2007	1,442.16	517	695	747	25.98	29
2008	23,307.67	7,866	10,576	12,732	26.50	480
2009	15,660.01	4,952	6,658	9,002	27.03	333
2010	25,708.61	7,569	10,176	15,532	27.56	564
2011	17,915.17	4,853	6,525	11,390	28.26	403
2012	25,078.47	6,219	8,361	16,717	28.81	580

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 383 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2013	43,118.70	9,641	12,962	30,156	29.52	1,022
2014	31,965.64	6,377	8,574	23,392	30.09	777
2015	28,084.77	4,892	6,577	21,508	30.81	698
2016	18,472.15	2,743	3,688	14,784	31.54	469
2017	39,903.87	4,884	6,566	33,337	32.26	1,033
2018	118,886.13	11,401	15,329	103,558	33.00	3,138
2019	2,661.73	183	246	2,416	33.86	71
2020	28,754.03	1,190	1,600	27,154	34.73	782
2021	22,635.63	312	419	22,216	35.60	624
	1,496,193.51	690,719	928,665	567,529		21,889
	10,606,159.53	5,057,765	5,524,688	5,081,472		216,441

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.5 2.04

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1906	735.52	736	736			
1907	1,604.70	1,605	1,605			
1908	743.19	743	743			
1909	1,074.39	1,074	1,074			
1910	441.82	442	442			
1911	956.52	957	957			
1912	1,237.26	1,237	1,237			
1913	1,082.10	1,082	1,082			
1914	1,094.15	1,094	1,094			
1915	693.49	693	693			
1916	1,326.49	1,326	1,326			
1917	1,494.31	1,494	1,494			
1918	885.50	886	886			
1919	1,301.37	1,301	1,301			
1920	1,254.20	1,254	1,254			
1921	1,846.30	1,846	1,846			
1922	3,116.86	3,117	3,117			
1923	4,440.67	4,441	4,441			
1924	4,536.34	4,536	4,536			
1925	4,740.02	4,740	4,740			
1926	4,283.39	4,283	4,283			
1927	4,198.07	4,198	4,198			
1928	3,336.56	3,337	3,337			
1929	3,791.62	3,792	3,792			
1930	2,650.70	2,640	2,651			
1931	2,127.85	2,109	2,128			
1932	1,072.18	1,057	1,072			
1933	927.84	909	928			
1934	1,097.63	1,069	1,098			
1935	1,167.61	1,130	1,168			
1936	1,503.95	1,447	1,504			
1937	1,975.00	1,889	1,975			
1938	1,557.60	1,480	1,558			
1939	1,529.07	1,444	1,529			
1940	1,723.92	1,617	1,723	1	2.84	
1941	2,114.59	1,971	2,100	14	3.12	4
1942	1,842.70	1,706	1,818	25	3.41	7
1943	1,208.64	1,112	1,185	24	3.69	7
1944	2,349.55	2,146	2,287	63	3.98	16
1945	2,610.08	2,368	2,523	87	4.27	20
1946	4,010.12	3,613	3,850	160	4.56	35
1947	8,617.38	7,707	8,212	405	4.86	83

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

UGI-GAS
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1948	8,291.44	7,361	7,843	448	5.16	87
1949	9,552.15	8,418	8,970	582	5.46	107
1950	9,982.32	8,732	9,304	678	5.76	118
1951	13,038.83	11,318	12,060	979	6.07	161
1952	13,567.61	11,686	12,452	1,116	6.38	175
1953	10,972.19	9,377	9,992	981	6.69	147
1954	9,249.44	7,840	8,354	896	7.01	128
1955	15,034.66	12,642	13,471	1,564	7.32	214
1956	19,281.23	16,075	17,129	2,153	7.65	281
1957	21,137.24	17,475	18,620	2,517	7.97	316
1958	20,116.82	16,487	17,568	2,549	8.30	307
1959	28,562.71	23,204	24,725	3,838	8.63	445
1960	21,465.56	17,280	18,413	3,053	8.97	340
1961	14,225.79	11,347	12,091	2,135	9.31	229
1962	14,665.22	11,589	12,349	2,317	9.65	240
1963	17,923.60	14,027	14,946	2,977	10.00	298
1964	20,338.28	15,762	16,795	3,543	10.35	342
1965	21,381.43	16,403	17,478	3,903	10.71	364
1966	22,763.29	17,285	18,418	4,345	11.07	393
1967	24,496.78	18,404	19,610	4,886	11.44	427
1968	29,207.32	21,709	23,132	6,075	11.81	514
1969	30,163.40	22,170	23,623	6,540	12.19	537
1970	24,709.76	17,958	19,135	5,575	12.57	444
1971	32,099.03	23,055	24,566	7,533	12.96	581
1972	38,136.64	27,069	28,843	9,293	13.35	696
1973	46,699.12	32,740	34,886	11,813	13.75	859
1974	41,287.45	28,587	30,461	10,827	14.15	765
1975	28,525.71	19,497	20,775	7,751	14.56	532
1976	20,710.12	13,966	14,881	5,829	14.98	389
1977	30,396.78	20,221	21,546	8,850	15.40	575
1978	40,769.14	26,739	28,492	12,278	15.83	776
1979	68,832.87	44,487	47,403	21,430	16.27	1,317
1980	131,408.86	83,673	89,157	42,251	16.71	2,528
1981	110,631.00	69,337	73,882	36,749	17.17	2,140
1982	190,335.00	136,832	145,801	44,534	15.45	2,882
1983	141,533.91	100,263	106,835	34,699	15.85	2,189
1984	96,589.58	67,729	72,168	24,421	15.98	1,528
1985	157,339.96	108,533	115,647	41,693	16.41	2,541
1986	142,951.52	96,921	103,274	39,678	16.86	2,353
1987	168,313.63	112,063	119,408	48,905	17.32	2,824
1988	176,855.08	116,123	123,734	53,121	17.52	3,032
1989	245,809.88	158,179	168,547	77,263	18.01	4,290

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1990	200,239.89	126,792	135,103	65,137	18.25	3,569
1991	127,914.76	79,205	84,397	43,518	18.76	2,320
1992	194,224.55	118,030	125,766	68,458	19.04	3,595
1993	110,374.14	65,430	69,719	40,656	19.58	2,076
1994	159,243.25	92,393	98,449	60,794	19.90	3,055
1995	225,556.84	127,304	135,648	89,909	20.45	4,397
1996	146,163.86	80,507	85,784	60,380	20.80	2,903
1997	183,670.61	98,558	105,018	78,653	21.16	3,717
1998	242,997.43	126,772	135,081	107,916	21.55	5,008
1999	163,009.46	82,157	87,542	75,467	22.14	3,409
2000	129,708.02	63,298	67,447	62,261	22.56	2,760
2001	175,354.91	82,680	88,099	87,256	22.98	3,797
2002	178,137.48	80,946	86,252	91,886	23.42	3,923
2003	463,652.54	202,431	215,699	247,953	23.87	10,388
2004	582,927.65	243,780	259,759	323,169	24.34	13,277
2005	461,613.81	183,538	195,568	266,046	25.00	10,642
2006	271,218.43	102,575	109,298	161,920	25.48	6,355
2008	801,363.82	270,460	288,187	513,176	26.50	19,365
2009	189,343.07	59,870	63,794	125,549	27.03	4,645
2010	213,698.43	62,913	67,037	146,662	27.56	5,322
2011	310,820.65	84,201	89,720	221,101	28.26	7,824
2012	514,236.52	127,531	135,890	378,346	28.81	13,132
2013	418,060.32	93,478	99,605	318,455	29.52	10,788
2014	466,917.86	93,150	99,256	367,662	30.09	12,219
2015	456,957.65	79,602	84,820	372,138	30.81	12,078
2016	686,364.70	101,925	108,606	577,759	31.54	18,318
2017	746,787.10	91,407	97,398	649,389	32.26	20,130
2018	883,633.27	84,740	90,294	793,339	33.00	24,041
2019	540,805.30	37,207	39,646	501,160	33.86	14,801
2020	217,197.00	8,992	9,581	207,616	34.73	5,978
2021	274,637.46	3,790	4,038	270,599	35.60	7,601
	13,156,484.38	4,863,853	5,178,806	7,977,678		301,016
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1959	245.76	200	246			
1960	2,151.30	1,732	2,151			
1961	75,690.37	60,371	75,690			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

PNG
SURVIVOR CURVE.. IOWA 46-S1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1962	16,927.20	13,376	16,927			
1963	22,943.49	17,956	22,943			
1964	28,400.21	22,010	28,400			
1965	29,395.47	22,551	29,395			
1966	36,408.56	27,647	36,219	189	11.07	17
1967	32,174.73	24,173	31,668	507	11.44	44
1968	26,931.71	20,017	26,223	708	11.81	60
1969	37,722.84	27,726	36,323	1,400	12.19	115
1970	19,650.04	14,280	18,708	942	12.57	75
1971	9,667.21	6,944	9,097	570	12.96	44
1972	13,313.98	9,450	12,380	934	13.35	70
1973	38,836.17	27,228	35,670	3,166	13.75	230
1974	144,406.45	99,986	130,987	13,419	14.15	948
1975	99,258.76	67,841	88,876	10,383	14.56	713
1976	162,178.02	109,365	143,275	18,904	14.98	1,262
1977	227,638.93	151,430	198,382	29,257	15.40	1,900
1978	126,268.54	82,816	108,494	17,775	15.83	1,123
1979	78,656.93	50,836	66,598	12,059	16.27	741
1980	57,030.55	36,314	47,573	9,457	16.71	566
1981	109,907.92	68,884	90,242	19,666	17.17	1,145
1985	24,654.43	17,007	22,280	2,374	16.41	145
1986	27,447.15	18,609	24,379	3,068	16.86	182
1988	68,000.86	44,649	58,493	9,508	17.52	543
1989	58,448.77	37,612	49,274	9,175	18.01	509
1990	51,140.66	32,382	42,422	8,718	18.25	478
1991	39,011.61	24,156	31,646	7,366	18.76	393
1992	35,854.73	21,789	28,545	7,310	19.04	384
1993	51,676.44	30,634	40,132	11,544	19.58	590
1994	71,235.62	41,331	54,146	17,090	19.90	859
1995	49,500.84	27,938	36,600	12,900	20.45	631
1996	45,909.70	25,287	33,127	12,782	20.80	615
1997	34,534.58	18,531	24,277	10,258	21.16	485
1998	49,970.37	26,070	34,153	15,817	21.55	734
1999	46,832.83	23,604	30,923	15,910	22.14	719
2000	39,699.21	19,373	25,380	14,319	22.56	635
2001	45,124.99	21,276	27,873	17,252	22.98	751
2002	66,517.98	30,226	39,598	26,920	23.42	1,149
2003	78,667.19	34,346	44,995	33,672	23.87	1,411
2004	165,793.01	69,335	90,833	74,960	24.34	3,080
2005	119,365.27	47,460	62,175	57,190	25.00	2,288
2006	70,424.87	26,635	34,893	35,531	25.48	1,394
2007	93,502.87	33,493	43,878	49,625	25.98	1,910

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2008	109,845.80	37,073	48,568	61,278	26.50	2,312
2009	119,208.92	37,694	49,381	69,828	27.03	2,583
2010	90,572.74	26,665	34,933	55,640	27.56	2,019
2011	78,430.71	21,247	27,835	50,596	28.26	1,790
2012	113,394.32	28,122	36,841	76,553	28.81	2,657
2013	103,879.46	23,227	30,429	73,451	29.52	2,488
2014	114,396.21	22,822	29,898	84,498	30.09	2,808
2015	113,875.06	19,837	25,988	87,887	30.81	2,853
2016	95,701.05	14,212	18,619	77,083	31.54	2,444
2017	26,020.32	3,185	4,173	21,848	32.26	677
2018	56,220.18	5,392	7,064	49,156	33.00	1,490
2019	45,274.31	3,115	4,081	41,193	33.86	1,217
2020	1,226.17	51	67	1,159	34.73	33
2021	447.76	6	8	440	35.60	12
	3,797,612.13	1,877,524	2,454,375	1,343,238		54,321
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1965	1,895.12	1,454	1,670	225	10.71	21
1966	4,989.88	3,789	4,352	638	11.07	58
1967	7,905.20	5,939	6,822	1,083	11.44	95
1968	7,544.59	5,608	6,442	1,103	11.81	93
1969	7,037.34	5,172	5,941	1,096	12.19	90
1970	6,684.62	4,858	5,580	1,104	12.57	88
1971	4,822.66	3,464	3,979	844	12.96	65
1972	5,439.90	3,861	4,435	1,005	13.35	75
1973	14,933.80	10,470	12,027	2,907	13.75	211
1974	7,861.73	5,443	6,252	1,609	14.15	114
1975	9,613.04	6,570	7,547	2,066	14.56	142
1976	4,932.44	3,326	3,821	1,112	14.98	74
1977	4,347.30	2,892	3,322	1,025	15.40	67
1978	3,525.43	2,312	2,656	870	15.83	55
1979	2,829.16	1,828	2,100	729	16.27	45
1980	3,571.30	2,274	2,612	959	16.71	57
1981	10,155.76	6,365	7,311	2,844	17.17	166
1982	8,768.97	6,304	7,241	1,528	15.45	99
1983	7,863.13	5,570	6,398	1,465	15.85	92
1984	27,433.37	19,236	22,096	5,337	15.98	334

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1985	14,612.72	10,080	11,579	3,034	16.41	185
1986	17,814.51	12,078	13,874	3,941	16.86	234
1987	8,715.77	5,803	6,666	2,050	17.32	118
1988	6,897.76	4,529	5,202	1,695	17.52	97
1989	18,499.00	11,904	13,674	4,825	18.01	268
1990	17,820.76	11,284	12,962	4,859	18.25	266
1991	13,760.77	8,521	9,788	3,973	18.76	212
1992	16,073.60	9,768	11,220	4,853	19.04	255
1993	6,559.93	3,889	4,467	2,093	19.58	107
1994	29,217.11	16,952	19,472	9,745	19.90	490
1995	25,165.33	14,203	16,315	8,851	20.45	433
1996	58,774.81	32,373	37,186	21,589	20.80	1,038
1997	115,510.48	61,983	71,198	44,312	21.16	2,094
1998	69,851.40	36,441	41,859	27,992	21.55	1,299
1999	54,506.47	27,471	31,555	22,951	22.14	1,037
2000	47,330.67	23,097	26,531	20,800	22.56	922
2001	65,564.04	30,913	35,509	30,055	22.98	1,308
2002	94,751.21	43,055	49,456	45,295	23.42	1,934
2003	27,748.85	12,115	13,916	13,833	23.87	580
2004	181,730.07	76,000	87,299	94,431	24.34	3,880
2005	3,879.80	1,543	1,772	2,107	25.00	84
2006	111,923.85	42,330	48,624	63,300	25.48	2,484
2007	9,306.75	3,334	3,830	5,477	25.98	211
2008	78,534.49	26,505	30,446	48,089	26.50	1,815
2009	77,935.00	24,643	28,307	49,628	27.03	1,836
2010	77,881.91	22,928	26,337	51,545	27.56	1,870
2011	36,000.84	9,753	11,203	24,798	28.26	877
2012	9,612.23	2,384	2,738	6,874	28.81	239
2013	1,472.30	329	378	1,094	29.52	37
2014	2,742.40	547	628	2,114	30.09	70
2015	4,238.77	738	848	3,391	30.81	110
2016	13,257.55	1,969	2,262	10,996	31.54	349
2017	6,407.77	784	901	5,507	32.26	171
2018	19,731.53	1,892	2,173	17,558	33.00	532

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 384 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
2019	1,948.17	134	154	1,794	33.86	53
2020	29,120.23	1,206	1,385	27,735	34.73	799
2021	20,518.00	283	325	20,193	35.60	567
	1,547,571.59	700,496	804,644	742,928		30,902
	18,501,668.10	7,441,873	8,437,825	10,063,844		386,239

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.1 2.09

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1953	691.53	628	692			
1956	2,239.85	1,990	2,240			
1957	4,785.87	4,222	4,786			
1960	16,750.58	14,443	16,690	61	6.20	10
1961	12,800.59	10,949	12,652	148	6.51	23
1962	22,033.72	18,694	21,602	432	6.82	63
1963	24,186.10	20,348	23,513	673	7.14	94
1964	21,937.83	18,296	21,142	796	7.47	107
1965	14,345.92	11,856	13,700	646	7.81	83
1966	22,819.15	18,686	21,593	1,227	8.15	151
1967	33,625.63	27,274	31,516	2,109	8.50	248
1968	78,227.64	62,808	72,578	5,650	8.87	637
1969	79,698.42	63,334	73,185	6,513	9.24	705
1970	56,628.40	44,510	51,433	5,195	9.63	539
1971	50,484.00	39,232	45,334	5,150	10.03	513
1972	74,487.40	57,206	66,104	8,383	10.44	803
1973	5,856.45	4,443	5,134	722	10.86	66
1974	2,435.60	1,824	2,108	328	11.30	29
1975	3,447.78	2,548	2,944	503	11.75	43
1976	1,925.80	1,403	1,621	305	12.21	25
1979	129,595.68	90,199	104,229	25,366	13.68	1,854
1980	273,942.52	187,560	216,735	57,208	14.19	4,032
1981	280,781.60	188,935	218,323	62,458	14.72	4,243
1982	232,089.47	172,350	199,159	32,931	13.69	2,405
1983	89,210.82	65,258	75,409	13,802	14.13	977
1984	47,248.78	34,019	39,311	7,938	14.58	544
1985	101,055.89	71,558	82,689	18,367	15.05	1,220
1986	78,585.49	54,680	63,185	15,400	15.52	992
1987	157,570.97	107,637	124,380	33,191	16.01	2,073
1988	283,620.35	190,026	219,584	64,036	16.50	3,881
1989	183,420.00	120,415	139,145	44,275	17.00	2,604
1990	203,975.86	131,075	151,463	52,512	17.52	2,997
1991	221,578.38	139,218	160,873	60,705	18.04	3,365
1992	121,714.83	74,684	86,301	35,414	18.58	1,906
1993	67,829.07	40,596	46,911	20,918	19.12	1,094
1994	215,739.93	125,776	145,340	70,400	19.67	3,579
1995	283,678.95	160,874	185,898	97,781	20.23	4,833
1996	638,322.65	351,588	406,277	232,046	20.80	11,156
1997	114,991.22	61,417	70,970	44,021	21.37	2,060
1998	89,135.98	46,083	53,251	35,885	21.95	1,635
1999	211,901.85	105,845	122,309	89,593	22.55	3,973
2000	61,111.51	29,566	34,165	26,947	22.94	1,175

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2001	5,688.76	2,648	3,060	2,629	23.55	112
2002	124,248.21	55,489	64,120	60,128	24.17	2,488
2005	16,976.59	6,611	7,639	9,337	25.87	361
2007	36,240.36	12,662	14,632	21,609	27.00	800
2008	123,273.33	40,606	46,922	76,351	27.48	2,778
2012	13,100.09	3,186	3,682	9,419	29.56	319
2014	217,660.91	42,923	49,600	168,061	30.52	5,507
2015	137,276.88	23,831	27,538	109,739	30.95	3,546
2016	122,361.10	18,305	21,152	101,209	31.26	3,238
2017	414,834.73	51,688	59,728	355,107	31.60	11,238
2018	224,701.21	22,245	25,705	198,996	31.84	6,250
2019	903,092.59	65,926	76,181	826,912	31.75	26,044
2020	3,023,610.46	137,877	159,324	2,864,287	31.39	91,248
2021	1,049,172.82	17,416	20,125	1,029,048	29.62	34,742
	11,028,748.10	3,475,466	4,015,881	7,012,867		255,408
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1954	860.15	775	860			
1956	7,054.30	6,269	7,054			
1957	11,192.51	9,874	11,193			
1958	5,050.93	4,422	5,051			
1959	689.61	599	690			
1960	32,725.24	28,216	32,725			
1961	10,605.59	9,071	10,606			
1962	22,867.17	19,401	22,867			
1963	60,787.04	51,142	60,787			
1964	79,108.77	65,977	79,109			
1965	131,939.84	109,040	131,940			
1966	124,040.09	101,575	123,159	881	8.15	108
1967	208,085.37	168,780	204,645	3,441	8.50	405
1968	233,579.88	187,539	227,390	6,190	8.87	698
1969	194,219.76	154,341	187,137	7,082	9.24	766
1970	271,294.84	213,238	258,550	12,745	9.63	1,323
1971	229,764.59	178,552	216,493	13,271	10.03	1,323
1972	257,964.38	198,117	240,216	17,749	10.44	1,700
1973	109,357.30	82,966	100,596	8,762	10.86	807
1974	90,753.81	67,965	82,407	8,347	11.30	739

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

PNG
SURVIVOR CURVE.. IOWA 45-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1975	52,979.89	39,146	47,464	5,516	11.75	469
1976	53,093.99	38,688	46,909	6,185	12.21	507
1977	29,803.40	21,399	25,946	3,857	12.69	304
1978	50,738.04	35,877	43,501	7,237	13.18	549
1979	92,133.69	64,125	77,751	14,383	13.68	1,051
1980	491,009.86	336,180	407,616	83,394	14.19	5,877
1981	230,826.16	155,321	188,326	42,500	14.72	2,887
1982	80,975.76	60,133	72,911	8,065	13.69	589
1983	42,059.45	30,766	37,304	4,756	14.13	337
1984	46,511.61	33,488	40,604	5,908	14.58	405
1985	72,222.02	51,140	62,007	10,215	15.05	679
1986	43,855.97	30,515	36,999	6,857	15.52	442
1987	107,897.65	73,705	89,367	18,531	16.01	1,157
1988	160,625.82	107,619	130,487	30,138	16.50	1,827
1989	30,425.01	19,974	24,218	6,207	17.00	365
1990	108,749.56	69,882	84,731	24,018	17.52	1,371
1991	127,229.75	79,938	96,924	30,305	18.04	1,680
1992	44,347.42	27,212	32,994	11,353	18.58	611
1993	29,918.28	17,906	21,711	8,207	19.12	429
1994	29,674.28	17,300	20,976	8,698	19.67	442
1995	34,913.41	19,799	24,006	10,907	20.23	539
1996	42,589.04	23,458	28,443	14,146	20.80	680
1997	147,679.42	78,876	95,637	52,043	21.37	2,435
1998	59,434.64	30,728	37,257	22,177	21.95	1,010
1999	107,844.18	53,868	65,315	42,530	22.55	1,886
2000	88,357.27	42,747	51,830	36,527	22.94	1,592
2001	82,991.73	38,624	46,831	36,160	23.55	1,535
2002	24,753.36	11,055	13,404	11,349	24.17	470
2003	6,572.47	2,821	3,420	3,152	24.60	128
2004	11,171.29	4,575	5,547	5,624	25.24	223
2005	8,155.02	3,176	3,851	4,304	25.87	166
2006	8,567.60	3,173	3,847	4,720	26.34	179
2007	26,075.02	9,111	11,047	15,028	27.00	557
2008	31,803.84	10,476	12,702	19,102	27.48	695
2009	68,220.04	21,066	25,542	42,678	27.98	1,525
2010	60,218.85	17,313	20,992	39,227	28.50	1,376
2011	489,447.99	129,997	157,621	331,827	29.03	11,430
2012	154,849.37	37,659	45,661	109,188	29.56	3,694
2013	5,908.18	1,306	1,584	4,325	29.96	144
2014	69,835.34	13,772	16,698	53,137	30.52	1,741

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2015	3,012,389.09	522,951	634,075	2,378,314	30.95	76,844
2016	2,481,717.48	371,265	450,156	2,031,561	31.26	64,989
2017	56,121.74	6,993	8,479	47,643	31.60	1,508
	11,086,635.15	4,422,982	5,356,167	5,730,468		205,193
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1940	90.00	89	90			
1942	90.00	88	90			
1943	132.66	129	133			
1944	519.95	502	520			
1945	66.33	64	66			
1946	197.92	189	198			
1947	210.99	200	211			
1948	189.93	179	190			
1949	87.26	81	87			
1950	87.44	81	87			
1951	87.28	80	87			
1953	1,265.02	1,149	1,248	17	4.14	4
1955	1,296.62	1,161	1,261	35	4.72	7
1956	1,460.37	1,298	1,410	50	5.01	10
1957	7,995.25	7,054	7,664	332	5.30	63
1958	2,885.06	2,526	2,744	141	5.60	25
1959	2,623.82	2,280	2,477	147	5.90	25
1960	13,164.96	11,351	12,332	833	6.20	134
1961	21,807.35	18,652	20,264	1,543	6.51	237
1962	5,144.51	4,365	4,742	402	6.82	59
1963	11,141.18	9,373	10,183	958	7.14	134
1964	27,223.97	22,705	24,667	2,557	7.47	342
1965	25,450.83	21,034	22,852	2,599	7.81	333
1966	44,735.37	36,633	39,799	4,936	8.15	606
1967	40,165.22	32,578	35,394	4,772	8.50	561
1968	46,527.03	37,356	40,585	5,943	8.87	670
1969	40,719.90	32,359	35,156	5,564	9.24	602
1970	46,369.74	36,447	39,597	6,773	9.63	703
1971	37,753.88	29,339	31,875	5,879	10.03	586
1972	16,346.27	12,554	13,639	2,707	10.44	259
1973	17,281.90	13,111	14,244	3,038	10.86	280

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

CPG
SURVIVOR CURVE.. IOWA 45-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1974	15,500.00	11,608	12,611	2,889	11.30	256
1975	23,356.27	17,258	18,750	4,607	11.75	392
1976	7,679.24	5,596	6,080	1,600	12.21	131
1977	8,292.18	5,954	6,469	1,824	12.69	144
1978	4,682.18	3,311	3,597	1,085	13.18	82
1979	8,792.04	6,119	6,648	2,144	13.68	157
1980	17,159.04	11,748	12,763	4,396	14.19	310
1981	98,862.58	66,524	72,273	26,589	14.72	1,806
1982	107,317.69	79,694	86,582	20,736	13.69	1,515
1983	82,054.88	60,023	65,211	16,844	14.13	1,192
1984	56,055.83	40,360	43,848	12,208	14.58	837
1985	108,966.47	77,159	83,828	25,139	15.05	1,670
1986	78,897.92	54,897	59,642	19,256	15.52	1,241
1987	101,101.12	69,062	75,031	26,070	16.01	1,628
1988	89,032.58	59,652	64,807	24,225	16.50	1,468
1989	201,578.11	132,336	143,773	57,805	17.00	3,400
1990	181,749.75	116,792	126,886	54,864	17.52	3,132
1991	168,687.80	105,987	115,147	53,541	18.04	2,968
1992	259,022.46	158,936	172,672	86,350	18.58	4,647
1993	307,081.30	183,788	199,672	107,409	19.12	5,618
1994	257,960.73	150,391	163,389	94,572	19.67	4,808
1995	299,469.26	169,829	184,507	114,963	20.23	5,683
1996	383,632.67	211,305	229,567	154,066	20.80	7,407
1997	265,781.91	141,954	154,222	111,559	21.37	5,220
1998	699,360.80	361,570	392,819	306,542	21.95	13,965
1999	743,037.99	371,147	403,224	339,814	22.55	15,069
2000	582,884.63	282,000	306,372	276,513	22.94	12,054
2001	498,094.90	231,813	251,848	246,247	23.55	10,456
2002	223,078.26	99,627	108,237	114,841	24.17	4,751
2003	700,236.52	300,542	326,516	373,720	24.60	15,192
2004	1,411,277.60	577,918	627,865	783,413	25.24	31,039
2005	492,523.31	191,789	208,364	284,159	25.87	10,984
2006	776,322.51	287,550	312,402	463,921	26.34	17,613
2007	643,709.12	224,912	244,350	399,359	27.00	14,791
2008	820,138.66	270,154	293,502	526,636	27.48	19,164
2009	486,920.76	150,361	163,356	323,565	27.98	11,564
2010	543,937.56	156,382	169,897	374,040	28.50	13,124
2011	987,719.26	262,338	285,011	702,709	29.03	24,206
2012	353,222.86	85,904	93,328	259,895	29.56	8,792
2013	398,558.63	88,081	95,693	302,865	29.96	10,109
2014	361,466.55	71,281	77,441	284,025	30.52	9,306
2015	393,127.17	68,247	74,145	318,982	30.95	10,306

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 385 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
2016	446,979.04	66,868	72,647	374,332	31.26	11,975
2017	844,671.07	105,246	114,342	730,329	31.60	23,112
2018	1,108,263.63	109,718	119,200	989,063	31.84	31,064
2019	573,973.60	41,900	45,521	528,452	31.75	16,644
2020	121,553.14	5,543	6,022	115,531	31.39	3,681
2021	35,273.65	586	637	34,637	29.62	1,169
	17,792,163.24	6,686,767	7,264,606	10,527,557		401,482
	39,907,546.49	14,585,215	16,636,654	23,270,892		862,083

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.0 2.16

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.0 OTHER PROPERTY ON CUSTOMERS PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 46-S1						
NET SALVAGE PERCENT.. 0						
1966	1,968.69	1,495	4,289-	6,258	11.07	565
1967	207.34	156	448-	655	11.44	57
1968	820.82	610	1,750-	2,571	11.81	218
1969	4,348.68	3,196	9,169-	13,517	12.19	1,109
1970	585.40	425	1,219-	1,805	12.57	144
1971	1,925.29	1,383	3,968-	5,893	12.96	455
1972	16,780.77	11,911	34,170-	50,951	13.35	3,817
2004	19,260.94	8,055	23,108-	42,369	24.34	1,741
2005	22,925.98	9,115	26,149-	49,075	25.00	1,963
	68,823.91	36,346	104,269-	173,093		10,069

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.2 14.63

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1929	141.00	141	141			
1955	2,275.45	2,037	2,275			
1956	989.22	879	989			
1957	545.83	482	546			
1958	236.59	207	237			
1959	739.15	642	735	4	5.90	1
1960	6,231.82	5,373	6,150	82	6.20	13
1961	5,465.73	4,675	5,351	115	6.51	18
1962	1,776.66	1,507	1,725	52	6.82	8
1963	1,519.13	1,278	1,463	56	7.14	8
1964	1,895.48	1,581	1,810	86	7.47	12
1965	611.14	505	578	33	7.81	4
1966	1,500.19	1,228	1,406	95	8.15	12
1967	7,810.50	6,335	7,251	559	8.50	66
1968	5,156.86	4,140	4,739	418	8.87	47
1969	2,743.23	2,180	2,495	248	9.24	27
1970	1,104.82	868	994	111	9.63	12
1971	31,924.90	24,809	28,396	3,528	10.03	352
1972	2,029.09	1,558	1,783	246	10.44	24
1973	5,741.28	4,356	4,986	755	10.86	70
1974	677.56	507	580	97	11.30	9
1975	501.75	371	425	77	11.75	7
1976	3,733.18	2,720	3,113	620	12.21	51
1977	1,421.54	1,021	1,169	253	12.69	20
1978	182.88	129	148	35	13.18	3
1979	5,235.99	3,644	4,171	1,065	13.68	78
1980	17,091.10	11,702	13,394	3,697	14.19	261
1981	121,509.06	81,762	93,585	27,924	14.72	1,897
1982	95,200.74	70,696	80,919	14,282	13.69	1,043
1983	6,768.10	4,951	5,667	1,101	14.13	78
1984	6,649.28	4,787	5,479	1,170	14.58	80
1985	25,257.56	17,885	20,471	4,786	15.05	318
1986	23,743.92	16,521	18,910	4,834	15.52	311
1987	25,830.88	17,645	20,197	5,634	16.01	352
1988	26,270.40	17,601	20,146	6,124	16.50	371
1989	52,802.47	34,665	39,678	13,125	17.00	772
1990	55,497.04	35,662	40,819	14,678	17.52	838
1991	30,826.21	19,368	22,169	8,658	18.04	480
1992	56,752.96	34,824	39,860	16,893	18.58	909
1993	45,455.69	27,205	31,139	14,317	19.12	749
1994	30,338.27	17,687	20,245	10,094	19.67	513
1995	22,678.63	12,861	14,721	7,958	20.23	393

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.1 OTHER PROPERTY ON CUSTOMERS PREMISES - FARM TAPS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 45-R2						
NET SALVAGE PERCENT.. 0						
1996	22,335.06	12,302	14,081	8,254	20.80	397
1997	8,544.26	4,563	5,223	3,321	21.37	155
1998	8,784.27	4,541	5,198	3,587	21.95	163
1999	13,041.26	6,514	7,456	5,585	22.55	248
2000	2,551.99	1,235	1,414	1,138	22.94	50
2004	347.18	142	163	185	25.24	7
2005	3,317.00	1,292	1,479	1,838	25.87	71
2006	3,670.43	1,360	1,557	2,114	26.34	80
2010	54.74	16	18	36	28.50	1
2012	115,202.00	28,017	32,068	83,134	29.56	2,812
2013	22,348.33	4,939	5,653	16,695	29.96	557
2014	10,178.04	2,007	2,297	7,881	30.52	258
2015	499.19	87	100	400	30.95	13
2017	320.08	40	46	274	31.60	9
2018	5,899.53	584	668	5,231	31.84	164
2019	1,261.22	92	105	1,156	31.75	36
	953,217.86	566,726	648,577	304,640		15,228

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.0   1.60

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 386.2 OTHER PROPERTY ON CUSTOMERS PREMISES - GAS LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. 0						
1989	290.57	271	291			
1990	10,556.06	9,776	10,556			
1991	4,510.10	4,127	4,510			
1992	3,050.56	2,763	3,051			
1993	5,858.48	5,226	5,858			
1994	335.37	295	335			
1997	104.02	87	119	15-		
	24,705.16	22,545	24,720	15-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1919	265.57	266	266			
1922	142.27	142	142			
1924	8,840.88	8,841	8,841			
1947	455.80	456	456			
1949	22,186.47	22,186	22,186			
1950	8,371.36	8,371	8,371			
1951	1,368.79	1,369	1,369			
1952	1,125.65	1,126	1,126			
1953	30,125.92	30,126	30,126			
1954	5,517.65	5,518	5,518			
1955	601.79	602	602			
1956	8,337.58	8,338	8,338			
1957	1,905.18	1,897	1,905			
1958	651.12	644	651			
1959	15,785.61	15,497	15,786			
1960	2,005.39	1,954	2,005			
1961	1,960.14	1,895	1,960			
1962	288.11	276	288			
1963	1,039.65	989	1,040			
1964	5,769.25	5,441	5,769			
1965	1,751.72	1,640	1,752			
1966	3,912.12	3,636	3,912			
1967	4,863.78	4,489	4,864			
1968	8,062.42	7,390	8,062			
1969	1,581.42	1,440	1,581			
1970	2,285.43	2,066	2,285			
1971	10,974.98	9,852	10,975			
1972	4,046.99	3,606	4,047			
1974	1,652.12	1,451	1,652			
1975	8,480.27	7,385	8,480			
1976	7,949.17	6,866	7,949			
1977	2,458.86	2,105	2,459			
1978	1,265.56	1,074	1,266			
1979	752.79	633	753			
1980	1,718.37	1,429	1,705	13	5.89	2
1981	10,162.67	8,360	9,976	187	6.21	30
1982	12,027.61	10,404	12,028			
1983	1,755.64	1,507	1,756			
1984	30,831.09	26,129	30,831			
1985	13,068.42	10,971	13,068			
1986	19,569.87	16,188	19,330	240	7.42	32
1987	23,586.65	19,204	22,932	655	7.87	83

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1988	13,276.05	10,629	12,692	584	8.34	70
1989	15,968.66	12,612	15,060	909	8.65	105
1990	33,323.13	25,822	30,834	2,489	9.15	272
1991	26,014.16	19,755	23,589	2,425	9.66	251
1992	15,045.39	11,185	13,356	1,689	10.18	166
1993	23,968.53	17,420	20,801	3,167	10.71	296
1994	51,100.60	36,394	43,458	7,643	11.11	688
1995	69,990.02	48,594	58,026	11,964	11.67	1,025
1996	45,414.72	30,691	36,648	8,767	12.23	717
1997	84,495.34	55,480	66,249	18,247	12.81	1,424
1998	75,399.07	48,014	57,334	18,066	13.40	1,348
1999	119,656.29	73,768	88,086	31,570	14.00	2,255
2000	199,968.82	119,101	142,219	57,750	14.60	3,955
2001	116,038.59	66,606	79,534	36,504	15.21	2,400
2002	42,457.03	23,428	27,975	14,482	15.84	914
2003	222,013.40	117,467	140,267	81,746	16.47	4,963
2004	109,705.10	55,489	66,259	43,446	17.10	2,541
2005	70,405.76	33,921	40,505	29,901	17.75	1,685
2006	85,043.37	38,882	46,429	38,614	18.40	2,099
2007	37,304.93	16,119	19,248	18,057	19.06	947
2008	97,908.80	39,917	47,665	50,244	19.61	2,562
2009	42,499.78	16,201	19,346	23,154	20.29	1,141
2011	14,980.73	4,893	5,843	9,138	21.65	422
2013	30,446.98	8,230	9,827	20,620	22.95	898
2018	12,429.20	1,479	1,766	10,663	25.91	412
2019	31,358.25	2,722	3,250	28,108	26.32	1,068
2020	191,812.76	10,243	12,231	179,582	26.59	6,754
	2,167,527.59	1,208,821	1,416,906	750,622		41,525
PNG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1962	460.81	442	461			
1976	21,500.00	18,570	21,500			
1984	1,544.96	1,309	1,545			
1987	5,496.89	4,476	5,497			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1988	2,425.60	1,942	2,426			
1997	821.60	539	742	80	12.81	6
2008	85,066.24	34,682	47,741	37,325	19.61	1,903
	117,316.10	61,960	79,912	37,404		1,909
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1915	0.25		0			
1920	46.40	46	46			
1921	65.00	65	65			
1925	288.57	289	289			
1927	8.25	8	8			
1928	265.80	266	266			
1929	32.00	32	32			
1930	401.84	402	402			
1931	576.33	576	576			
1932	862.24	862	862			
1933	179.53	180	180			
1936	339.96	340	340			
1937	180.10	180	180			
1938	702.11	702	702			
1939	70.20	70	70			
1940	114.20	114	114			
1942	93.19	93	93			
1947	107.86	108	108			
1948	228.20	228	228			
1951	115.54	116	116			
1952	399.62	400	400			
1954	526.32	526	526			
1955	866.71	867	867			
1956	3,485.13	3,485	3,485			
1957	166.98	166	167			
1958	807.41	799	807			
1959	3,980.48	3,908	3,980			
1960	3,557.12	3,466	3,557			
1961	940.90	909	941			
1962	2,160.12	2,071	2,160			
1963	2,440.64	2,321	2,441			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1964	1,463.53	1,380	1,464			
1965	852.14	798	852			
1966	4,391.44	4,082	4,391			
1967	7,725.03	7,129	7,725			
1968	9,375.01	8,593	9,375			
1969	1,802.13	1,640	1,802			
1970	4,312.49	3,898	4,312			
1971	727.19	653	727			
1972	12,970.95	11,559	12,922	49	3.81	13
1973	4,161.73	3,681	4,115	47	4.04	12
1974	5,521.13	4,848	5,420	101	4.27	24
1975	4,072.92	3,547	3,965	108	4.52	24
1976	1,691.94	1,461	1,633	59	4.77	12
1977	2,859.26	2,448	2,737	123	5.03	24
1978	9,079.27	7,704	8,613	467	5.30	88
1979	8,076.46	6,789	7,590	487	5.58	87
1980	16,025.59	13,329	14,901	1,125	5.89	191
1981	16,463.34	13,542	15,139	1,324	6.21	213
1982	18,913.59	16,360	18,289	624	6.16	101
1983	17,303.36	14,857	16,609	694	6.34	109
1984	24,489.09	20,755	23,203	1,286	6.75	191
1985	30,607.35	25,695	28,725	1,882	6.98	270
1986	47,810.95	39,549	44,213	3,598	7.42	485
1987	41,095.26	33,460	37,406	3,689	7.87	469
1988	31,108.85	24,906	27,843	3,266	8.34	392
1989	67,276.33	53,135	59,401	7,875	8.65	910
1990	73,855.80	57,231	63,980	9,875	9.15	1,079
1991	72,040.64	54,708	61,160	10,881	9.66	1,126
1992	46,648.02	34,678	38,768	7,880	10.18	774
1993	72,629.85	52,787	59,012	13,618	10.71	1,272
1994	50,628.58	36,058	40,310	10,318	11.11	929
1995	79,302.27	55,060	61,553	17,749	11.67	1,521
1996	207,257.72	140,065	156,583	50,675	12.23	4,143
1997	83,557.81	54,864	61,334	22,224	12.81	1,735
1998	20,844.66	13,274	14,839	6,005	13.40	448
1999	283,838.00	174,986	195,622	88,216	14.00	6,301
2000	62,321.83	37,119	41,497	20,825	14.60	1,426
2001	24,248.93	13,919	15,560	8,688	15.21	571
2007	20,518.49	8,866	9,912	10,607	19.06	557
2011	4,783.98	1,562	1,746	3,038	21.65	140
2014	897.06	217	243	654	23.56	28
2016	7,240.43	1,314	1,469	5,771	24.80	233

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387 OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
2017	323,394.81	48,606	54,338	269,057	25.44	10,576
2018	165,355.70	19,677	21,998	143,358	25.91	5,533
2019	186,196.01	16,162	18,068	168,128	26.32	6,388
2020	386,652.62	20,647	23,082	363,571	26.59	13,673
	2,586,398.54	1,191,193	1,328,457	1,257,941		62,068
	4,871,242.23	2,461,974	2,825,275	2,045,967		105,502

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.4 2.17

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 387.1 OTHER EQUIPMENT - GRAPHIC DATA BASE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1980	53,900.00	53,900	53,900			
1981	184,018.30	184,018	184,018			
1982	328,563.00	328,563	328,563			
1983	92,573.18	92,573	92,573			
1984	103,914.03	103,914	103,914			
1985	109,975.52	109,976	109,976			
1986	113,888.51	113,889	113,889			
1987	112,021.79	112,022	112,022			
1988	167,324.21	167,324	167,324			
1989	77,363.35	77,363	77,363			
1990	11,534.69	11,535	11,535			
1991	1,588.30	1,588	1,588			
1992	3,540.35	3,540	3,540			
1993	514.88	515	515			
1995	4,074.64	4,075	4,075			
1998	10,727.14	10,084	10,389	339	1.50	226
2001	13,978.74	11,463	11,809	2,169	4.50	482
2002	7,564.41	5,900	6,078	1,486	5.50	270
2003	93,599.07	69,263	71,355	22,244	6.50	3,422
	1,490,664.11	1,461,505	1,464,426	26,238		4,400

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.0 0.30

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

UGI-GAS - LANCASTER SERVICE BUILDING
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5
PROBABLE RETIREMENT YEAR.. 6-2026
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1876	10,334.49	9,898	10,334			
1905	1,382.43	1,310	1,382			
1906	292.55	277	293			
1907	1,480.00	1,402	1,480			
1909	419.56	397	420			
1910	231.57	219	232			
1911	21.85	21	22			
1912	1,782.05	1,685	1,782			
1914	166.16	157	166			
1915	20.13	19	20			
1918	7,489.42	7,070	7,489			
1920	2,849.28	2,688	2,849			
1921	435.07	410	435			
1922	6,291.36	5,931	6,291			
1923	1,971.44	1,858	1,971			
1924	4,604.09	4,337	4,604			
1926	3,813.02	3,589	3,813			
1931	32,017.60	30,077	32,018			
1938	400.93	375	401			
1943	284.29	265	284			
1944	230.75	215	231			
1945	237.24	221	237			
1949	486.95	453	487			
1950	50,769.67	47,154	50,770			
1951	16,250.78	15,083	16,251			
1952	20,545.14	19,052	20,545			
1953	22,260.06	20,626	22,260			
1954	302,640.23	280,160	302,640			
1955	1,162.29	1,075	1,162			
1956	1,010.54	934	1,010			
1957	3,926.06	3,624	3,920	6	4.60	1
1958	1,997.30	1,842	1,992	5	4.61	1
1959	2,678.45	2,468	2,669	9	4.61	2
1960	5,791.48	5,330	5,765	27	4.61	6
1961	18,138.80	16,675	18,035	104	4.62	23
1962	12,971.47	11,912	12,883	88	4.62	19
1963	9,060.40	8,309	8,987	74	4.63	16
1964	11,494.93	10,530	11,389	106	4.63	23
1965	5,910.61	5,408	5,849	62	4.63	13
1966	358.24	327	354	5	4.64	1
1967	496.96	453	490	7	4.64	2

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - LANCASTER SERVICE BUILDING INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2026 NET SALVAGE PERCENT.. 0						
1968	1,817.74	1,656	1,791	27	4.64	6
1969	7,616.15	6,929	7,494	122	4.65	26
1970	3,024.29	2,747	2,971	53	4.65	11
1971	1,477.38	1,340	1,449	28	4.65	6
1972	596.71	540	584	13	4.66	3
1973	3,204.98	2,897	3,133	72	4.66	15
1978	1,708.01	1,529	1,654	54	4.67	12
1980	6,221.53	5,542	5,994	228	4.68	49
1983	15,322.42	13,686	14,802	520	4.60	113
1985	12,630.08	11,203	12,117	513	4.65	110
1988	52,754.56	46,303	50,079	2,675	4.67	573
1989	8,424.15	7,364	7,965	460	4.68	98
1990	123,521.99	107,390	116,148	7,374	4.73	1,559
1992	47,851.27	41,219	44,581	3,271	4.75	689
1994	1,725,445.56	1,475,601	1,595,946	129,500	4.66	27,790
1995	22,173.60	18,861	20,399	1,774	4.65	382
1996	2,259.68	1,907	2,063	197	4.71	42
1998	25,800.00	21,522	23,277	2,523	4.67	540
2000	8,328.00	6,840	7,398	930	4.68	199
2001	24,091.65	19,606	21,205	2,887	4.69	616
2002	46,954.16	37,817	40,901	6,053	4.71	1,285
2003	136,654.40	108,968	117,855	18,799	4.70	4,000
2004	72,983.68	57,475	62,162	10,821	4.72	2,293
2005	59,996.43	46,725	50,536	9,461	4.69	2,017
2012	74,314.34	49,701	53,754	20,560	4.70	4,374
2014	123,382.06	75,781	81,961	41,421	4.71	8,794
2015	9,379.40	5,438	5,882	3,498	4.71	743
2016	80,514.53	43,397	46,936	33,578	4.70	7,144
2018	20,625.68	8,799	9,517	11,109	4.70	2,364
2020	28,973.94	7,023	7,596	21,378	4.69	4,558
	3,312,754.01	2,759,642	2,982,363	330,391		70,518
UGI-GAS - READING SERVICE BUILDING INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2030 NET SALVAGE PERCENT.. 0						
1951	822.27	721	779	43	8.14	5
1953	24,900.89	21,758	23,514	1,387	8.17	170

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2030						
NET SALVAGE PERCENT.. 0						
1954	20,454.90	17,844	19,284	1,171	8.19	143
1955	802,717.61	699,207	755,638	47,080	8.20	5,741
1956	1,047.45	911	985	63	8.22	8
1957	10,249.83	8,896	9,614	636	8.24	77
1958	2,482.66	2,151	2,325	158	8.25	19
1959	5,630.20	4,869	5,262	368	8.27	44
1960	4,948.06	4,271	4,616	332	8.28	40
1961	539,405.64	464,741	502,249	37,157	8.29	4,482
1962	339.03	291	314	25	8.31	3
1963	277.93	238	257	21	8.32	3
1966	3,859.88	3,289	3,554	305	8.36	36
1967	2,790.92	2,373	2,565	226	8.37	27
1969	866.59	733	792	74	8.39	9
1970	8,683.00	7,325	7,916	767	8.40	91
1971	17,218.52	14,486	15,655	1,563	8.41	186
1972	3,388.32	2,842	3,071	317	8.42	38
1973	2,861.11	2,393	2,586	275	8.43	33
1974	1,212,931.09	1,011,209	1,092,820	120,111	8.44	14,231
1975	22,751.74	18,906	20,432	2,320	8.45	275
1976	53,536.37	44,336	47,914	5,622	8.46	665
1977	35,227.17	29,069	31,415	3,812	8.47	450
1978	16,095.24	13,235	14,303	1,792	8.47	212
1979	149,196.20	122,208	132,071	17,125	8.48	2,019
1980	468,802.00	382,449	413,315	55,487	8.49	6,536
1981	57,414.00	46,636	50,400	7,014	8.50	825
1982	38,599.74	31,714	34,274	4,326	8.58	504
1983	2,914.84	2,390	2,583	332	8.45	39
1984	89,751.74	73,040	78,935	10,817	8.58	1,261
1985	57,745.00	46,791	50,567	7,178	8.55	840
1986	140,082.48	112,878	121,988	18,094	8.56	2,114
1987	3,330.36	2,677	2,893	437	8.42	52
1988	2,092.34	1,668	1,803	290	8.52	34
1989	972,608.86	771,279	833,526	139,083	8.48	16,401
1990	711,529.29	560,329	605,551	105,978	8.50	12,468
1991	57,350.73	44,779	48,393	8,958	8.56	1,046
1992	352,697.17	273,622	295,705	56,992	8.52	6,689
1993	37,015.00	28,483	30,782	6,233	8.54	730
1994	357,100.74	272,039	293,994	63,106	8.60	7,338
1995	58,034.11	43,827	47,364	10,670	8.59	1,242
1996	43,356.00	32,504	35,127	8,229	8.51	967
1997	18,172.30	13,491	14,580	3,592	8.50	423

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - READING SERVICE BUILDING INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2030 NET SALVAGE PERCENT.. 0						
1998	267,045.47	195,798	211,600	55,445	8.55	6,485
1999	63,417.26	45,946	49,654	13,763	8.56	1,608
2000	1,493,655.69	1,069,457	1,155,769	337,886	8.53	39,611
2001	472,677.71	333,332	360,234	112,444	8.57	13,121
2002	173,687.14	120,574	130,305	43,382	8.59	5,050
2003	217,296.76	148,327	160,298	56,999	8.60	6,628
2004	253,079.99	170,070	183,796	69,284	8.54	8,113
2005	757,568.33	498,783	539,038	218,530	8.56	25,529
2006	211,761.65	136,205	147,198	64,564	8.60	7,507
2007	821,576.80	515,786	557,413	264,163	8.60	30,717
2008	547,767.46	335,015	362,053	185,715	8.57	21,670
2009	132,314.80	78,397	84,724	47,591	8.60	5,534
2010	92,229.97	52,820	57,083	35,147	8.58	4,096
2011	75,088.53	41,314	44,648	30,440	8.58	3,548
2012	249,484.70	131,079	141,658	107,827	8.58	12,567
2013	35,996.21	17,930	19,377	16,619	8.56	1,941
2014	444,246.90	207,241	223,967	220,280	8.58	25,674
2015	382,922.06	165,039	178,359	204,563	8.58	23,842
2016	809,233.07	316,410	341,946	467,287	8.57	54,526
2017	193,084.82	66,556	71,928	121,157	8.55	14,170
2018	1,026,883.21	298,310	322,386	704,498	8.55	82,397
2019	2,664,775.46	604,371	653,148	2,011,628	8.52	236,107
2020	67,428.28	10,134	10,952	56,476	8.48	6,660
2021	363,702.37	20,586	22,247	341,455	8.33	40,991
	18,228,203.96	10,818,378	11,691,493	6,536,711		766,608
UGI-GAS - BETHLEHEM SERVICE BUILDING INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 3-2050 NET SALVAGE PERCENT.. 0						
1951	730.20	519	561	169	21.54	8
1957	163.83	113	122	42	22.52	2
1962	40,974.62	27,398	29,609	11,365	23.25	489
1965	1,567,005.46	1,028,191	1,111,173	455,833	23.65	19,274
1966	142,946.82	93,177	100,697	42,250	23.78	1,777
1967	15,954.41	10,329	11,163	4,792	23.91	200
1968	9,460.27	6,082	6,573	2,887	24.03	120
1969	18,666.34	11,916	12,878	5,789	24.15	240

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - BETHLEHEM SERVICE BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2050						
NET SALVAGE PERCENT.. 0						
1970	12,903.20	8,176	8,836	4,067	24.27	168
1971	7,221.56	4,542	4,909	2,313	24.38	95
1975	432.10	263	284	148	24.81	6
1976	3,658.72	2,209	2,387	1,271	24.91	51
1977	2,770.44	1,657	1,791	980	25.01	39
1981	873.48	502	543	331	25.37	13
1982	6,159.03	3,795	4,101	2,058	24.60	84
1984	25,998.29	15,698	16,965	9,033	24.61	367
1987	84,605.93	49,038	52,996	31,610	25.02	1,263
1989	25,957.50	14,679	15,864	10,094	24.97	404
1990	146,946.76	81,938	88,551	58,396	24.99	2,337
1991	1,839.60	1,010	1,092	748	25.06	30
1992	58,567.66	31,615	34,167	24,401	25.15	970
1994	10,549.87	5,484	5,927	4,623	25.41	182
1996	316,288.61	158,081	170,839	145,449	25.52	5,699
1997	209,065.14	102,442	110,710	98,355	25.50	3,857
1998	101,386.46	48,605	52,528	48,859	25.52	1,915
1999	77,675.00	36,352	39,286	38,389	25.58	1,501
2000	1,473.37	672	726	747	25.67	29
2001	99,787.96	44,386	47,968	51,820	25.59	2,025
2002	62,622.22	27,109	29,297	33,325	25.55	1,304
2003	67,677.49	28,296	30,580	37,098	25.75	1,441
2004	91,646.14	37,208	40,211	51,435	25.60	2,009
2005	181,796.97	71,083	76,820	104,977	25.70	4,085
2006	25,352.02	9,548	10,319	15,033	25.65	586
2007	26,253.00	9,477	10,242	16,011	25.66	624
2008	2,114.70	728	787	1,328	25.72	52
2009	1,660.00	544	588	1,072	25.67	42
2010	11,586.09	3,585	3,874	7,712	25.67	300
2011	102,995.75	29,848	32,257	70,739	25.73	2,749
2012	74,314.34	20,050	21,668	52,646	25.71	2,048
2013	46,334.76	11,537	12,468	33,867	25.63	1,321
2014	313,407.10	70,987	76,716	236,691	25.61	9,242
2015	323,293.30	65,564	70,855	252,438	25.55	9,880
2016	640,776.43	113,802	122,987	517,790	25.46	20,337
2017	530,512.31	80,001	86,458	444,055	25.35	17,517
2018	1,495,921.82	182,802	197,555	1,298,366	25.15	51,625

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - BETHLEHEM SERVICE BUILDING INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 3-2050 NET SALVAGE PERCENT.. 0						
2019	1,390,967.74	127,274	137,546	1,253,422	24.82	50,500
2020	221,951.83	12,873	13,912	208,040	24.34	8,547
2021	307,258.62	6,545	7,073	300,185	22.97	13,069
	8,908,505.26	2,697,730	2,915,455	5,993,050		240,423
UGI-GAS - LEBANON SERVICE BUILDING INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2027 NET SALVAGE PERCENT.. 0						
1933	657.93	610	658			
1992	1,969,044.37	1,649,665	1,782,805	186,239	5.71	32,616
1993	15,226.14	12,714	13,740	1,486	5.63	264
1994	10,056.65	8,352	9,026	1,031	5.61	184
2000	1,880.00	1,487	1,607	273	5.67	48
2001	34,203.52	26,785	28,947	5,257	5.68	926
	2,031,068.61	1,699,613	1,836,783	194,286		34,038
UGI-GAS - STONE RIDGE SERVICE BUILDING INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2059 NET SALVAGE PERCENT.. 0						
2009	4,797,873.14	1,337,647	1,445,604	3,352,269	32.34	103,657
2011	174,377.96	42,845	46,303	128,075	32.24	3,973
2020	35,332.08	1,682	1,818	33,514	30.04	1,116
2021	38,715.34	681	736	37,979	27.91	1,361
	5,046,298.52	1,382,855	1,494,461	3,551,838		110,107
UGI-GAS - GAS TRAINING CENTER INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 9-2071 NET SALVAGE PERCENT.. 0						
2021	27,836,758.65	417,551	451,250	27,385,509	32.94	831,376
	27,836,758.65	417,551	451,250	27,385,509		831,376

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

UGI-GAS - OTHER STRUCTURES
SURVIVOR CURVE.. IOWA 40-R2
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1871	2,385.33	2,385	2,385			
1905	642.75	643	643			
1910	67.06	67	67			
1911	241.41	241	241			
1915	150.63	151	151			
1922	250.95	251	251			
1923	297.04	297	297			
1924	61.13	61	61			
1928	44,791.52	44,792	44,792			
1929	1,227.11	1,227	1,227			
1931	6,591.16	6,591	6,591			
1932	589.45	589	589			
1933	40.24	40	40			
1934	309.40	309	309			
1935	4,124.32	4,124	4,124			
1937	242.44	242	242			
1938	143.77	144	144			
1940	95.93	96	96			
1943	273.84	274	274			
1947	6,946.66	6,947	6,947			
1948	401.47	399	401			
1949	1,806.43	1,786	1,806			
1950	2,196.55	2,157	2,197			
1951	233.36	228	233			
1953	2,899.07	2,790	2,899			
1955	1,973.05	1,871	1,973			
1957	1,355.54	1,266	1,356			
1958	5,763.15	5,342	5,763			
1959	1,512.13	1,391	1,512			
1960	3,574.90	3,262	3,575			
1961	649.28	588	648	2	3.79	1
1962	9,412.34	8,452	9,309	103	4.08	25
1963	12,936.88	11,524	12,693	244	4.37	56
1964	3,052.55	2,696	2,969	83	4.67	18
1966	2,516.15	2,185	2,407	110	5.26	21
1967	1,274.89	1,098	1,209	66	5.56	12
1968	419.83	358	394	26	5.87	4
1970	80.61	67	74	7	6.51	1
1971	1,544.75	1,281	1,411	134	6.84	20
1972	1,090.13	894	985	105	7.19	15

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS - OTHER STRUCTURES SURVIVOR CURVE.. IOWA 40-R2 NET SALVAGE PERCENT.. 0						
1975	164.27	130	143	21	8.28	3
1976	3,452.10	2,704	2,978	474	8.67	55
1977	7,165.00	5,540	6,102	1,063	9.07	117
1978	6,220.72	4,745	5,226	995	9.49	105
1979	3,107.33	2,337	2,574	533	9.92	54
1980	5,058.60	3,747	4,127	932	10.37	90
1983	369.74	289	318	51	10.76	5
1986	5,526.05	4,139	4,559	967	11.90	81
1988	338.67	244	269	70	13.01	5
1989	11,535.55	8,173	9,002	2,534	13.37	190
1991	3,137.18	2,134	2,350	787	14.34	55
1994	17,386.12	10,997	12,112	5,274	15.98	330
1995	5,075.97	3,134	3,452	1,624	16.42	99
1997	38,896.24	22,680	24,980	13,916	17.52	794
1998	20,290.00	11,492	12,657	7,633	17.99	424
1999	9,250.00	5,058	5,571	3,679	18.65	197
2000	4,627.46	2,447	2,695	1,932	19.15	101
2001	14,287.96	7,293	8,033	6,255	19.66	318
2002	39,331.76	19,328	21,288	18,044	20.18	894
2003	18,220.00	8,596	9,468	8,752	20.71	423
2005	53,233.48	22,837	25,153	28,081	21.96	1,279
2007	2,169.82	837	922	1,248	23.09	54
2011	148,951.37	43,792	48,232	100,719	25.21	3,995
2012	1,935.54	522	575	1,361	25.71	53
2013	5,265.73	1,289	1,420	3,846	26.22	147
2014	34,471.72	7,549	8,314	26,157	26.75	978
2015	20,002.66	3,861	4,253	15,750	27.17	580
2016	52,555.80	8,730	9,615	42,941	27.61	1,555
2017	7,563.46	1,048	1,154	6,409	27.97	229
2018	262,071.27	28,985	31,924	230,147	28.15	8,176
2019	145,916.08	11,848	13,049	132,867	28.27	4,700
2020	106,559.48	5,413	5,962	100,598	28.00	3,593
2021	33,284.92	619	682	32,603	26.45	1,233
	1,211,587.25	381,643	412,444	799,143		31,085

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

PNG - EMPIRE YARD - MAJOR STRUCTURES
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5
PROBABLE RETIREMENT YEAR.. 12-2047
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1960	100,930.51	69,813	76,917	24,013	21.60	1,112
1961	86,871.16	59,761	65,842	21,029	21.72	968
1962	141,136.69	96,554	106,380	34,757	21.84	1,591
1963	9,480.45	6,448	7,104	2,376	21.96	108
1964	3,689.12	2,494	2,748	941	22.08	43
1965	479.00	322	355	124	22.19	6
1966	297.39	199	219	78	22.30	3
1967	860.37	571	629	231	22.40	10
1968	3,570.31	2,355	2,595	976	22.51	43
1969	661.27	433	477	184	22.61	8
1970	2,325.05	1,513	1,667	658	22.71	29
1971	74,835.43	48,354	53,275	21,561	22.81	945
1972	5,279.41	3,387	3,732	1,548	22.90	68
1973	5,863.34	3,734	4,114	1,749	22.99	76
1974	1,077.54	681	750	327	23.08	14
1975	20,112.15	12,607	13,890	6,222	23.17	269
1976	98,397.02	61,186	67,412	30,985	23.25	1,333
1977	262,518.62	161,869	178,341	84,177	23.33	3,608
1978	14,862.88	9,085	10,010	4,853	23.41	207
1979	31,316.64	18,968	20,898	10,418	23.49	444
1980	50,253.77	30,147	33,215	17,039	23.57	723
1981	48,963.34	29,092	32,053	16,911	23.64	715
1982	16,098.09	10,174	11,209	4,889	23.00	213
1983	15,919.21	9,991	11,008	4,911	22.85	215
1984	47,604.50	29,458	32,456	15,149	23.10	656
1985	68,749.88	42,157	46,447	22,303	23.02	969
1986	220,372.23	132,995	146,529	73,843	23.32	3,167
1987	95,726.84	57,130	62,944	32,783	23.31	1,406
1988	78,940.78	46,543	51,279	27,661	23.32	1,186
1989	133,833.58	77,864	85,788	48,046	23.36	2,057
1990	1,474.46	845	931	543	23.45	23
1991	12,756.63	7,197	7,929	4,827	23.56	205
1992	108,291.24	60,383	66,528	41,763	23.41	1,784
1993	238,990.24	130,775	144,083	94,907	23.58	4,025
1994	9,228.65	4,974	5,480	3,748	23.52	159
1995	133,112.29	70,203	77,347	55,765	23.75	2,348
1996	77,622.54	40,177	44,266	33,357	23.76	1,404
1997	4,624,824.64	2,345,711	2,584,419	2,040,406	23.81	85,695
1998	280,621.46	139,132	153,291	127,331	23.90	5,328
1999	84,872.92	41,248	45,446	39,427	23.80	1,657
2000	89,743.66	42,646	46,986	42,758	23.75	1,800

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MAJOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2047						
NET SALVAGE PERCENT.. 0						
2001	725,398.24	334,554	368,599	356,799	23.95	14,898
2002	42,268.05	18,957	20,886	21,382	23.98	892
2003	180,782.36	78,930	86,962	93,820	23.87	3,930
2004	146,160.24	61,650	67,924	78,237	23.99	3,261
2005	167,022.30	68,078	75,006	92,016	23.98	3,837
2006	140,015.92	54,914	60,502	79,514	24.02	3,310
2007	877,150.17	330,686	364,338	512,812	23.96	21,403
2008	79,300.50	28,580	31,488	47,812	23.96	1,995
2009	54,131.55	18,540	20,427	33,705	24.00	1,404
2010	196,247.48	63,643	70,120	126,128	23.96	5,264
2011	314,990.40	95,915	105,676	209,315	23.98	8,729
2012	49,422.81	14,036	15,464	33,958	23.95	1,418
2013	122,684.15	32,217	35,496	87,189	23.86	3,654
2014	163,988.66	39,226	43,218	120,771	23.85	5,064
2015	94,908.17	20,358	22,430	72,478	23.80	3,045
2016	608,702.23	114,497	126,149	482,554	23.74	20,327
2017	58,203.25	9,324	10,273	47,930	23.59	2,032
2018	71,772.28	9,316	10,264	61,508	23.46	2,622
2019	6,739.12	655	722	6,017	23.21	259
2020	45,676.11	2,823	3,110	42,566	22.77	1,869
2021	221,491.88	5,006	5,515	215,976	21.58	10,008
	11,669,621.17	5,311,081	5,851,555	5,818,066		245,841
PNG - EMPIRE YARD - MINOR STRUCTURES						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2022						
NET SALVAGE PERCENT.. 0						
1960	27,374.98	27,126	27,375			
1961	2,250.14	2,229	2,250			
1962	11,395.40	11,289	11,395			
1964	212.41	210	212			
1965	479.69	475	480			
1972	4,846.95	4,794	4,847			
1973	59,338.04	58,680	59,338			
1976	674.99	667	675			
1977	9,114.69	9,006	9,115			
1978	24,124.85	23,831	24,125			
1979	540.75	534	541			

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - EMPIRE YARD - MINOR STRUCTURES INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 3-2022 NET SALVAGE PERCENT.. 0						
1980	8,726.53	8,615	8,727			
1981	52,430.77	51,749	52,431			
1982	22,292.87	22,014	22,293			
1984	11,417.15	11,260	11,417			
1986	31,130.64	30,723	31,131			
1987	11,362.33	11,211	11,362			
1988	15,773.37	15,535	15,773			
1989	8,654.63	8,523	8,655			
1990	94,337.02	93,016	94,337			
1992	6,049.58	5,943	6,050			
1993	1,598.34	1,571	1,598			
1994	38,859.45	38,152	38,859			
1995	4,586.75	4,497	4,587			
1996	1,532.27	1,504	1,532			
1997	1,129.92	1,107	1,130			
1998	3,483.10	3,413	3,483			
2001	6,551.41	6,393	6,551			
2002	8,685.69	8,469	8,686			
2003	26,975.97	26,250	26,976			
2004	262,708.52	255,615	262,709			
2005	28,203.02	27,363	28,203			
2008	29,302.79	28,245	29,303			
2010	189,349.18	181,397	189,349			
2011	217,404.63	207,491	217,405			
2014	19,697.18	18,466	19,697			
2016	36,430.01	33,399	36,430			
2017	42,967.09	38,670	42,967			
2018	58,528.05	51,212	58,528			
2019	838,990.00	699,298	838,990			
	2,219,511.15	2,029,942	2,219,511			
PNG - ARCHBALD INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 12-2052 NET SALVAGE PERCENT.. 0						
2001	6,628.41	2,826	3,126	3,502	27.58	127
2002	3,783,335.80	1,564,031	1,730,227	2,053,108	27.67	74,200
2003	87,794.37	35,083	38,811	48,983	27.80	1,762

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - ARCHBALD						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2052						
NET SALVAGE PERCENT.. 0						
2004	116,222.01	44,955	49,732	66,490	27.75	2,396
2005	21,321.99	7,951	8,796	12,526	27.75	451
2006	70,501.63	25,240	27,922	42,580	27.79	1,532
2007	23,909.23	8,182	9,051	14,858	27.87	533
2008	36,082.96	11,788	13,041	23,042	27.82	828
2009	2,440.34	757	837	1,603	27.82	58
2010	44,187.56	12,956	14,333	29,855	27.72	1,077
2011	22,823.04	6,254	6,919	15,904	27.82	572
2012	5,700.89	1,457	1,612	4,089	27.67	148
2013	10,921.02	2,562	2,834	8,087	27.73	292
2014	82,583.84	17,656	19,532	63,052	27.59	2,285
2015	2,300.95	440	487	1,814	27.51	66
2016	41,558.96	6,949	7,687	33,872	27.39	1,237
2017	11,135.61	1,579	1,747	9,389	27.24	345
2018	114,113.01	13,055	14,442	99,671	27.08	3,681
2019	936,945.86	80,109	88,622	848,324	26.74	31,725
2020	15,681.92	852	943	14,739	26.12	564
2021	84,737.22	1,695	1,875	82,862	24.56	3,374
	5,520,926.62	1,846,377	2,042,576	3,478,351		127,253
PNG - BLOOMSBURG						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2059						
NET SALVAGE PERCENT.. 0						
1907	12.46	10	11	1	12.90	
1909	57.76	48	53	5	13.46	
1910	136.78	113	125	12	13.75	1
1912	15.65	13	14	1	14.31	
1915	2,677.72	2,170	2,401	277	15.17	18
1930	25,467.58	19,212	21,254	4,214	19.53	216
1933	41.56	31	34	7	20.41	
1934	68.83	51	56	12	20.70	1
1944	71.26	50	55	16	23.61	1
1968	646.66	378	418	228	29.76	8
1974	842.24	465	514	328	30.97	11
1976	103,603.50	55,980	61,929	41,675	31.34	1,330
1977	20,984.75	11,212	12,403	8,581	31.52	272
1978	83.39	44	49	35	31.69	1

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ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - BLOOMSBURG						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2059						
NET SALVAGE PERCENT.. 0						
1980	1,544.84	796	881	664	32.03	21
1981	984.45	501	554	430	32.19	13
1983	3,281.25	1,832	2,027	1,255	30.47	41
1984	4,173.75	2,301	2,546	1,628	30.53	53
1987	1,513.65	794	878	635	31.29	20
1988	13,483.87	7,001	7,745	5,739	31.02	185
1991	1,061.00	521	576	485	31.61	15
1996	7,009.14	3,110	3,440	3,569	31.97	112
1998	26,471.23	11,197	12,387	14,084	32.06	439
2000	16,127.75	6,449	7,134	8,993	32.26	279
2001	5,503.51	2,132	2,359	3,145	32.41	97
2003	14,245.64	5,165	5,714	8,532	32.52	262
2007	20,621.98	6,339	7,013	13,609	32.67	417
2008	5,631.08	1,650	1,825	3,806	32.58	117
2010	19,035.29	4,968	5,496	13,539	32.56	416
2011	187,198.19	45,601	50,447	136,752	32.60	4,195
2014	780,161.32	146,826	162,428	617,733	32.34	19,101
2015	32,204.52	5,401	5,975	26,230	32.26	813
2016	12,899.16	1,887	2,088	10,812	32.09	337
2018	55,602.72	5,549	6,139	49,464	31.59	1,566
2019	14,930.36	1,108	1,226	13,705	31.17	440
	1,378,394.84	350,905	388,193	990,202		30,798
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1971	279,616.37	231,802	256,434	23,183	6.84	3,389
1972	1,534.12	1,258	1,392	142	7.19	20
1973	1,448.41	1,175	1,300	149	7.54	20
1974	13,842.50	11,109	12,289	1,553	7.90	197
1975	146,776.04	116,393	128,761	18,015	8.28	2,176
1976	284,409.36	222,764	246,435	37,974	8.67	4,380
1978	1,790.28	1,366	1,511	279	9.49	29
1983	1,783.82	1,394	1,542	242	10.76	22
1984	8,520.87	6,582	7,281	1,239	11.04	112
1986	1,514.84	1,135	1,256	259	11.90	22
1987	65,137.00	47,863	52,949	12,188	12.45	979
1988	169,541.45	122,104	135,079	34,463	13.01	2,649

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1989	18,663.17	13,223	14,628	4,035	13.37	302
1990	3,349.53	2,321	2,568	782	13.95	56
1992	921.16	611	676	245	14.94	16
1994	8,616.93	5,450	6,029	2,588	15.98	162
1995	478.10	295	326	152	16.42	9
1996	2,301.93	1,385	1,532	770	16.87	46
1997	23,460.19	13,680	15,134	8,327	17.52	475
1998	20,910.41	11,844	13,103	7,808	17.99	434
1999	5,025.24	2,748	3,040	1,985	18.65	106
2000	411,880.07	217,843	240,991	170,889	19.15	8,924
2001	15,936.04	8,134	8,998	6,938	19.66	353
2002	132,402.81	65,063	71,977	60,426	20.18	2,994
2003	14,271.77	6,733	7,448	6,823	20.71	329
2004	40,977.09	18,431	20,390	20,588	21.41	962
2005	20,042.49	8,598	9,512	10,531	21.96	480
2007	63,327.92	24,426	27,022	36,306	23.09	1,572
2008	2,287.79	834	923	1,365	23.54	58
2009	9,297.12	3,172	3,509	5,788	24.13	240
2010	66,442.25	21,089	23,330	43,112	24.73	1,743
2011	414,026.48	121,724	134,659	279,368	25.21	11,082
2012	84,354.10	22,759	25,177	59,177	25.71	2,302
2014	114,343.64	25,041	27,702	86,642	26.75	3,239
2015	184,377.83	35,585	39,366	145,012	27.17	5,337
2016	68,563.53	11,388	12,598	55,965	27.61	2,027
2017	317,824.20	44,050	48,731	269,093	27.97	9,621
2018	370,611.45	40,990	45,346	325,266	28.15	11,555
2019	369,914.61	30,037	33,229	336,686	28.27	11,910
2020	669,594.22	34,015	37,629	631,965	28.00	22,570
2021	1,442,717.82	26,835	29,687	1,413,031	26.45	53,423
	5,872,834.95	1,583,249	1,751,487	4,121,348		166,322
CPG - STROUDSBURG DISTRICT OFFICE						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2033						
NET SALVAGE PERCENT.. 0						
1970	2,453.00	1,965	2,453			
1971	872.29	696	872			
1977	342.77	267	338	5	11.23	
1989	1,813.00	1,343	1,699	114	11.36	10

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - STROUDSBURG DISTRICT OFFICE INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2033 NET SALVAGE PERCENT.. 0						
1991	11,104.08	8,095	10,239	865	11.34	76
1993	1,829.56	1,309	1,656	174	11.34	15
1994	164,577.50	116,323	147,135	17,442	11.41	1,529
1995	8,948.74	6,261	7,919	1,029	11.38	90
1996	553.43	382	483	70	11.40	6
1997	6,824.90	4,666	5,902	923	11.34	81
1998	2,764.61	1,864	2,358	407	11.34	36
2000	60,727.10	39,691	50,205	10,522	11.39	924
2005	3,338.96	1,972	2,494	845	11.43	74
2006	4,214.76	2,430	3,074	1,141	11.38	100
2008	49,021.21	26,540	33,570	15,451	11.44	1,351
2010	2,592.10	1,300	1,644	948	11.44	83
2011	12,791.22	6,124	7,746	5,045	11.43	441
2015	136,503.33	49,605	62,745	73,759	11.39	6,476
2016	124,471.63	40,528	51,263	73,208	11.39	6,427
2017	98,527.99	27,933	35,332	63,196	11.37	5,558
2018	17,640.50	4,161	5,263	12,377	11.34	1,091
2021	55,205.36	2,412	3,051	52,154	10.94	4,767
	767,118.04	345,867	437,442	329,676		29,135
CPG - PORT ALLEGANY OPERATIONS CENTER INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2042 NET SALVAGE PERCENT.. 0						
1990	127.23	79	100	27	19.01	1
1993	758,027.04	453,679	573,799	184,228	19.12	9,635
1994	3,146.41	1,852	2,342	804	19.23	42
1995	8,657.45	5,001	6,325	2,332	19.37	120
1996	2,701.38	1,536	1,943	759	19.35	39
1997	9,933.05	5,549	7,018	2,915	19.36	151
1999	1,738.51	935	1,183	556	19.34	29
2001	420,169.40	216,219	273,467	146,702	19.34	7,585
2003	86,006.96	42,006	53,128	32,879	19.38	1,697
2004	10,670.85	5,060	6,400	4,271	19.40	220
2005	32,699.77	14,999	18,970	13,729	19.47	705
2007	34,349.48	14,695	18,586	15,764	19.40	813
2009	25,709.98	10,058	12,721	12,989	19.45	668
2010	22,825.61	8,477	10,721	12,104	19.46	622

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CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - PORT ALLEGANY OPERATIONS CENTER INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2042 NET SALVAGE PERCENT.. 0						
2011	16,891.81	5,924	7,492	9,399	19.44	483
2012	2,393.22	787	995	1,398	19.40	72
2013	4,156.41	1,265	1,600	2,556	19.43	132
2014	18,718.75	5,223	6,606	12,113	19.38	625
2015	136,614.01	34,372	43,473	93,141	19.34	4,816
2016	10,340.67	2,291	2,898	7,443	19.32	385
2018	11,932.98	1,842	2,330	9,603	19.17	501
2019	5,810.76	675	854	4,957	19.01	261
2020	32,335.00	2,396	3,030	29,305	18.74	1,564
2021	4,225.20	115	145	4,080	17.92	228
	1,660,181.93	835,035	1,056,127	604,055		31,394
CPG - POTTSVILLE METER SHOP INTERIM SURVIVOR CURVE.. IOWA 80-R1.5 PROBABLE RETIREMENT YEAR.. 6-2049 NET SALVAGE PERCENT.. 0						
1937	1,234.84	938	1,186	48	18.66	3
1961	294.42	199	252	43	22.66	2
1970	377.45	241	305	73	23.76	3
1976	1,808.65	1,103	1,395	414	24.36	17
1982	26,509.40	16,441	20,794	5,715	24.19	236
1987	357.42	210	266	92	24.32	4
1988	95.00	55	70	25	24.30	1
1989	24.29	14	18	7	24.64	
1990	2,123.00	1,190	1,505	618	24.68	25
1992	4,760.80	2,598	3,286	1,475	24.55	60
1993	2,703.40	1,448	1,831	872	24.69	35
1995	18,973.34	9,805	12,401	6,572	24.78	265
1996	4,307.22	2,185	2,764	1,544	24.75	62
1997	9,271.45	4,588	5,803	3,469	25.00	139
1998	11,191.78	5,418	6,853	4,339	25.04	173
2000	519,130.02	239,942	303,472	215,658	25.01	8,623
2001	12,387.00	5,587	7,066	5,321	24.95	213
2002	2,306.86	1,008	1,275	1,032	25.14	41
2004	6,184.42	2,543	3,216	2,968	25.06	118

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - POTTSVILLE METER SHOP						
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2049						
NET SALVAGE PERCENT.. 0						
2009	184,472.34	61,337	77,577	106,895	25.09	4,260
2014	17,931.59	4,128	5,221	12,711	25.07	507
2017	149,837.36	23,060	29,166	120,672	24.74	4,878
	976,282.05	384,038	485,720	490,562		19,665
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1911	2,631.33	2,631	2,631			
1915	4,425.79	4,426	4,426			
1922	34.95	35	35			
1929	48,718.14	48,718	48,718			
1930	5,726.24	5,726	5,726			
1931	738.76	739	739			
1932	1,329.50	1,330	1,330			
1937	459.65	460	460			
1938	798.45	798	798			
1939	66.22	66	66			
1940	505.95	506	506			
1945	20.08	20	20			
1947	1,700.00	1,700	1,700			
1949	153.57	152	154			
1950	3,419.22	3,358	3,419			
1954	114.00	109	114			
1955	3,369.90	3,196	3,370			
1959	10,313.10	9,485	10,313			
1960	27,782.48	25,352	27,782			
1961	1,594.52	1,443	1,595			
1962	1,314.41	1,180	1,314			
1963	614.41	547	614			
1964	746.64	659	747			
1965	861.27	754	861			
1966	1,553.29	1,349	1,553			
1967	104,751.07	90,191	104,751			
1968	23,858.73	20,357	23,859			
1969	4,640.61	3,922	4,641			
1970	2,008.79	1,682	2,009			
1971	2,014.32	1,670	2,014			

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YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
1972	4,281.55	3,512	4,282			
1973	2,776.85	2,253	2,777			
1974	3,268.03	2,623	3,268			
1975	12,868.29	10,205	12,868			
1977	487.18	377	482	5	9.07	1
1978	3,675.13	2,803	3,583	92	9.49	10
1979	423.97	319	408	16	9.92	2
1980	1,309.69	970	1,240	70	10.37	7
1981	4,025.99	2,936	3,754	272	10.83	25
1982	4,614.96	3,664	4,615			
1983	11,408.95	8,917	11,400	9	10.76	1
1984	500.00	386	493	7	11.04	1
1985	12,832.20	9,742	12,455	377	11.58	33
1986	1,022.46	766	979	43	11.90	4
1988	1,781.17	1,283	1,640	141	13.01	11
1989	13,848.31	9,812	12,544	1,304	13.37	98
1990	1,502.94	1,042	1,332	171	13.95	12
1991	236,214.33	160,673	205,416	30,798	14.34	2,148
1992	44,551.84	29,574	37,810	6,742	14.94	451
1993	18,016.03	11,707	14,967	3,049	15.36	199
1994	112,769.99	71,327	91,190	21,580	15.98	1,350
1995	123,184.01	76,054	97,233	25,951	16.42	1,580
1996	39,025.60	23,486	30,026	8,999	16.87	533
1997	717,601.68	418,434	534,957	182,645	17.52	10,425
1998	246,205.62	139,451	178,284	67,921	17.99	3,775
1999	277,503.96	151,739	193,994	83,510	18.65	4,478
2000	44,301.76	23,431	29,956	14,346	19.15	749
2001	178,930.70	91,326	116,758	62,173	19.66	3,162
2002	90,388.68	44,417	56,786	33,603	20.18	1,665
2003	33,809.51	15,951	20,393	13,417	20.71	648
2004	729,490.49	328,125	419,499	309,992	21.41	14,479
2005	700,704.90	300,602	384,312	316,393	21.96	14,408
2006	228,104.68	92,975	118,866	109,239	22.52	4,851
2007	124,971.14	48,201	61,624	63,347	23.09	2,743
2008	652,664.24	237,896	304,144	348,521	23.54	14,805
2009	320,397.52	109,320	139,763	180,635	24.13	7,486
2010	122,302.84	38,819	49,629	72,674	24.73	2,939
2011	81,820.18	24,055	30,754	51,067	25.21	2,026
2012	15,371.28	4,147	5,302	10,069	25.71	392
2013	153,302.63	37,528	47,979	105,324	26.22	4,017
2014	186,396.80	40,821	52,189	134,208	26.75	5,017
2015	352,468.52	68,026	86,969	265,499	27.17	9,772

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG - OTHER STRUCTURES						
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. 0						
2016	261,508.99	43,437	55,533	205,976	27.61	7,460
2017	94,153.21	13,050	16,684	77,469	27.97	2,770
2018	298,796.30	33,047	42,250	256,547	28.15	9,114
2019	200,040.33	16,243	20,766	179,274	28.27	6,341
2020	789,138.96	40,088	51,251	737,888	28.00	26,353
2021	809,794.72	15,062	19,256	790,538	26.45	29,888
	8,620,824.50	3,043,183	3,848,924	4,771,900		196,229
	105,260,871.51	35,887,089	39,865,784	65,395,088		2,930,792

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.3 2.78

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	10,131.48	9,878	4,994	5,137	0.50	5,137
2003	58,882.74	54,467	27,539	31,344	1.50	20,896
2004	19,545.79	17,103	8,647	10,898	2.50	4,359
2005	12,973.40	10,703	5,412	7,562	3.50	2,161
2006	15,741.19	12,199	6,168	9,573	4.50	2,127
2007	98,862.25	71,675	36,240	62,623	5.50	11,386
2008	10,904.48	7,361	3,722	7,183	6.50	1,105
2009	196,763.79	122,977	62,178	134,585	7.50	17,945
2010	29,674.64	17,063	8,627	21,047	8.50	2,476
2013	49,177.44	20,900	10,567	38,610	11.50	3,357
2014	164,928.32	61,848	31,271	133,657	12.50	10,693
2015	142,233.63	46,226	23,372	118,861	13.50	8,805
2016	156,448.43	43,023	21,753	134,696	14.50	9,289
2017	694,772.06	156,324	79,039	615,733	15.50	39,725
2018	365,293.03	63,926	32,322	332,971	16.50	20,180
2019	260,157.81	32,520	16,442	243,715	17.50	13,927
2020	235,363.22	17,652	8,925	226,438	18.50	12,240
2021	186,194.50	4,655	2,354	183,841	19.50	9,428
	2,708,048.20	770,500	389,573	2,318,475		195,236
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	57,421.92	55,986	55,980	1,442	0.50	1,442
2003	12,589.63	11,645	11,644	946	1.50	631
2004	826.89	724	724	103	2.50	41
2005	1,086.91	897	897	190	3.50	54
2006	1,234.22	957	957	277	4.50	62
2007	1,312.22	951	951	361	5.50	66
2008	24,417.03	16,481	16,479	7,938	6.50	1,221
2010	2,239.24	1,288	1,288	951	8.50	112
2011	20,678.25	10,856	10,855	9,823	9.50	1,034
2014	33,759.66	12,660	12,659	21,101	12.50	1,688
2015	35,177.20	11,433	11,432	23,745	13.50	1,759
2016	233,275.70	64,151	64,145	169,131	14.50	11,664
2017	400,100.57	90,023	90,014	310,087	15.50	20,006
2018	31,187.62	5,458	5,457	25,730	16.50	1,559

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2019	69,735.23	8,717	8,716	61,019	17.50	3,487
2020	115,739.37	8,680	8,679	107,060	18.50	5,787
2021	61,990.92	1,550	1,550	60,441	19.50	3,100
	1,102,772.58	302,457	302,427	800,346		53,713
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	17,492.16	17,055	16,255	1,237	0.50	1,237
2003	2,532.25	2,342	2,232	300	1.50	200
2004	11,966.55	10,471	9,980	1,987	2.50	795
2006	1,393.32	1,080	1,029	364	4.50	81
2007	4,828.41	3,501	3,337	1,492	5.50	271
2010	1,926.82	1,108	1,056	871	8.50	102
2014	4,225.61	1,585	1,511	2,715	12.50	217
2015	64,028.79	20,809	19,833	44,196	13.50	3,274
2016	22,950.78	6,311	6,015	16,936	14.50	1,168
2017	29,884.80	6,724	6,409	23,476	15.50	1,515
2018	66,579.64	11,651	11,105	55,475	16.50	3,362
2019	9,728.37	1,216	1,159	8,569	17.50	490
2020	395,875.29	29,691	28,299	367,577	18.50	19,869
2021	17,352.44	434	414	16,939	19.50	869
	650,765.23	113,978	108,633	542,132		33,450
	4,461,586.01	1,186,935	800,633	3,660,953		282,399

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.0 6.33

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	4,313.90	2,804	3,121	1,193	3.50	341
2016	42,502.55	23,376	26,015	16,488	4.50	3,664
2017	3,747.59	1,686	1,876	1,871	5.50	340
2020	18,196.00	2,729	3,037	15,159	8.50	1,783
2021	30,929.53	1,546	1,721	29,209	9.50	3,075
	99,689.57	32,141	35,769	63,920		9,203
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	6,467.49	6,467	6,467			
2013	1,637.58	1,392	1,202	436	1.50	291
2015	7,913.29	5,144	4,441	3,472	3.50	992
2016	5,541.48	3,048	2,632	2,910	4.50	647
2017	8,554.22	3,849	3,323	5,231	5.50	951
2018	2,800.72	980	846	1,955	6.50	301
2021	67,496.24	3,375	2,914	64,582	9.50	6,798
	100,411.02	24,255	21,826	78,585		9,980
	200,100.59	56,396	57,595	142,505		19,183

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.4 9.59

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS SURVIVOR CURVE.. 5-SQUARE NET SALVAGE PERCENT.. 0						
2021	20,690.72	2,069		20,691	4.50	4,598
	20,690.72	2,069		20,691		4,598
PNG SURVIVOR CURVE.. 5-SQUARE NET SALVAGE PERCENT.. 0						
2018	285,879.24	200,115	87,872	198,007	1.50	132,005
2021	46,130.82	4,613	2,026	44,105	4.50	9,801
	332,010.06	204,728	89,898	242,112		141,806
CPG SURVIVOR CURVE.. 5-SQUARE NET SALVAGE PERCENT.. 0						
2017	356,493.12	320,844	344,257	12,236	0.50	12,236
2018	289,585.10	202,710	217,503	72,083	1.50	48,055
2021	20,690.76	2,069	2,220	18,471	4.50	4,105
	666,768.98	525,623	563,980	102,789		64,396
	1,019,469.76	732,420	653,878	365,592		210,800

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.7   20.68

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	3,851,104.16	3,851,104	3,851,104			
2010	527,193.34	527,193	482,087	45,106		
	4,378,297.50	4,378,297	4,333,192	45,106		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - SEDANS AND SUV'S

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2020	860,461.38	189,302	291,061	569,401	5.32	107,030
2021	1,151,232.61	86,112	132,401	1,018,831	6.18	164,859
	2,011,693.99	275,414	423,462	1,588,232		271,889
PNG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2018	314,316.45	149,929	132,100	182,216	3.84	47,452
2020	84,549.74	18,601	16,389	68,161	5.32	12,812
	398,866.19	168,530	148,489	250,377		60,264
CPG						
SURVIVOR CURVE.. IOWA 8-L2.5						
NET SALVAGE PERCENT.. 0						
2006	41,293.53	38,659	40,270	1,024	1.06	966
2019	72,209.78	25,649	26,718	45,492	4.54	10,020
2020	89,863.00	19,770	20,594	69,269	5.32	13,020
2021	94,951.61	7,102	7,398	87,554	6.18	14,167
	298,317.92	91,180	94,979	203,339		38,173
	2,708,878.10	535,124	666,930	2,041,948		370,326

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5 13.67

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.2 TRANSPORTATION EQUIPMENT - SMALL PICK-UPS AND CARGO VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	243,833.01	139,204	214,033	29,800	4.13	7,215
2018	1,528,160.45	601,178	924,340	603,821	5.40	111,819
2019	570,621.57	165,024	253,732	316,889	6.14	51,611
2020	4,884,839.77	866,082	1,331,642	3,553,198	6.96	510,517
2021	727,234.55	43,489	66,866	660,368	7.85	84,123
	7,954,689.35	1,814,977	2,790,613	5,164,077		765,285
PNG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2016	880,256.36	502,538	442,779	437,478	4.13	105,927
2018	628,832.36	247,383	217,965	410,867	5.40	76,086
2019	1,730,886.11	500,572	441,046	1,289,840	6.14	210,072
2020	3,634,685.16	644,430	567,798	3,066,888	6.96	440,645
2021	741,544.46	44,344	39,071	702,474	7.85	89,487
	7,616,204.45	1,939,267	1,708,659	5,907,545		922,217
CPG						
SURVIVOR CURVE.. IOWA 10-L2.5						
NET SALVAGE PERCENT.. 0						
2004	16,397.49	14,979	15,603	794	1.66	478
2005	69,256.31	62,275	64,870	4,386	1.85	2,371
2006	185,611.31	164,266	171,111	14,500	2.01	7,214
2009	132,460.90	109,784	114,359	18,102	2.58	7,016
2010	20,123.95	16,268	16,946	3,178	2.73	1,164
2019	1,476,187.74	426,913	444,702	1,031,485	6.14	167,994
2020	3,331,496.54	590,674	615,287	2,716,209	6.96	390,260
2021	465,177.05	27,818	28,977	436,200	7.85	55,567
	5,696,711.29	1,412,977	1,471,855	4,224,856		632,064
	21,267,605.09	5,167,221	5,971,127	15,296,478		2,319,566

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.6   10.91

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.3 TRANSPORTATION EQUIPMENT - LARGE PICK-UPS AND UTILITY VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS SURVIVOR CURVE.. IOWA 12-L3 NET SALVAGE PERCENT.. 0						
2019	151,470.08	35,565	54,683	96,787	8.15	11,876
	151,470.08	35,565	54,683	96,787		11,876
PNG SURVIVOR CURVE.. IOWA 12-L3 NET SALVAGE PERCENT.. 0						
2018	466,691.13	151,908	133,844	332,847	7.25	45,910
2020	471,241.55	66,634	58,710	412,531	9.10	45,333
	937,932.68	218,542	192,554	745,379		91,243
CPG SURVIVOR CURVE.. IOWA 12-L3 NET SALVAGE PERCENT.. 0						
2004	156,716.35	139,321	145,127	11,590	2.19	5,292
2005	88,086.17	76,882	80,086	8,000	2.40	3,333
2006	213,621.57	182,775	190,391	23,230	2.62	8,866
2019	603,388.00	141,676	147,580	455,808	8.15	55,927
2020	491,779.07	69,538	72,436	419,343	9.10	46,082
	1,553,591.16	610,192	635,619	917,972		119,500
	2,642,993.92	864,299	882,856	1,760,138		222,619

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.9 8.42

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.4 TRANSPORTATION EQUIPMENT - LARGE TRUCKS AND DUMP TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	535,638.12	174,350	268,071	267,567	7.25	36,906
2019	381,787.38	89,644	137,832	243,955	8.15	29,933
2020	507,065.53	71,699	110,241	396,825	9.10	43,607
2021	308,050.51	14,540	22,356	285,695	10.09	28,315
	1,732,541.54	350,233	538,500	1,194,042		138,761
PNG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2018	425,376.84	138,460	121,995	303,382	7.25	41,846
2019	314,507.36	73,846	65,065	249,443	8.15	30,607
2020	346,472.52	48,991	43,165	303,307	9.10	33,330
	1,086,356.72	261,297	230,225	856,132		105,783
CPG						
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. 0						
2001	60,415.29	56,229	58,572	1,843	1.53	1,205
2002	82,337.38	75,619	78,770	3,567	1.73	2,062
2005	284,538.01	248,345	258,693	25,845	2.40	10,769
2019	305,665.05	71,770	74,761	230,904	8.15	28,332
2020	514,813.65	72,795	75,828	438,985	9.10	48,240
	1,247,769.38	524,758	546,624	701,145		90,608
	4,066,667.64	1,136,288	1,315,349	2,751,319		335,152

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.2   8.24

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2012	16,490.72	10,168	15,634	857	5.91	145
2016	325,609.19	135,746	208,716	116,894	7.69	15,201
2019	26,522.13	5,424	8,340	18,182	9.72	1,871
	368,622.04	151,338	232,689	135,933		17,217
PNG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1985	5,500.00	5,360	4,723	777	0.95	777
1998	6,700.32	5,857	5,161	1,540	3.38	456
2004	1,216.16	964	849	367	4.57	80
2011	49,119.84	31,928	28,131	20,989	5.65	3,715
2018	76,939.46	21,512	18,954	57,986	9.02	6,429
2020	301,339.87	37,667	33,188	268,152	10.50	25,538
2021	338,233.43	14,240	12,547	325,687	11.38	28,619
	779,049.08	117,528	103,552	675,497		65,614
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
1994	2,795.60	2,552	2,658	137	2.62	52
2001	39,428.61	32,978	34,352	5,076	4.01	1,266
2002	6,068.45	4,994	5,202	866	4.20	206
2003	17,512.06	14,157	14,747	2,765	4.38	631
2004	42,947.59	34,049	35,468	7,480	4.57	1,637
2005	177,000.31	137,565	143,297	33,703	4.73	7,125
2006	20,800.27	15,829	16,489	4,312	4.87	885
2009	13,098.80	9,202	9,585	3,513	5.29	664
2017	7,110.94	2,493	2,597	4,514	8.34	541

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 392.5 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2019	69,640.53	14,241	14,834	54,806	9.72	5,638
2020	140,654.28	17,582	18,315	122,340	10.50	11,651
2021	247,174.78	10,406	10,840	236,335	11.38	20,768
	784,232.22	296,048	308,384	475,848		51,064
	1,931,903.34	564,914	644,625	1,287,278		133,895

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.6 6.93

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 393 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	1,768.11	1,547	1,560	208	2.50	83
	1,768.11	1,547	1,560	208		83
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	5,589.99	2,096	2,098	3,492	12.50	279
2018	10,248.45	1,793	1,795	8,454	16.50	512
	15,838.44	3,889	3,893	11,946		791
	17,606.55	5,436	5,453	12,154		874

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.9 4.96

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	160,394.15	156,384	159,676	719	0.50	719
2003	344,961.13	319,089	325,805	19,156	1.50	12,771
2004	376,497.34	329,435	336,369	40,128	2.50	16,051
2005	585,131.98	482,734	492,895	92,237	3.50	26,353
2006	533,535.20	413,490	422,193	111,342	4.50	24,743
2007	637,237.38	461,997	471,721	165,516	5.50	30,094
2008	236,121.16	159,382	162,737	73,385	6.50	11,290
2009	267,438.49	167,149	170,667	96,771	7.50	12,903
2010	162,964.81	93,705	95,677	67,288	8.50	7,916
2011	451,363.00	236,966	241,954	209,409	9.50	22,043
2012	368,654.37	175,111	178,797	189,858	10.50	18,082
2013	792,113.30	336,648	343,734	448,380	11.50	38,990
2014	476,076.46	178,529	182,287	293,790	12.50	23,503
2015	1,648,297.12	535,697	546,972	1,101,325	13.50	81,580
2016	1,270,294.92	349,331	356,684	913,611	14.50	63,008
2017	1,830,420.92	411,845	420,513	1,409,907	15.50	90,962
2018	915,728.07	160,252	163,625	752,103	16.50	45,582
2019	1,013,890.01	126,736	129,404	884,486	17.50	50,542
2020	1,692,662.34	126,950	129,622	1,563,040	18.50	84,489
2021	1,785,140.52	44,629	45,568	1,739,572	19.50	89,209
	15,548,922.67	5,266,059	5,376,898	10,172,024		750,830
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	75,121.24	73,243	73,352	1,770	0.50	1,770
2003	110,682.26	102,381	102,533	8,149	1.50	5,433
2004	270,994.91	237,121	237,473	33,522	2.50	13,409
2005	107,276.26	88,503	88,634	18,642	3.50	5,326
2006	272,070.63	210,855	211,168	60,903	4.50	13,534
2007	397,958.98	288,520	288,948	109,011	5.50	19,820
2008	194,881.81	131,545	131,740	63,142	6.50	9,714
2009	386,652.36	241,658	242,017	144,636	7.50	19,285
2010	528,508.76	303,893	304,344	224,165	8.50	26,372
2011	46,412.17	24,366	24,402	22,010	9.50	2,317
2012	106,370.79	50,526	50,601	55,770	10.50	5,311
2013	245,409.98	104,299	104,454	140,956	11.50	12,257
2014	495,061.18	185,648	185,924	309,138	12.50	24,731
2015	960,119.93	312,039	312,502	647,618	13.50	47,972

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 394 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PNG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2016	582,263.35	160,122	160,360	421,904	14.50	29,097
2017	608,859.13	136,993	137,196	471,663	15.50	30,430
2018	1,012,779.35	177,236	177,499	835,280	16.50	50,623
2019	536,030.46	67,004	67,103	468,927	17.50	26,796
2020	1,296,129.90	97,210	97,354	1,198,776	18.50	64,799
2021	1,226,021.61	30,651	30,697	1,195,325	19.50	61,299
	9,459,605.06	3,023,813	3,028,302	6,431,303		470,295
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	448,842.90	437,622	362,754	86,089	0.50	86,089
2003	190,336.67	176,061	145,941	44,396	1.50	29,597
2004	403,566.38	353,121	292,709	110,857	2.50	44,343
2005	471,228.17	388,763	322,254	148,974	3.50	42,564
2006	277,067.07	214,727	177,992	99,075	4.50	22,017
2007	507,181.09	367,706	304,799	202,382	5.50	36,797
2008	544,153.86	367,304	304,466	239,688	6.50	36,875
2009	190,844.18	119,278	98,872	91,972	7.50	12,263
2010	675,112.97	388,190	321,779	353,334	8.50	41,569
2011	41,307.18	21,686	17,976	23,331	9.50	2,456
2012	185,811.11	88,260	73,161	112,651	10.50	10,729
2013	268,626.03	114,166	94,635	173,991	11.50	15,130
2014	510,814.37	191,555	158,784	352,030	12.50	28,162
2015	362,285.21	117,743	97,600	264,686	13.50	19,606
2016	632,442.31	173,922	144,168	488,275	14.50	33,674
2017	243,698.39	54,832	45,451	198,247	15.50	12,790
2018	534,429.05	93,525	77,525	456,904	16.50	27,691
2019	795,631.49	99,454	82,439	713,192	17.50	40,754
2020	463,388.36	34,754	28,808	434,580	18.50	23,491
2021	934,658.67	23,366	19,369	915,290	19.50	46,938
	8,681,425.46	3,826,035	3,171,480	5,509,945		613,535
	33,689,953.19	12,115,907	11,576,681	22,113,272		1,834,660

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.1 5.45

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 395 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	552.73	180	174	379	13.50	28
2016	1,085.72	299	288	797	14.50	55
2017	330,397.55	74,339	71,724	258,673	15.50	16,689
2018	105,742.64	18,505	17,854	87,888	16.50	5,327
	437,778.64	93,323	90,041	347,738		22,099

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.7 5.05

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2000	6,498.36	5,518	6,116	382	3.82	100
2001	30,317.91	25,358	28,108	2,210	4.01	551
2002	3,719.59	3,061	3,393	327	4.20	78
2003	35,492.23	28,692	31,804	3,689	4.38	842
2004	54,943.24	43,559	48,283	6,660	4.57	1,457
2005	14,736.28	11,453	12,695	2,041	4.73	432
2006	28,808.32	21,923	24,301	4,508	4.87	926
2007	37,931.66	28,214	31,274	6,658	4.99	1,334
2009	64,652.45	45,418	50,344	14,309	5.29	2,705
2013	15,373.86	8,874	9,836	5,537	6.23	889
2018	220,480.47	61,646	68,331	152,149	9.02	16,868
2019	308,929.87	63,176	70,027	238,902	9.72	24,578
2020	1,614,013.94	201,752	223,632	1,390,382	10.50	132,417
2021	76,359.04	3,215	3,564	72,795	11.38	6,397
	2,512,257.22	551,859	611,708	1,900,550		189,574
PNG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2003	68,109.74	55,060	67,968	142	4.38	32
2004	167,248.57	132,595	163,679	3,569	4.57	781
2007	13,369.18	9,944	12,275	1,094	4.99	219
2008	35,075.31	25,380	31,330	3,745	5.16	726
2009	48,114.46	33,800	41,724	6,391	5.29	1,208
2010	12,089.03	8,189	10,109	1,980	5.48	361
2018	1,346,981.57	376,616	464,907	882,075	9.02	97,791
2020	783,198.88	97,900	120,851	662,348	10.50	63,081
2021	45,428.50	1,913	2,361	43,067	11.38	3,784
	2,519,615.24	741,397	915,204	1,604,411		167,983
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2001	21,592.29	18,060	13,457	8,136	4.01	2,029
2002	30,786.38	25,334	18,876	11,910	4.20	2,836
2003	50,494.67	40,820	30,415	20,080	4.38	4,584
2004	106,224.95	84,215	62,749	43,476	4.57	9,513

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 396 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. IOWA 15-L2						
NET SALVAGE PERCENT.. 0						
2005	199,925.67	155,382	115,776	84,150	4.73	17,791
2006	32,646.90	24,844	18,511	14,136	4.87	2,903
2009	69,039.30	48,500	36,138	32,902	5.29	6,220
2018	909.08	254	189	720	9.02	80
2019	106,125.88	21,703	16,171	89,955	9.72	9,255
2020	920,993.58	115,124	85,779	835,214	10.50	79,544
	1,538,738.70	534,236	398,061	1,140,677		134,755
	6,570,611.16	1,827,492	1,924,973	4,645,638		492,312

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.4   7.49

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 397 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	82,937.84	78,791	78,140	4,798	0.50	4,798
2013	31,838.36	27,063	26,839	4,999	1.50	3,333
2021	40,712.05	2,036	2,019	38,693	9.50	4,073
	155,488.25	107,890	106,998	48,490		12,204
PNG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	713,351.62	321,008	209,248	504,103	5.50	91,655
2019	33,841.70	8,460	5,515	28,327	7.50	3,777
2021	50,379.19	2,519	1,642	48,737	9.50	5,130
	797,572.51	331,987	216,405	581,167		100,562
CPG						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	151.47	114	151			
2015	28,671.36	18,636	28,671			
2017	17,961.49	8,083	17,961			
2021	21,890.53	1,095	3,013	18,878	9.50	1,987
	68,674.85	27,928	49,797	18,878		1,987
	1,021,735.61	467,805	373,200	648,535		114,753

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.7 11.23

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI-GAS						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	102,456.20	64,889	41,532-	143,989	5.50	26,180
2013	51,777.87	29,341	18,780-	70,558	6.50	10,855
2014	178,624.07	89,312	57,164-	235,788	7.50	31,438
2015	39,471.49	17,104	10,947-	50,419	8.50	5,932
2016	32,235.43	11,820	7,565-	39,801	9.50	4,190
2017	165,977.94	49,793	31,870-	197,848	10.50	18,843
2018	106,282.35	24,799	15,873-	122,155	11.50	10,622
2020	146,222.17	14,622	9,359-	155,581	13.50	11,525
	823,047.52	301,680	193,091-	1,016,138		119,585
PNG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	137,069.69	132,501	121,233	15,837	0.50	15,837
2008	48,106.71	43,296	39,614	8,493	1.50	5,662
2009	72,298.45	60,248	55,124	17,174	2.50	6,870
2010	346,189.24	265,413	242,842	103,348	3.50	29,528
2011	26,672.91	18,671	17,083	9,590	4.50	2,131
2012	6,969.59	4,414	4,039	2,931	5.50	533
2014	262,109.02	131,055	119,910	142,199	7.50	18,960
2016	184,658.73	67,709	61,951	122,708	9.50	12,917
2017	64,069.97	19,221	17,586	46,484	10.50	4,427
2018	1,869.95	436	399	1,471	11.50	128
2020	61,699.27	6,170	5,645	56,054	13.50	4,152
	1,211,713.53	749,134	685,426	526,288		101,145
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2007	6,481.84	6,266	5,798	684	0.50	684
2009	19,072.92	15,894	14,707	4,366	2.50	1,746
2010	46,085.64	35,332	32,694	13,391	3.50	3,826
2011	70,068.25	49,048	45,386	24,682	4.50	5,485
2012	14,758.99	9,347	8,649	6,110	5.50	1,111
2014	2,414.03	1,207	1,117	1,297	7.50	173
2015	4,956.48	2,148	1,988	2,969	8.50	349
2016	65,279.25	23,936	22,149	43,130	9.50	4,540

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CPG						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	81,771.73	24,532	22,700	59,071	10.50	5,626
2018	4,477.95	1,045	967	3,511	11.50	305
2019	1,267.76	211	195	1,073	12.50	86
2020	4,259.10	426	394	3,865	13.50	286
	320,893.94	169,392	156,746	164,148		24,217
	2,355,654.99	1,220,206	649,080	1,706,574		244,947

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.0 10.40

UGI UTILITIES, INC. - GAS DIVISION

ACCOUNT 399 OTHER TANGIBLE PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI - GAS						
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	16,032.00	16,032	16,032			
	16,032.00	16,032	16,032			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

COMMON PLANT

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
UGI HEADQUARTERS BUILDING						
INTERIM SURVIVOR CURVE.. IOWA 70-R1						
PROBABLE RETIREMENT YEAR.. 1-2069						
NET SALVAGE PERCENT.. 0						
2019	30,037,912.33	2,207,787	1,844,004	28,193,908	31.51	894,761
2020	1,907,500.04	90,416	75,518	1,831,982	30.15	60,762
2021	671,173.69	12,350	10,315	660,859	26.75	24,705
	32,616,586.06	2,310,553	1,929,837	30,686,749		980,228

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.3 3.01

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2003	7,182.75	6,644	5,587	1,596	1.50	1,064
2004	11,896.38	10,409	8,753	3,143	2.50	1,257
2005	39,965.68	32,972	27,725	12,241	3.50	3,497
2006	2,468.81	1,913	1,609	860	4.50	191
2007	878.14	637	536	342	5.50	62
2008	572.40	386	325	247	6.50	38
2009	4,753.12	2,971	2,498	2,255	7.50	301
2010	747,318.56	429,708	361,325	385,994	8.50	45,411
2019	3,525,485.48	440,686	370,556	3,154,929	17.50	180,282
2020	27,303.10	2,048	1,722	25,581	18.50	1,383
	4,367,824.42	928,374	780,636	3,587,188		233,486

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.4 5.35

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	51,352.74	46,217	27,861	23,492	0.50	23,492
2018	88,618.09	62,033	37,395	51,223	1.50	34,149
2019	277,204.74	138,602	83,552	193,653	2.50	77,461
2021	1,076,384.85	107,638	64,887	1,011,498	4.50	224,777
	1,493,560.42	354,490	213,695	1,279,865		359,879

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.6   24.10

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 392.1 TRANSPORTATION EQUIPMENT - CARS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L2.5						
NET SALVAGE PERCENT.. 0						
2004	26,875.84	26,478	26,876			
2008	22,536.44	21,114	22,536			
2014	22,224.80	17,635	22,225			
	71,637.08	65,227	71,637			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

UGI UTILITIES, INC. - COMMON PLANT

ACCOUNT 398 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2020	27,967.27	4,195	669	27,298	8.50	3,212
	27,967.27	4,195	669	27,298		3,212

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5   11.48

INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2002	6,694.08	6,527	6,493	201	0.50	201
2003	22,684.22	20,983	20,873	1,811	1.50	1,207
2004	5,698.56	4,986	4,960	739	2.50	296
2007	1,760.05	1,276	1,269	491	5.50	89
	36,836.91	33,772	33,595	3,242		1,793

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.8   4.87

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.1 OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2017	4,328,639.39	3,895,775	3,817,774	510,865	0.50	510,865
2018	5,584,430.57	3,909,101	3,830,833	1,753,598	1.50	1,169,065
2019	9,507,270.50	4,753,635	4,658,457	4,848,814	2.50	1,939,526
2020	1,980,934.07	594,280	582,381	1,398,553	3.50	399,587
2021	504,089.49	50,409	49,400	454,689	4.50	101,042
	21,905,364.02	13,203,200	12,938,845	8,966,519		4,120,085

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.2 18.81

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.2 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SUCCESS FACTORS INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2024 NET SALVAGE PERCENT.. 0						
2019	2,803,866.07	1,274,497	622,437	2,181,429	3.00	727,143
	2,803,866.07	1,274,497	622,437	2,181,429		727,143
UNITE ERP INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 9-2034 NET SALVAGE PERCENT.. 0						
2019	10,695,816.43	1,725,128	842,516	9,853,300	13.00	757,946
	10,695,816.43	1,725,128	842,516	9,853,300		757,946
	13,499,682.50	2,999,625	1,464,953	12,034,729		1,485,089

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.1 11.00

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.3 OFFICE FURNITURE AND EQUIPMENT - SYSTEM DEV. COSTS - 10 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
ALL OTHER						
SURVIVOR CURVE.. 10-SQUARE						
NET SALVAGE PERCENT.. 0						
2012	2,992,697.57	2,843,063	2,547,027	445,670	0.50	445,670
2013	381,964.34	324,670	290,864	91,101	1.50	60,734
2014	988,604.39	741,453	664,249	324,356	2.50	129,742
2015	732,102.69	475,867	426,317	305,786	3.50	87,367
2016	930,430.13	511,737	458,452	471,978	4.50	104,884
2017	1,349,992.48	607,497	544,241	805,751	5.50	146,500
2018	1,384,581.24	484,603	434,143	950,438	6.50	146,221
2019	7,509,579.44	1,877,395	1,681,910	5,827,669	7.50	777,023
2020	13,110,042.00	1,966,506	1,761,742	11,348,300	8.50	1,335,094
2021	6,971,595.51	348,580	312,284	6,659,312	9.50	700,980
	36,351,589.79	10,181,371	9,121,230	27,230,360		3,934,215
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
2000	802,205.51	802,206	802,206			
2001	18,799.62	18,800	18,800			
2002	447,659.05	447,659	447,659			
2004	1,403,264.52	1,403,265	1,403,265			
2005	122,880.00	122,880	122,880			
2006	2,416,650.18	2,416,650	2,416,650			
2007	3,259,581.05	3,259,581	3,259,581			
2008	259,506.50	259,506	259,507			
2009	481,827.39	481,827	481,827			
2010	324,586.33	324,586	324,586			
2011	24,265.04	24,265	24,265			
	9,561,225.19	9,561,225	9,561,225			
	45,912,814.98	19,742,596	18,682,455	27,230,360		3,934,215

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.9   8.57

UGI UTILITIES, INC. - INFORMATION SERVICES

ACCOUNT 391.4 OFFICE FURNITURE AND EQUIPMENT - SOFTWARE - SYSTEM DEV. COSTS - 15 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2005	867,789.26	867,789	867,789			
2006	1,660,897.57	1,660,898	1,660,898			
2007	3,042,652.35	2,941,241	2,873,594	169,058	0.50	169,058
2008	2,908,998.47	2,618,099	2,557,885	351,113	1.50	234,075
2011	425,873.07	298,111	291,255	134,618	4.50	29,915
2012	401,290.13	254,149	248,304	152,986	5.50	27,816
2013	142,364.69	80,674	78,819	63,546	6.50	9,776
2014	495,556.48	247,778	242,079	253,477	7.50	33,797
2016	1,419,264.44	520,402	508,433	910,831	9.50	95,877
2017	76,271,826.62	22,881,548	22,355,287	53,916,540	10.50	5,134,909
2018	171,914.66	40,113	39,190	132,725	11.50	11,541
2019	43,689,680.34	7,281,759	7,114,284	36,575,396	12.50	2,926,032
2021	6,526,337.79	217,523	212,520	6,313,818	14.50	435,436
	138,024,445.87	39,910,084	39,050,337	98,974,109		9,108,232

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.9 6.60

READING SERVICE CENTER – INFORMATION SERVICES

UGI UTILITIES, INC. - INFORMATION SERVICES
READING SERVICE CENTER

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2030						
NET SALVAGE PERCENT.. 0						
1974	574,897.52	478,930	492,508	82,390	8.44	9,762
1975	7,158.54	5,944	6,113	1,046	8.45	124
1976	1,629.59	1,348	1,386	244	8.46	29
1977	2,106.01	1,736	1,785	321	8.47	38
1978	554.20	455	468	86	8.48	10
1979	6,707.24	5,489	5,645	1,062	8.48	125
1980	28,233.56	23,010	23,662	4,572	8.49	539
1981	44,870.26	36,410	37,442	7,428	8.50	874
1982	427.88	353	363	65	8.37	8
1983	1,273.20	1,042	1,072	201	8.48	24
1984	1,922.47	1,568	1,612	310	8.41	37
1985	15,545.14	12,623	12,981	2,564	8.39	306
1986	1,122.78	906	932	191	8.42	23
1987	100.24	80	82	18	8.49	2
1989	40,014.11	31,615	32,511	7,503	8.57	875
1990	23,330.17	18,300	18,819	4,511	8.59	525
1992	95,013.29	73,645	75,733	19,280	8.49	2,271
1993	1,839.65	1,415	1,455	385	8.52	45
1994	27,141.96	20,677	21,263	5,879	8.60	684
1995	4,582.00	3,460	3,558	1,024	8.59	119
1996	248.50	186	191	58	8.51	7
1998	683.50	501	515	168	8.55	20
2000	72,144.40	51,655	53,120	19,024	8.53	2,230
2001	73,338.56	51,718	53,184	20,155	8.57	2,352
2002	5,526.75	3,837	3,946	1,581	8.59	184
2003	201.42	137	141	60	8.60	7
2004	1,508.64	1,014	1,043	466	8.54	55
2005	4,812.03	3,168	3,258	1,554	8.56	182
2006	458.13	295	303	155	8.60	18
2007	379,291.04	238,119	244,870	134,421	8.60	15,630
2008	444,898.44	272,100	279,815	165,083	8.57	19,263
2009	14,014.85	8,304	8,539	5,476	8.60	637
2010	2,629.36	1,506	1,549	1,080	8.58	126
2011	3,560.30	1,959	2,015	1,545	8.58	180
2012	294.73	155	159	136	8.58	16
2014	5,428.44	2,532	2,604	2,824	8.58	329
2015	44,230.06	19,063	19,603	24,627	8.58	2,870
2016	33,847.95	13,235	13,610	20,238	8.57	2,361
2017	6,680.06	2,303	2,368	4,312	8.55	504

UGI UTILITIES, INC. - INFORMATION SERVICES
READING SERVICE CENTER

ACCOUNT 390.1 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT SEPTEMBER 30, 2021

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 80-R1.5						
PROBABLE RETIREMENT YEAR.. 6-2030						
NET SALVAGE PERCENT.. 0						
2018	41,704.28	12,115	12,459	29,245	8.55	3,420
2019	106,886.32	24,242	24,930	81,956	8.52	9,619
2021	92,336.26	5,226	5,374	86,962	8.33	10,440
	2,213,193.83	1,432,376	1,472,986	740,208		86,870

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.5 3.93

PART IV. EXPERIENCED NET SALVAGE

GAS PLANT

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2017 TRANSACTION YEAR				
305.00		74,121.00		74,121.00-
334.00		2.00		2.00-
352.01		79,852.00		79,852.00-
375.00		35,280.00		35,280.00-
376.00	3,876,659.84	1,778,083.00	9,141.00-	1,787,224.00-
378.00	376,635.63	287,084.00	59,792.00	227,292.00-
380.00	7,311,233.90	5,711,858.00		5,711,858.00-
381.00	2,194,945.78	2,218.00		2,218.00-
382.00	107,571.21	581,870.00		581,870.00-
383.00	60.86	3,530,065.00		3,530,065.00-
384.00	45.28	1,442.00		1,442.00-
385.00	3,929.34	11,977.00		11,977.00-
387.00		7,552.00		7,552.00-
390.10		77,836.00		77,836.00-
390.20		475.00		475.00-
391.10	287,443.63			
391.20	87,057.25			
391.30	269,396.62			
392.00	5,464,895.36	6,339.99	82,010.01	75,670.02
393.00	628.88			
394.00	456,179.68			
395.00	2,330.29			
396.00	889,863.39	663.00	3,100.00	2,437.00
397.00	408,681.96			
398.00	75,609.85	26,099.00		26,099.00-
	21,813,168.75	12,212,816.99	135,761.01	12,077,055.98-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2018 TRANSACTION YEAR				
305.00		6.00-		6.00
369.00		1,147.00		1,147.00-
375.00	3,628.88	184.00-		184.00
376.00	7,446,077.98	2,023,888.00	4,146.00-	2,028,034.00-
378.00	2,639,646.78	339,196.00	216,520.00	122,676.00-
379.00	1,601,657.00			
380.00	6,753,826.12	5,717,004.00		5,717,004.00-
381.00	752,001.53	3,138.00		3,138.00-
382.00	76,914.85	328,078.00		328,078.00-
383.00	14.70	1,356,927.00		1,356,927.00-
384.00	1.19	688.00		688.00-
385.00	105,397.38	25,192.00		25,192.00-
390.10	37,749.37	705.00-		705.00
391.10	483,301.05			
391.20	67,874.16			
391.30	3,178.26			
392.00	597,553.59	189.00		189.00-
394.00	503,324.51			
395.00	4,297.81			
396.00	2,535,519.08			
397.00	328,054.14			
398.00	17,212.65	3,075.00		3,075.00-
	23,957,231.03	9,797,627.00	212,374.00	9,585,253.00-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2019 TRANSACTION YEAR				
369.00		131.00		131.00-
376.00	2,599,001.00	440,534.00	62,338.00	378,196.00-
378.00	159,150.00	154,135.00	15,813.00	138,322.00-
379.00	231,613.00			
380.00	8,211,461.00	3,425,191.00		3,425,191.00-
381.00	1,090,648.00	770.00		770.00-
382.00	72,768.00	262,633.00		262,633.00-
383.00		54,424.00-		54,424.00
384.00		2.00-		2.00
385.00		4,047.00		4,047.00-
390.10		76,973.00		76,973.00-
391.10	461,640.00			
391.20	75,179.00			
391.30	5,022.00			
391.40	3,295,776.00			
393.00	774.00			
394.00	609,662.00			
397.00	111,549.00			
398.00	76,034.00	652.00		652.00-
	17,000,277.00	4,310,640.00	78,151.00	4,232,489.00-
2020 TRANSACTION YEAR				
376.00	6,459,698.00	1,030,068.00		1,030,068.00-
378.00	2,984.00	29,723.00		29,723.00-
380.00	11,637,744.00	4,911,297.00		4,911,297.00-
381.00	904,135.00			
382.00		1,144,545.00		1,144,545.00-
383.00		2,130.00		2,130.00-
384.00		515,427.00		515,427.00-
390.10		17,949.00		17,949.00-
391.10	127,130.00			
391.20	33,245.00			
391.30	174,316.00			
392.00			691,071.00	691,071.00
394.00	808,538.00			
397.00	1,182,932.00			
398.00	54,164.00	257,300.00		257,300.00-
	21,384,886.00	7,908,439.00	691,071.00	7,217,368.00-

UGI UTILITIES, INC. - GAS DIVISION

EXPERIENCED RETIREMENTS BY ACCOUNT AND ASSOCIATED
COST OF REMOVAL, GROSS SALVAGE, AND NET SALVAGE

ACCT	REGULAR RETIREMENTS	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE
2021 TRANSACTION YEAR				
305.00			115,195.00	115,195.00
367.00	24.00	1,660.00		1,660.00-
369.00		3,386.00		3,386.00-
375.00	18,008.00			
376.00	4,504,366.00	2,534,160.00		2,534,160.00-
378.00		168,692.00		168,692.00-
379.00		15,105.00		15,105.00-
380.00	12,500,315.00	4,191,361.00		4,191,361.00-
381.00	3,015,928.00	1,237.00	19,201.00	17,964.00
382.00		224,823.00		224,823.00-
383.00		269.00		269.00-
384.00		13,720.00		13,720.00-
385.00		35,290.00		35,290.00-
386.00	269,143.00			
390.10	231,077.00	135.00		135.00-
391.10	661,188.00			
391.20	74,471.00			
391.30	120,424.00			
392.00			526,894.00	526,894.00
393.00	3,091.00			
394.00	869,872.00			
397.00	8,099.00			
398.00	88,752.00	391,820.00		391,820.00-
	22,364,758.00	7,581,658.00	661,290.00	6,920,368.00-
TOTAL	106,520,320.78	41,811,180.99	1,778,647.01	40,032,533.98-

BOOK IX

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT D

COST OF SERVICE ALLOCATION
STUDY AS OF SEPTEMBER 30, 2023

Witness: Constance E. Heppenstall
Prepared by: Gannett Fleming
Valuation and Rate Consultants, LLC

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 **Effective: March 29, 2022**

UGI Gas Exhibit D
Witness: C. E. Heppenstall

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

COST OF SERVICE ALLOCATION STUDY

AS OF SEPTEMBER 30, 2023

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
Camp Hill, Pennsylvania

Gannett Fleming

Excellent Delivered **As Promised**

January 14, 2022

UGI Utilities, Inc. – Gas Division
1 UGI Drive
Denver, PA 17517

Attention: Mr. Paul J. Szykman
Chief Regulatory Officer

Ladies and Gentlemen:

Pursuant to your request, we have prepared a cost of service allocation study based on pro forma revenue requirements for the twelve months ended September 30, 2023, for UGI Utilities, Inc. – Gas Division.

The attached report presents the results of the study, as well as supporting schedules which set forth the detailed allocation calculations. Schedule A, on page 5, presents a comparison of the cost of service by service classification with the revenues produced by each classification under present and proposed rates.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

CONSTANCE E. HEPPENSTALL
Senior Project Manager, Rate Studies

CEH:mle

069215.200

C O N T E N T S

PART I. INTRODUCTION

PART II. COST OF SERVICE BY SERVICE CLASSIFICATION

PART I. INTRODUCTION

UGI UTILITIES, INC. – GAS DIVISION

COST OF SERVICE ALLOCATION STUDY
AS OF SEPTEMBER 30, 2023

PART I. INTRODUCTION

PLAN OF REPORT

The report sets forth the results of the cost of service allocation study prepared for UGI Utilities, Inc. – Gas Division, based on the twelve months ended September 30, 2023 (FPFTY). Part I, Introduction, includes statements with respect to the basis of the study, the procedures employed, and a summary of the results of the study. Part II, Cost of Service by Service Classification, presents the detailed schedules of the allocation of costs to service classifications, the bases for the allocations, and the development of certain customer and demand costs.

BASIS OF THE STUDY

The purpose of the study was to allocate costs of UGI Gas Division to the several customer classifications based on considerations of quantity of gas consumed; sales and transportation; demand characteristics; and costs associated with metering, billing, and accounting. The allocation study was based on recognized procedures for allocating costs to customer classifications in proportion to each classification's use of the facilities, commodity, and services which entail the total cost of providing gas service.

ALLOCATION PROCEDURES

The allocation study was based on the Average and Extra Demand Method for allocating costs to service classifications. The method is identified as the "Average and

Excess Demand Method" in "Gas Rate Fundamentals," (published in 1987 by the American Gas Association's Rate Committee) in which it is described. The three basic categories of cost responsibility are commodity, capacity, and customer costs. In the Average and Extra Demand Method, the capacity costs are allocated to service classifications on a combined basis of average use and use above average at peak demands. The following presents a brief discussion of costs and the manner in which they were allocated.

Commodity Costs are the costs that tend to vary with the quantity of gas used. Commodity costs in this study include production plant expenses and associated costs. Commodity costs were allocated to service classifications on the basis of average daily sales volumes.

Capacity Costs are costs associated with meeting the peak demands of the system. Capacity costs attributable to sales and transportation service include Distribution expenses and capital costs not associated with the customer costs category. The capacity costs were allocated to service classifications on a combined basis of average use and extra demand (demand in excess of average use). For presentation purposes, the commodity and capacity costs are combined into the volumetric function for each classification.

Customer Costs are costs associated with serving customers regardless of their usage or demand characteristics. Customer costs include the expenses and capital costs related to meters, regulators, and services and expenses related to meter reading and billing. The customer costs were allocated to service classifications on the bases of the number of meters, services and customers.

The allocation of costs to service classifications and the bases for the allocations are presented in Part II, Cost of Service by Service Classification.

RESULTS OF STUDY

The data summarized in Schedule A, "Comparison of Cost of Service with Revenues Under Present and Proposed Rates by Service Classification for the Twelve Months Ended September 30, 2023," constitute the principal results of the allocation study. Schedules B through F in Part II of the report present the details of the allocation of costs of service, including the return based on the allocated measure of value, by service classification as well as the bases for the allocation factors. Schedule G presents the development of customer costs per bill by service classification. Schedule H presents a cost analysis of the LFD and XD Service demand charges.

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF COST OF SERVICE WITH REVENUES UNDER PRESENT AND PROPOSED RATES
BY SERVICE CLASSIFICATION FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023
WITHOUT GAS COSTS

Service Classification	Pro Forma Cost of Service Amount	Pro Forma Cost of Service Percent	Pro Forma Margin Revenues, Under Present Rates Amount	Under Present Rates Percent	Under Proposed Rates Amount	Under Proposed Rates Percent	Revenue Increase Amount	Revenue Increase Percent Increase
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Rate R	$ 471,011,760	63.9%	$ 377,368,713	57.5%	$ 445,483,863	60.3%	$ 68,115,150	18.1%
Rate N	146,888,226	19.9%	138,825,398	21.2%	153,278,225	20.8%	14,452,827	10.4%
Rate DS	32,808,421	4.4%	33,778,394	5.2%	34,432,339	4.7%	653,946	1.9%
Rate LFD	41,387,804	5.6%	44,861,623	6.8%	46,392,850	6.3%	1,531,227	3.4%
Rate XD Firm	28,012,485	3.8%	36,697,802	5.6%	35,735,967	4.8%	(961,834)	-2.6%
Interruptible	17,906,171	2.4%	24,012,357	3.7%	22,963,170	3.1%	(1,049,187)	-4.4%
Total	$ 738,014,867	100.0%	$ 655,544,286	100.0%	$ 738,286,415	100.0%	$ 82,742,129	12.6%
Other Operating Revenues	10,287,000		10,287,000		10,287,000		0	
Total	$748,301,867		$665,831,286		$748,573,415		$82,742,129	12.4%

PART II. COST OF SERVICE

BY SERVICE CLASSIFICATION

UGI UTILITIES, INC. - GAS DIVISION

DEVELOPMENT OF RATE OF RETURN BY SERVICE CLASSIFICATION
UNDER PRESENT RATES

Item	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD-Firm	Interruptible
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1. Revenues From Tariff Sales and Transportation	$ 655,544,286	$ 377,368,713	$ 138,825,398	$ 33,778,394	$ 44,861,623	$ 36,697,802	$ 24,012,357
2. Other Revenues	10,286,999	5,777,403	2,977,948	481,908	547,898	296,899	204,943
3. Total Operating Revenues	665,831,285	383,146,116	141,803,346	34,260,302	45,409,521	36,994,701	24,217,300
4. Less: Operating Expenses	431,337,472	287,943,600	76,425,741	18,685,360	21,989,590	17,011,309	9,281,872
5. Return and Income Taxes	234,493,813	95,202,516	65,377,605	15,574,942	23,419,931	19,983,391	14,935,428
6. Less: Interest Expense	56,726,000	33,661,208	13,205,813	2,637,759	3,596,428	2,036,463	1,588,328
7. Taxable Income	177,767,813	61,541,308	52,171,792	12,937,183	19,823,503	17,946,928	13,347,100
8. Less: Income Taxes	39,835,701	13,787,136	11,691,778	2,900,039	4,441,681	4,023,406	2,991,661
9. Net Return (Ln 5 - Ln 8)	194,658,112	81,415,380	53,685,827	12,674,903	18,978,250	15,959,985	11,943,767
10. Original Cost Measure of Value (Factor 15.)	3,169,022,979	1,880,342,949	737,848,937	147,259,085	200,956,223	113,880,658	88,735,127
11. Rate of Return, Percent	6.14%	4.33%	7.28%	8.61%	9.44%	14.01%	13.46%
12. Relative Rate of Return	1.00	0.70	1.18	1.40	1.54	2.28	2.19

UGI UTILITIES, INC. - GAS DIVISION

DEVELOPMENT OF RATE OF RETURN BY SERVICE CLASSIFICATION
UNDER PROPOSED RATES

Item	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD-Firm	Interruptible
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1. Revenues From Tariff Sales and Transportation	$ 738,286,415	$ 445,483,863	$ 153,278,225	$ 34,432,339	$ 46,392,850	$ 35,735,967	$ 22,963,170
2. Other Revenues	10,287,000	5,774,384	2,982,791	481,302	547,754	295,295	205,474
3. Total Operating Revenues	748,573,415	451,258,247	156,261,016	34,913,641	46,940,604	36,031,262	23,168,644
4. Less: Operating Expenses	432,700,222	289,445,008	76,430,514	18,645,807	21,926,414	16,977,680	9,274,799
5. Return and Income Taxes	315,873,193	161,813,239	79,830,502	16,267,835	25,014,190	19,053,582	13,893,845
6. Less: Interest Expense	56,726,000	33,672,554	13,200,140	2,632,086	3,596,428	2,036,463	1,588,328
7. Taxable Income	259,147,193	128,140,685	66,630,362	13,635,749	21,417,762	17,017,119	12,305,517
8. Less: Income Taxes	63,347,000	31,325,092	16,286,514	3,332,052	5,232,462	4,161,898	3,008,983
9. Net Return (Ln 5 - Ln 8)	252,526,193	130,488,147	63,543,988	12,935,783	19,781,728	14,891,684	10,884,862
10. Original Cost Measure of Value (Factor 15.)	3,169,022,979	1,881,075,190	737,530,945	147,139,836	200,820,216	113,761,411	88,695,381
11. Rate of Return, Percent	7.97%	6.94%	8.62%	8.79%	9.85%	13.09%	12.27%
12. Relative Rate of Return	1.00	0.87	1.08	1.10	1.24	1.64	1.54

UGI UTILITIES, INC. - GAS DIVISION

SUMMARY OF COST OF SERVICE BY SERVICE CLASSIFICATION

Cost Function	Cost of Service (Schedule E)	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Volumetric Costs							
Rate R	$ 224,856,157	$ 224,856,157					
Rate N	102,342,701		$ 102,342,701				
Rate DS	24,523,189			$ 24,523,189			
Rate LFD	35,444,083				$ 35,444,083		
Rate XD Firm	26,822,531					$ 26,822,531	
Rate IS/IL	14,900,365						$ 14,900,365
Total Volumetric Costs	428,889,025	224,856,157	102,342,701	24,523,189	35,444,083	26,822,531	14,900,365
Customer Costs							
Rate R	$ 246,155,604	$ 246,155,604					
Rate N	44,545,525		$ 44,545,525				
Rate DS	8,285,232			$ 8,285,232			
Rate LFD	5,943,721				$ 5,943,721		
Rate XD Firm	1,189,954					$ 1,189,954	
Rate IS/IL	3,005,806						$ 3,005,806
Total Customer Costs	309,125,841	246,155,604	44,545,525	8,285,232	5,943,721	1,189,954	3,005,806
Total Excluding Gas Costs	$ 738,014,867	$ 471,011,760	$ 146,888,226	$ 32,808,421	$ 41,387,804	$ 28,012,485	$ 17,906,171

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

				Volumetric Costs						Customer Costs					
	Account	Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
OPERATION AND MAINTENANCE EXPENSES															
NATURAL GAS PRODUCTION EXPENSES															
	Manufactured Gas Production Expenses														
710	Operation Supervision and Engineering	1	0	-	-	-	-	-	-	-	-	-	-	-	-
717	Total Production Labor and Expenses	1	0	-	-	-	-	-	-	-	-	-	-	-	-
725-736	Total Gas Fuels Expenses	1	14,000	10,046	3,954	-	-	-	-	-	-	-	-	-	-
740-742	Total Gas Raw Materials Expenses	1	983,333	705,640	277,693	-	-	-	-	-	-	-	-	-	-
	Total Operation		997,333	715,686	281,647	-	-	-	-	-	-	-	-	-	-
	Production and Gathering														
750 - 760	Total Production & Gathering Operation Exps.	1	-	-	-	-	-	-	-	-	-	-	-	-	-
761 - 769	Total Production & Gathering Maintenance Exps.	1	-	-	-	-	-	-	-	-	-	-	-	-	-
770 - 783	Total Products Extraction Operation Expenses	1	-	-	-	-	-	-	-	-	-	-	-	-	-
784 - 791	Total Products Extraction Maintenance Exps.	1	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Production Expenses		-	-	-	-	-	-	-	-	-	-	-	-	-
	Other Gas Supply Expenses														
800 - 803	Natural Gas Transmission Line Purchases	1	-	-	-	-	-	-	-	-	-	-	-	-	-
804	Natural Gas City Gate Purchases	1	-	-	-	-	-	-	-	-	-	-	-	-	-
805.1	Purchases Gas Cost Adjustments	1	-	-	-	-	-	-	-	-	-	-	-	-	-
805	Other Gas Purchases	1	-	-	-	-	-	-	-	-	-	-	-	-	-
808.1	Gas Withdrawn from Storage-Debit	1	-	-	-	-	-	-	-	-	-	-	-	-	-
808.2	Gas Delivered to Storage-Credit	1	-	-	-	-	-	-	-	-	-	-	-	-	-
812	Gas Used for Operations	1	-	-	-	-	-	-	-	-	-	-	-	-	-
813	Other Gas Supply Expenses	1	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Other Gas Supply Expenses		-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Natural Gas Production Expenses		**997,333**	**715,686**	**281,647**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
OTHER STORAGE EXPENSE															
840	Operating Supervision and Engineering	1A	-	-	-	-	-	-	-	-	-	-	-	-	-
841	Operation Labor and Expenses	4	-	-	-	-	-	-	-	-	-	-	-	-	-
842 - 842.3	Other Operations Expense	4	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Natural Gas Storage Expense		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TRANSMISSION EXPENSE															
850 - 860	Total Transmission Operation Expenses	4	-	-	-	-	-	-	-	-	-	-	-	-	-
861 - 867	Total Transmission Maintenance Expenses	4	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Transmission Expense		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
DISTRIBUTION EXPENSES															
	Operation														
870	Supervision And Engineering	10	5,304,635	1,068,353	699,151	164,974	233,404	343,210	100,788	1,973,324	594,650	57,290	41,907	7,426	20,158
871	Distribution Load Dispatching	4A	2,030	607	403	91	109	780	41	-	-	-	-	-	-
872	Compressor Station Labor and Expenses		-												
873	Compressor Station Fuel and Power	2	-	-	-	-	-	-	-	-	-	-	-	-	-
874	Mains And Services Expenses														
	Mains - Small	4	5,045,247	2,363,698	1,542,837	367,294	535,301	-	236,118	-	-	-	-	-	-
	Mains - Large	17	9,275,884	3,979,354	2,596,320	617,774	900,688	784,740	397,008	-	-	-	-	-	-
	Services	6C	13,256,218	-	-	-	-	-	-	11,556,771	1,592,072	53,025	33,141	3,977	17,233
875	M & R Station Expenses -General	4A	4,226,551	1,263,739	838,970	188,504	226,966	1,623,841	84,531	-	-	-	-	-	-
876	M & R Station Expenses - Industrial	6B	12,194	-	-	-	-	-	-	-	-	5,434	4,065	734	1,961
877	M & R Station Expenses - City Gate Station	4A	115,674	34,587	22,961	5,159	6,212	44,442	2,313	-	-	-	-	-	-
878	Meter and House Regulator Expenses	6	3,245,151	-	-	-	-	-	-	1,381,785	1,437,926	189,517	141,813	25,637	68,473
879	Customer Installations Expenses	6	2,759,655	-	-	-	-	-	-	1,175,061	1,222,803	161,164	120,597	21,801	58,229
880	Other Expenses	10	1,297,033	261,222	170,949	40,338	57,069	83,918	24,644	482,496	145,397	14,008	10,247	1,816	4,929
881	Rents	10	3,117,000	627,764	410,821	96,939	137,148	201,670	59,223	1,159,524	349,416	33,664	24,624	4,364	11,845
881	Rents - Directly Assigned to XD	DA	565,000					565,000							
	Total Operation		48,222,273	9,599,324	6,282,412	1,481,073	2,096,897	3,647,601	904,666	17,728,961	5,342,264	514,102	376,394	65,755	182,828

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

				Volumetric Costs						Customer Costs					
	Account	Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Maintenance														
885	Supervision - Engineering and Labor	11	516,307	184,683	120,661	28,603	41,201	38,052	18,019	18,277	2,530	28,655	21,427	3,872	10,326
886	Structures & Improvements	18	-	-	-	-	-	-	-	-	-	-	-	-	-
887	Mains - Small	4	9,960,460	4,666,476	3,045,909	725,121	1,056,805	-	466,150	-	-	-	-	-	-
	Mains - Large	17	18,312,694	7,856,146	5,125,723	1,219,625	1,778,163	1,549,254	783,783	-	-	-	-	-	-
888	Maintenance of Compressor Station Equipment	4	262,000	122,747	80,120	19,074	27,798	-	12,262	-	-	-	-	-	-
889	M & R Equip - General	4A	3,156,282	943,728	626,522	140,770	169,492	1,212,644	63,126	-	-	-	-	-	-
890	M & R Equip - Industrial	6B	4,732,873	-	-	-	-	-	-	-	-	2,108,968	1,577,940	284,919	761,046
891	M & R Equip - City Gate	4A	121,179	36,233	24,054	5,405	6,507	46,557	2,424	-	-	-	-	-	-
892	Services	6C	1,547,015	-	-	-	-	-	-	1,348,688	185,797	6,188	3,868	464	2,011
893	Meters & House Regulators	6	-	-	-	-	-	-	-	-	-	-	-	-	-
894	Other Expenses	11	555,780	198,803	129,886	30,790	44,351	40,961	19,397	19,675	2,723	30,846	23,065	4,168	11,116
895	Construction and Maintenance	11	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Maintenance		39,164,590	14,008,816	9,152,875	2,169,388	3,124,317	2,887,468	1,365,161	1,386,640	191,050	2,174,657	1,626,300	293,423	784,499
	Total Distribution Expenses		**87,386,863**	**23,608,140**	**15,435,287**	**3,650,461**	**5,221,214**	**6,535,069**	**2,269,827**	**19,115,601**	**5,533,314**	**2,688,759**	**2,002,694**	**359,178**	**967,327**
CUSTOMER ACCOUNTING EXPENSES															
	Operation														
901	Supervision	7	832,203	-	-	-	-	-	-	744,572	84,718	1,664	749	83	416
902	Meter Reading Expenses	7	2,208,095	-	-	-	-	-	-	1,975,583	224,784	4,416	1,987	221	1,104
903	Customer Records & Coll Expenses	7	19,474,018	-	-	-	-	-	-	17,423,404	1,982,455	38,948	17,527	1,947	9,737
903.1	Universal Service Program	DA	17,537,000	17,537,000											
904	Uncollectible Accounts	19	17,957,980	6,465,085	493,184					10,147,842	668,697	14,366	30,529	100,565	37,712
905	Miscellaneous Cust Accts Expenses	7	2,318,249	-	-	-	-	-	-	2,074,137	235,998	4,636	2,086	232	1,159
	Total Customer Accounting Expenses		**60,327,545**	**24,002,085**	**493,184**	**-**	**-**	**-**	**-**	**32,365,538**	**3,196,652**	**64,030**	**52,878**	**103,048**	**50,128**
CUSTOMER SERVICE AND INFORMATION EXPENSES															
	Operation														
907	Supervision	7	174,406	-	-	-	-	-	-	156,041	17,755	349	157	17	87
908	Customer Assistance Expenses	9	714,061	-	-	-	-	-	-	714,061	-	-	-	-	-
909	Informational and Instructional Advertising	7	-	-	-	-	-	-	-	-	-	-	-	-	-
910	Miscellaneous Customer Service & Informational Exp.	7	62,958	-	-	-	-	-	-	56,329	6,409	126	57	6	31
910.1	Energy Efficiency and Conservation Programs	DA	12,717,939	10,801,850	634,636	534,450	747,003								
	Total Customer Service & Info Expenses		**13,669,364**	**10,801,850**	**634,636**	**534,450**	**747,003**	**-**	**-**	**926,431**	**24,164**	**475**	**214**	**23**	**118**
SALES EXPENSES															
	Operation														
911	Supervision	8	431,364	-	-	-	-	-	-	387,279	44,085	-	-	-	-
912	Demonstrating and Selling Expenses	8	(677,610)	-	-	-	-	-	-	(608,358)	(69,252)	-	-	-	-
908/912	Service Representatives	7A	283,600	-	-	-	-	-	-	-	-	163,609	70,758	6,580	42,653
913	Advertising Expenses	8	1,637,284	-	-	-	-	-	-	1,469,954	167,330	-	-	-	-
916	Miscellaneous	8	258,000	-	-	-	-	-	-	231,632	26,368	-	-	-	-
	Total Sales Expenses		**1,932,639**	**-**	**-**	**-**	**-**	**-**	**-**	**1,480,507**	**168,531**	**163,609**	**70,758**	**6,580**	**42,653**
ADMINISTRATIVE AND GENERAL EXPENSES															
	Operation														
920	Administrative & General Salaries	12	36,437,774	13,033,792	3,694,790	932,807	1,329,979	1,457,511	506,485	12,024,465	1,989,502	652,236	473,691	105,670	236,846
921	Office Supplies and Expenses	12	21,222,000	7,591,109	2,151,911	543,283	774,603	848,880	294,986	7,003,260	1,158,721	379,874	275,886	61,544	137,943
922	Administrative Expenses Transferred-Credit														
923	Outside Services Employed - Other	12	25,611,015	9,161,060	2,596,957	655,642	934,802	1,024,441	355,993	8,451,635	1,398,361	458,437	332,943	74,272	166,472
924	Property Damage Insurance	12	-	-	-	-	-	-	-	-	-	-	-	-	-
925	Injuries and Damages	12	10,371,987	3,710,060	1,051,719	265,523	378,578	414,879	144,171	3,422,756	566,310	185,659	134,836	30,079	67,418
926	Employee Pensions and Benefits	13	22,410,000	4,876,416	2,388,906	573,696	817,965	990,522	342,873	9,150,003	1,862,271	629,721	463,887	87,399	226,341
927	Franchise Requirements														
928	Regulatory Commission Expenses	16	1,193,000	361,002	164,038	39,369	56,787	43,067	23,860	399,178	74,920	13,720	10,021	2,028	5,011
929	Duplicate Charges-Credit														
930	Miscellaneous General Expenses	12	292,079	104,477	29,617	7,477	10,661	11,683	4,060	96,386	15,948	5,228	3,797	847	1,899
930	Miscellaneous Company Charges	12	6,937,970	2,481,712	703,510	177,612	253,236	277,519	96,438	2,289,530	378,813	124,190	90,194	20,120	45,097
931	Other	12	38,000	13,593	3,853	973	1,387	1,520	528	12,540	2,075	680	494	110	247
	Total Operation		124,513,825	41,333,221	12,785,301	3,196,382	4,557,998	5,070,022	1,769,394	42,849,753	7,446,921	2,449,745	1,785,749	382,069	887,274

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

				Volumetric Costs						Customer Costs					
	Account	Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Maintenance														
932	Maintenance of General Plant	12	4,411,000	1,577,815	447,275	112,922	161,002	176,440	61,313	1,455,630	240,841	78,957	57,343	12,792	28,672
935	Maintenance of General Plant	12	267,000	95,506	27,074	6,835	9,746	10,680	3,711	88,110	14,578	4,779	3,471	774	1,736
	Total Maintenance		4,678,000	1,673,321	474,349	119,757	170,748	187,120	65,024	1,543,740	255,419	83,736	60,814	13,566	30,408
	Total Administrative & General Expenses		**129,191,825**	**43,006,542**	**13,259,650**	**3,316,139**	**4,728,746**	**5,257,142**	**1,834,418**	**44,393,493**	**7,702,340**	**2,533,481**	**1,846,563**	**395,635**	**917,682**
	Total Operation and Maintenance Expenses		**293,505,569**	**102,134,304**	**30,104,404**	**7,501,050**	**10,696,963**	**11,792,211**	**4,104,245**	**98,281,570**	**16,625,001**	**5,450,354**	**3,973,107**	**864,464**	**1,977,908**
DEPRECIATION AND AMORTIZATION EXPENSE															
PRODUCTION PLANT															
305	Manufactured Gas Plant Site Remdiation	2	(23,039)	(3,523)	(2,106)	(650)	(1,599)	(14,116)	(1,046)	-	-	-	-	-	-
325.2	Production Leaseholds	2	33	5	3	1	2	20	1	-	-	-	-	-	-
325.4	Rights-Of-Way	2	18	3	2	1	1	11	1	-	-	-	-	-	-
328	Field Measuring and Regulating Station Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Other Structures	2	-	-	-	-	-	-	-	-	-	-	-	-	-
330	Producing Gas Wells - Well Construction	2	-	-	-	-	-	-	-	-	-	-	-	-	-
331	Producint Gas Wells - Well Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
332	Field Lines	2	948	145	87	27	66	581	43	-	-	-	-	-	-
334	Field Measuring and Regulating Station Equipment	2	383	59	35	11	27	235	17	-	-	-	-	-	-
335	Drilling and Cleaning Equipment	2	16	2	1	-	1	10	1	-	-	-	-	-	-
337	Other Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Production Plant		**(21,641)**	**(3,309)**	**(1,978)**	**(610)**	**(1,502)**	**(13,259)**	**(983)**	**-**	**-**	**-**	**-**	**-**	**-**
STORAGE PLANT															
352.01	**Well Construction**	**2**	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANSMISSION PLANT															
365.2	Rights-Of-Way	4	11,469	5,373	3,507	835	1,217	-	537	-	-	-	-	-	-
366	Structures and Improvements	4	1,122	526	343	82	119	-	53	-	-	-	-	-	-
367	Mains	4	452,433	211,965	138,354	32,937	48,003	-	21,174	-	-	-	-	-	-
369	Measuring and Regulating Staion Equipment	4	90,744	42,514	27,750	6,606	9,628	-	4,247	-	-	-	-	-	-
370	Communication Equipment	4	97,784	45,812	29,902	7,119	10,375	-	4,576	-	-	-	-	-	-
371	Other Equipment	4	1,074	503	328	78	114	-	50	-	-	-	-	-	-
371.1	Testing Equipment	4	4,914	2,302	1,503	358	521	-	230	-	-	-	-	-	-
	Total Transmission Plant		**659,540**	**308,995**	**201,687**	**48,015**	**69,977**	**-**	**30,867**	**-**	**-**	**-**	**-**	**-**	**-**
DISTRIBUTION PLANT															
305	Manufactured Gas Plant Site Remediation	1	-	-	-	-	-	-	-	-	-	-	-	-	-
374.2	Rights of Way	18	45,770	20,230	13,205	3,144	4,582	2,586	2,023	-	-	-	-	-	-
375	Structures And Improvements	18	84,890	37,521	24,491	5,832	8,497	4,796	3,752	-	-	-	-	-	-
376	Mains - Small	4	13,681,072	6,409,582	4,183,672	995,982	1,451,562	-	640,274	-	-	-	-	-	-
	Mains - Large	4	25,153,185	11,784,267	7,691,844	1,831,152	2,668,753	-	1,177,169	-	-	-	-	-	-
	Mains - Direct Assign	DA	2,324,426					2,324,390	36						
378	Measuring & Regulating Equipment - General	18	5,960,845	2,634,693	1,719,704	409,510	596,681	336,788	263,469	-	-	-	-	-	-
379	Measuring & Regulating Equipment - City Gate	18	607,635	268,575	175,303	41,745	60,824	34,331	26,857	-	-	-	-	-	-
380	Services	6C	40,073,393	-	-	-	-	-	-	34,935,984	4,812,814	160,294	100,183	12,022	52,095
381	Meters	6	5,529,933	-	-	-	-	-	-	2,354,645	2,450,313	322,948	241,658	43,686	116,682
382	Meter Installations	6	3,015,930	-	-	-	-	-	-	1,284,183	1,336,359	176,130	131,796	23,826	63,636
383	House Regulators	6A	137,693	-	-	-	-	-	-	121,032	16,661	-	-	-	-
384	House Regulator Installations	6A	486,457	-	-	-	-	-	-	427,596	58,861	-	-	-	-
385	Industrial Measuring & Regulating Equipment	6	825,092	-	-	-	-	-	-	351,324	365,598	48,185	36,057	6,518	17,409
386	Other Property on Customer Premises	6C	23,675	-	-	-	-	-	-	20,640	2,843	95	59	7	31
387	Other Equipment	10	99,425	20,024	13,104	3,092	4,375	6,433	1,889	36,986	11,146	1,074	785	139	378
387.1	Other Equipment	10	4,177	841	551	130	184	270	79	1,554	468	45	33	6	16
	Total Distribution Plant		**98,053,598**	**21,175,733**	**13,821,874**	**3,290,587**	**4,795,458**	**2,709,594**	**2,115,548**	**39,533,944**	**9,055,063**	**708,771**	**510,571**	**86,204**	**250,247**
GENERAL PLANT															
390	Structures And Improvements	12	4,797,233	1,715,970	486,439	122,809	175,099	191,889	66,682	1,583,087	261,929	85,870	62,364	13,912	31,182
391	Office Furniture And Equipment	12	350,467	125,362	35,537	8,972	12,792	14,019	4,871	115,654	19,135	6,273	4,556	1,016	2,278
392	Transportation Equipment	12	5,308,101	1,898,708	538,241	135,887	193,746	212,324	73,783	1,751,673	289,822	95,015	69,005	15,393	34,503
393	Stores Equipment	12	834	298	85	21	30	33	12	275	46	15	11	2	5
394	Tools, Shop And Garage Equipment	12	2,080,239	744,101	210,936	53,254	75,929	83,210	28,915	686,479	113,581	37,236	27,043	6,033	13,522
395	Laboratory Equipment	12	22,097	7,904	2,241	566	807	884	307	7,292	1,206	396	287	64	144
396	Power Operated Equipment	12	446,936	159,869	45,319	11,442	16,313	17,877	6,212	147,489	24,403	8,000	5,810	1,296	2,905
397	Communication Equipment	12	106,929	38,249	10,843	2,737	3,903	4,277	1,486	35,287	5,838	1,914	1,390	310	695
398	Miscellaneous Equipment	12	315,221	112,755	31,963	8,070	11,506	12,609	4,382	104,023	17,211	5,642	4,098	914	2,049
	Total General Plant		**13,428,057**	**4,803,216**	**1,361,604**	**343,758**	**490,125**	**537,122**	**186,650**	**4,431,259**	**733,171**	**240,361**	**174,564**	**38,940**	**87,283**
COMMON PLANT ALLOCATED @ 88.43%															
390.2	Structures and Improvements	12	859,246	307,352	87,128	21,997	31,362	34,370	11,944	283,551	46,915	15,380	11,170	2,492	5,585
391	Office Furniture and Equipment	12	449,325	160,724	45,562	11,503	16,400	17,973	6,246	148,277	24,533	8,043	5,841	1,303	2,921
392.1	Transportation Equipment	12	-	-	-	-	-	-	-	-	-	-	-	-	-
398	Miscellaneous Equipment	12	2,858	1,022	290	73	104	114	40	943	156	51	37	8	19
	Total Common Plant		**1,311,428**	**469,098**	**132,980**	**33,573**	**47,866**	**52,457**	**18,230**	**432,771**	**71,604**	**23,474**	**17,048**	**3,803**	**8,525**
INFORMATION SERVICES (IS) ALLOCATED @ 91.68%															
391	Office Furniture and Equipment	12	13,161,549	4,707,886	1,334,581	336,936	480,397	526,462	182,946	4,343,311	718,621	235,592	171,100	38,168	85,550
391.1	Office Furniture and Equip. - New CIS Software	7	4,655,090	-	-	-	-	-	-	4,164,909	473,888	9,310	4,190	466	2,328
391.4	Office Furniture and Equip. - New CIS Software	12	2,705,627	967,803	274,351	69,264	98,755	108,225	37,608	892,857	147,727	48,431	35,173	7,846	17,587
	Total Information Services		**20,522,266**	**5,675,689**	**1,608,932**	**406,200**	**579,152**	**634,687**	**220,554**	**9,401,077**	**1,340,236**	**293,333**	**210,463**	**46,480**	**105,465**

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

			Volumetric Costs						Customer Costs					
Account	Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Less:														
Amount Charged to Clearing Accounts	12	(8,371,000)	(2,994,307)	(848,819)	(214,298)	(305,542)	(334,840)	(116,357)	(2,762,430)	(457,057)	(149,841)	(108,823)	(24,276)	(54,412)
390.1 Reading Service Center Alloc. to Electric Div. @ 8.32%	12	(10,551)	(3,774)	(1,070)	(270)	(385)	(422)	(147)	(3,482)	(576)	(189)	(137)	(31)	(69)
390.1 Empire Building Alloc. To Electric Div. @ 13.07%	12	(35,345)	(12,643)	(3,584)	(905)	(1,290)	(1,414)	(491)	(11,664)	(1,930)	(633)	(459)	(103)	(230)
Total Depreciation & Amortization Expense		**125,536,352**	**29,418,698**	**16,271,626**	**3,906,050**	**5,673,859**	**3,583,925**	**2,453,871**	**51,021,475**	**10,740,511**	**1,115,276**	**803,227**	**151,017**	**396,809**
TAXES OTHER THAN INCOME TAXES														
408.10 Capital Stock	15	-	-	-	-	-	-	-	-	-	-	-	-	-
408.10 County and Municipal Taxes	16	1,868,000	565,257	256,850	61,644	88,917	67,435	37,360	625,033	117,310	21,482	15,691	3,176	7,846
408.10 Payroll Related Tax	13	6,926,300	1,507,163	738,344	177,313	252,810	306,142	105,972	2,828,008	575,576	194,629	143,374	27,013	69,956
408.10 Public Utility Assessment	16	4,042,000	1,223,109	555,775	133,386	192,399	145,916	80,840	1,352,453	253,838	46,483	33,953	6,871	16,976
408.10 Public Utility Reality Tax	15	822,000	237,887	142,781	33,455	48,662	28,852	21,290	250,052	48,498	4,685	3,452	658	1,726
408.10 Miscellaneous Taxes	16	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Taxes Other Than Income		**13,658,300**	**3,533,416**	**1,693,750**	**405,798**	**582,788**	**548,345**	**245,462**	**5,055,546**	**995,222**	**267,279**	**196,470**	**37,718**	**96,504**
Total Operating Expenses		**432,700,221**	**135,086,418**	**48,069,780**	**11,812,898**	**16,953,610**	**15,924,481**	**6,803,578**	**154,358,591**	**28,360,734**	**6,832,909**	**4,972,804**	**1,053,199**	**2,471,221**
INCOME TAXES	15	63,347,000	18,332,622	11,003,374	2,578,223	3,750,142	2,223,480	1,640,687	19,270,157	3,737,473	361,078	266,057	50,678	133,029
OPERATING INCOME AVAILABLE FOR RETURN	15	252,254,645	73,002,494	43,816,632	10,266,764	14,933,475	8,854,138	6,533,395	76,735,863	14,883,024	1,437,851	1,059,470	201,804	529,735
TOTAL COST OF SERVICE		**748,301,866**	**226,421,534**	**102,889,786**	**24,657,885**	**35,637,227**	**27,002,099**	**14,977,660**	**250,364,611**	**46,981,231**	**8,631,838**	**6,298,331**	**1,305,681**	**3,133,985**
Less: Other Revenues														
Reconnection Charges	6C	-	-	-	-	-	-	-	-	-	-	-	-	-
Rent From Gas Property	12	2,686,000	960,782	272,360	68,762	98,039	107,440	37,335	886,380	146,656	48,079	34,918	7,789	17,459
Forfieted Discounts/Penalties	20	5,603,000	-	-	-	-	-	-	2,654,096	2,163,576	275,550	302,909	104,541	102,328
Other Miscellaneous Revenues	16	1,998,000	604,595	274,725	65,934	95,105	72,128	39,960	668,531	125,474	22,977	16,783	3,397	8,392
Subtotal		10,287,000	1,565,377	547,085	134,696	193,144	179,568	77,295	4,209,007	2,435,706	346,606	354,610	115,727	128,179
TOTAL COST OF SERVICE RELATED TO TARIFF SALES AND TRANSPORTATION		**$ 738,014,866**	**$ 224,856,157**	**$ 102,342,701**	**$ 24,523,189**	**$ 35,444,083**	**$ 26,822,531**	**$ 14,900,365**	**$ 246,155,604**	**$ 44,545,525**	**$ 8,285,232**	**$ 5,943,721**	**$ 1,189,954**	**$ 3,005,806**

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTORS 1 and 1A. ALLOCATION OF COSTS WHICH VARY DIRECTLY WITH PGC AND CHOICE SALES.

Factors are based on the pro forma average daily PGC sales volumes for each service classification.

Service Classification	Pro Forma Average Daily PGC Volumes (Mcf)	Allocation Factor 1	PGC and Choice Volumes (Mcf)	Allocation Factor 1A
(1)	(2)	(3)		
Volumetric Costs				
Rate R	124,315	0.7176	142,485	0.6257
Rate N	48,925	0.2824	85,232	0.3743
Rate DS		-		
Rate LFD		-		
Rate XD	-	-		
Interruptible	-	-		
Total	173,240	1.0000	227,717	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTORS 2 . ALLOCATION OF COMPRESSOR STATION FUEL.

Factors are based on the pro forma average daily throughput volumes for each service classification.

Service Classification	Pro Forma Average Daily Throughput Volumes (Mcf)	Allocation Factor 2
(1)	(2)	(3)
Volumetric Costs		
Rate R	142,485	0.1529
Rate N	85,232	0.0914
Rate DS	26,335	0.0282
Rate LFD	64,765	0.0694
Rate XD Firm	571,442	0.6127
Interruptible	42,334	0.0454
Total	932,593	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTORS 3 and 3A. CALCULATION OF MAXIMUM DAY EXTRA DEMAND FACTORS.

Factors are based on the maximum day extra demand throughput for each classification.

Service Classification	Pro Forma Average Daily Throughput Volumes (Mcf)	Peak Day Capacity (Mcf)	Extra Capacity (Mcf)	Allocation Factor 3	Allocation Factor 3A
(1)	(2)	(3)	(4)=(3)-(2)	(5)	(6)
Volumetric Costs					
Rate R	142,485	649,604	507,119	0.4141	0.5203
Rate N	85,232	431,709	346,477	0.2830	0.3554
Rate DS	26,335	96,848	70,513	0.0576	0.0723
Rate LFD	64,765	115,419	50,654	0.0414	0.0520
Subtotal	318,817	1,293,580	974,763	0.7961	1.0000
Rate XD Firm	571,442	821,122	249,680	0.2039	-
Total	890,259	2,114,702	1,224,443	1.0000	1.0000
Firm Service Load Factor	0.4210		0.5790		

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 4. ALLOCATION OF COSTS ASSOCIATED WITH TRANSMISSION AND LARGE DISTRIBUTION MAINS.

Factors are based on the weighting of the factors derived from average daily throughput volumes volumes and from maximum day extra capacity demand for each service classification, as follows:

	Average Daily Throughput			Maximum Day Extra Demand		
Service Classification	MCF/Day	Allocation Factor	Weighted Factor*	Allocation Factor 3A	Weighted Factor*	Allocation Factor 4
(1)	(2)	(3)	(4)=(3)x 0.4210	(5)	(6)=(5)x 0.5790	(7)=(4)+(6)
Volumetric Costs						
Rate R	142,485	0.3973	0.1673	0.5203	0.3012	0.4685
Rate N	85,232	0.2376	0.1000	0.3554	0.2058	0.3058
Rate DS	26,335	0.0734	0.0309	0.0723	0.0419	0.0728
Rate LFD	64,765	0.1806	0.0760	0.0520	0.0301	0.1061
Rate XD Firm		-	-	-	-	-
Interruptible**	39,847	0.1111	0.0468		-	0.0468
Total	358,664	1.0000	0.4210	1.0000	0.5790	1.0000

* The weighting of the factors is based on the system load factor for firm service. See Factor 3.
** Excludes XD-I volumes for customers who are 100% interruptible.

FACTOR 4A. ALLOCATION OF COSTS ASSOCIATED WITH LOAD DISPATCHING AND M&R STATION EQUIPMENT.

Factors are based on the weighting of the factors derived from average daily throughput volumes and from maximum day extra capacity demand for each service classification, as follows:

		Average Daily Throughput		Maximum Day Extra Demand		
Service Classification	Throughput	Allocation Factor 2	Weighted Factor	Allocation Factor 3	Weighted Factor	Allocation Factor
(1)	(2)	(3)	(4)=(3)x 0.4410	(5)	(6)=(5)x 0.5590	(7)=(4)+(6)
Volumetric						
Rate R	142,485	0.1529	0.0675	0.4141	0.2315	0.2990
Rate N	85,232	0.0914	0.0403	0.2830	0.1582	0.1985
Rate DS	26,335	0.0282	0.0124	0.0576	0.0322	0.0446
Rate LFD	64,765	0.0694	0.0306	0.0414	0.0231	0.0537
Rate XD-Firm	571,442	0.6127	0.2702	0.2039	0.1140	0.3842
Interruptible	42,334	0.0454	0.0200	-	-	0.0200
Total	932,593	1.0000	0.4410	1.0000	0.5590	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 5. NOT USED IN THIS ALLOCATION.

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 6. ALLOCATION OF COSTS ASSOCIATED WITH ACCOUNTS 381 and 385.

Factors are based on the cost of meters by class included in Accounts 381 and 385, Meters and M&R Equipment.

Service Classification	Meter Costs SDR-COS-7	Allocation Factor
(1)		(3)
Customer Costs		
Rate R	$ 75,859,636	0.4258
Rate N	78,928,022	0.4431
Rate DS	10,405,903	0.0584
Rate LFD	7,783,898	0.0437
Rate XD-Firm	1,404,538	0.0079
Interruptible	3,754,266	0.0211
Total	$ 178,136,264	1.0000

FACTOR 6A. ALLOCATION OF COSTS ASSOCIATED WITH HOUSE REGULATORS

Factors are based on the number of weighted house regulators for customers served.

Service Classification	Number of Regulators	Factor	Weighted Regulators	Allocation Factor
(1)	(2)	(3)	(4)	(5)
Customer				
Rate R	616,132	1.00	616,132	0.8790
Rate N	70,125	1.21	84,851	0.1210
Total	686,257		700,983	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 6B. ALLOCATION OF COSTS ASSOCIATED WITH INDUSTRIAL MEASURING AND REGULATING EQUIPMENT.

Factors are based on the cost of Meters and M&R equipment by class included in Accounts 381 and 385.

Service Classification	Cost of Meters & M&R Equipment	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate DS	$ 10,405,903	0.4456
Rate LFD	7,783,898	0.3334
Rate XD - Firm	1,404,538	0.0602
Interruptible	3,754,266	0.1608
Total	$ 23,348,605	1.0000

FACTOR 6C. ALLOCATION OF COSTS ASSOCIATED WITH SERVICES.

Factors are based on the cost of services by class included in Account 380, Service Lines.

Service Classification	Cost of Service Lines SDR-COS-6	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 1,141,965,038	0.8718
Rate N	157,264,701	0.1201
Rate DS	5,215,208	0.0040
Rate LFD	3,245,947	0.0025
Rate XD - Firm	402,109	0.0003
Interruptible	1,670,210	0.0013
Total	$ 1,309,763,212	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 7. ALLOCATION OF COSTS ASSOCIATED WITH CUSTOMER ACCOUNTING AND METER READING.

Factors are based on the number of customers for each classification, as follows.

Service Classification	Number of Customers	Allocation Factor 7	Allocation Factor 7A
(1)	(2)	(3)	(4)
Customer Costs			
Rate R	616,132	0.8947	
Rate N	70,125	0.1018	
Rate DS	1,392	0.0020	0.5769
Rate LFD	602	0.0009	0.2495
Rate XD Firm	56	0.0001	0.0232
Interruptible	363	0.0005	0.1504
Total	688,670	1.0000	1.0000

FACTOR 8. ALLOCATION OF COSTS ASSOCIATED WITH SALES EXPENSES.

Factors are based on the number of Rate R and Rate N customers.

Service Classification	Number of Customers	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	616,132	0.8978
Rate N	70,125	0.1022
Total	686,257	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 9 (DA). ALLOCATION OF CUSTOMER ASSISTANCE EXPENSES.

These costs are directly assigned to the Residential Classification.

Service Classification	Allocation Factor
(1)	(3)
Customer Costs	
Rate R	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 10. ALLOCATION OF DISTRIBUTION OPERATION OTHER EXPENSES AND RENT.

Factors are based on distribution operation expenses other than those being allocated.

Service Classification	Operation Expenses	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 7,641,985	0.2014
Rate N	5,001,491	0.1318
Rate DS	1,178,822	0.0311
Rate LFD	1,669,276	0.0440
Rate XD Firm	2,453,803	0.0647
Interruptible	720,011	0.0190
Customer Costs		
Rate R	14,113,617	0.3720
Rate N	4,252,801	0.1121
Rate DS	409,140	0.0108
Rate LFD	299,616	0.0079
Rate XD Firm	52,149	0.0014
Interruptible	145,896	0.0038
Total	$ 37,938,607	1.0000

FACTOR 11. ALLOCATION OF DISTRIBUTION MAINTENANCE OTHER EXPENSES.

Factors are based on distribution maintenance expenses other than those being allocated.

Service Classification	Maintenance Expenses	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 13,625,330	0.3577
Rate N	8,902,328	0.2337
Rate DS	2,109,995	0.0554
Rate LFD	3,038,765	0.0798
Rate XD Firm	2,808,455	0.0737
Interruptible	1,327,745	0.0349
Customer Costs		
Rate R	1,348,688	0.0354
Rate N	185,797	0.0049
Rate DS	2,115,156	0.0555
Rate LFD	1,581,808	0.0415
Rate XD Firm	285,383	0.0075
Interruptible	763,057	0.0200
Total	$ 38,092,507	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 12. ALLOCATION OF ADMINISTRATIVE AND GENERAL EXPENSES.

Factors are based on the allocation of operation and maintenance expenses.

Service Classification	Operation & Maintenance Expenses	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 58,412,076	0.3577
Rate N	16,563,107	0.1014
Rate DS	4,184,911	0.0256
Rate LFD	5,968,217	0.0365
Rate XD Firm	6,535,069	0.0400
Interruptible	2,269,827	0.0139
Customer Costs		
Rate R	53,888,077	0.3300
Rate N	8,922,661	0.0546
Rate DS	2,916,873	0.0179
Rate LFD	2,126,544	0.0130
Rate XD Firm	468,829	0.0029
Interruptible	1,060,226	0.0065
Total	$ 163,316,416	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 13. ALLOCATION OF LABOR RELATED TAXES AND BENEFITS.

Factors are based on the allocation of total operation and maintenance direct labor expense to service classifications as shown on the following page.

Service Classification	Total Labor Expense	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 17,893,133	0.2176
Rate N	8,758,218	0.1066
Rate DS	2,105,694	0.0256
Rate LFD	3,001,923	0.0365
Rate XD Firm	3,629,955	0.0442
Interruptible	1,258,993	0.0153
Customer Costs		
Rate R	33,557,903	0.4083
Rate N	6,831,162	0.0831
Rate DS	2,307,401	0.0281
Rate LFD	1,703,937	0.0207
Rate XD Firm	317,757	0.0039
Interruptible	828,677	0.0101
Total	$ 82,194,753	1.0000

FACTOR 14. ALLOCATION OF ORGANIZATION, FRANCHISES AND CONSENTS, MISCELLANEOUS INTANGIBLE PLANT AND OTHER RATE BASE ELEMENTS.

Factors are based on the allocation of the original cost less depreciation excluding the items being allocated, as follows:

Service Classification	Original Cost Less Depreciation	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$1,098,567,065	0.2892
Rate N	659,638,747	0.1738
Rate DS	154,472,738	0.0407
Rate LFD	224,802,620	0.0592
Rate XD Firm	133,264,013	0.0351
Interruptible	98,294,314	0.0259
Customer Costs		
Rate R	1,154,767,671	0.3042
Rate N	223,937,492	0.0590
Rate DS	21,838,287	0.0058
Rate LFD	15,790,971	0.0042
Rate XD Firm	3,018,638	0.0008
Interruptible	7,966,620	0.0021
Total	$3,796,359,176	1.0000

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

				Volumetric Costs						Customer Costs					
Account		Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
DIRECT LABOR EXPENSE															
725 - 736	Total Gas Fuels Expenses	1	0	-	-	-	-	-	-	-	-	-	-	-	-
750-760	Total Production & Gathering Operation Expenses	1	0	-	-	-	-	-	-	-	-	-	-	-	-
761 - 769	Total Gas Raw Materials Expenses	1	-	-	-	-	-	-	-	-	-	-	-	-	-
813	Other Gas Supply Expenses	1	-	-	-	-	-	-	-	-	-	-	-	-	-
840	Storage	1A	-	-	-	-	-	-	-	-	-	-	-	-	-
850 - 860	Total Transmission Operation Expenses	4	-	-	-	-	-	-	-	-	-	-	-	-	-
861 - 867	Total Transmission Maintenance Expenses	4	-	-	-	-	-	-	-	-	-	-	-	-	-
870	Operation Supervision and Engineering	10	5,077,635	1,022,636	669,232	157,914	223,416	328,523	96,475	1,888,880	569,203	54,838	40,113	7,109	19,295
871	Distribution Load Dispatching	4A	2,030	607	403	91	109	780	41	-	-	-	-	-	-
874	Mains And Services Expenses														
	Mains - Small	4	2,887,365	1,352,731	882,956	210,200	306,349	-	135,129	-	-	-	-	-	-
	Mains - Large	17	5,308,532	2,277,360	1,485,858	353,548	515,458	449,102	227,205	-	-	-	-	-	-
	Services	6C	7,586,453	-	-	-	-	-	-	6,613,870	911,133	30,346	18,966	2,276	9,862
875	M & R Station Expenses -General	4A	2,618,551	782,947	519,782	116,787	140,616	1,006,047	52,371	-	-	-	-	-	-
876	Measuring and Regulating Station Expenses-Industrial	6B	13,194	-	-	-	-	-	-	-	-	5,879	4,399	794	2,122
877	Measuring and Regulating Station Expenses-City Gate	4A	113,674	33,989	22,564	5,070	6,104	43,674	2,273	-	-	-	-	-	-
878	Meter And House Regulator Expenses	6	2,795,151	-	-	-	-	-	-	1,190,175	1,238,531	163,237	122,148	22,082	58,978
879	Customer Installation Expenses	6	2,625,655	-	-	-	-	-	-	1,118,004	1,163,428	153,338	114,741	20,743	55,401
880	Other Expenses	10	1,089,033	219,331	143,535	33,869	47,917	70,460	20,692	405,120	122,081	11,762	8,603	1,525	4,138
881	Rent	10	-	-	-	-	-	-	-	-	-	-	-	-	-
885	Supervision - Engineering and Labor	11	496,307	177,529	115,987	27,495	39,605	36,578	17,321	17,569	2,432	27,545	20,597	3,722	9,926
886	Structures & Improvements	18	-	-	-	-	-	-	-	-	-	-	-	-	-
887	Mains - Small	4	2,970,949	1,391,890	908,516	216,285	315,218	-	139,040	-	-	-	-	-	-
	Mains - Large	17	5,462,205	2,343,286	1,528,871	363,783	530,380	462,103	233,782	-	-	-	-	-	-
889	M & R Equip - General	4A	834,282	249,450	165,605	37,209	44,801	320,531	16,686	-	-	-	-	-	-
890	M & R Equip - Ind	6B	3,183,873	-	-	-	-	-	-	-	-	1,418,734	1,061,503	191,669	511,967
891	M & R Equip - CG Check Station	4A	12,179	3,642	2,418	543	654	4,679	244	-	-	-	-	-	-
892	Services	6C	1,015	-	-	-	-	-	-	885	122	4	3	-	1
893	Meters & House Regulators	6	-	-	-	-	-	-	-	-	-	-	-	-	-
895	Other Equipment	11	256,780	91,850	60,009	14,226	20,491	18,925	8,962	9,090	1,258	14,251	10,656	1,926	5,136
894	Other Equipment	11	-	-	-	-	-	-	-	-	-	-	-	-	-
901	Supervision	7	557,203	-	-	-	-	-	-	498,530	56,723	1,114	501	56	279
902	Meter Reading Expenses	7	2,112,095	-	-	-	-	-	-	1,889,691	215,011	4,224	1,901	211	1,056
903	Customer Records & Coll Expenses	7	10,122,018	-	-	-	-	-	-	9,056,170	1,030,421	20,244	9,110	1,012	5,061
905	Miscellaneous Cust Accts Expenses	7	1,904,031	-	-	-	-	-	-	1,703,537	193,830	3,808	1,714	190	952
907	Supervision	7	163,406	-	-	-	-	-	-	146,199	16,635	327	147	16	82
908	Customer Assistance Expenses	9	833,267	-	-	-	-	-	-	833,267	-	-	-	-	-
910	Miscellaneous Customer Service & Info. Exp.	7	60,897	-	-	-	-	-	-	54,485	6,199	122	55	6	30
911	Supervision	8	364,364	-	-	-	-	-	-	327,126	37,238	-	-	-	-
912	Demonstrating And Selling Expenses	8	528,785	-	-	-	-	-	-	474,743	54,042	-	-	-	-
920	Administrative & General Salaries	12	19,758,774	7,067,713	2,003,540	505,825	721,195	790,351	274,647	6,520,395	1,078,829	353,682	256,864	57,300	128,432
921	Office Supplies And Expenses	12	-	-	-	-	-	-	-	-	-	-	-	-	-
922	Administrative Expenses Transferred-Credit	12	-	-	-	-	-	-	-	-	-	-	-	-	-
923	Outside Service Employed	12	1,015	363	103	26	37	41	14	335	55	18	13	3	7
924	Property Insurance	12	-	-	-	-	-	-	-	-	-	-	-	-	-
925	Injuries and Damages	12	1,017,987	364,134	103,224	26,060	37,157	40,719	14,150	335,936	55,582	18,222	13,234	2,952	6,617
927	Franchise Requirements	12	-	-	-	-	-	-	-	-	-	-	-	-	-
928	Regulatory Commission Expenses	12	-	-	-	-	-	-	-	-	-	-	-	-	-
929	Duplicate Charges-Credit	12	-	-	-	-	-	-	-	-	-	-	-	-	-
930	Miscellaneous General Expenses	12	277,079	99,111	28,096	7,093	10,113	11,083	3,851	91,436	15,129	4,960	3,602	804	1,801
930	Miscellaneous Intercompany Charges	12	(2,030)	(726)	(206)	(52)	(74)	(81)	(28)	(670)	(111)	(36)	(26)	(6)	(13)
932	Maintenance of General Plant	12	1,161,000	415,290	117,725	29,722	42,377	46,440	16,138	383,130	63,391	20,782	15,093	3,367	7,547
	Total Direct Labor Expense		$ 82,194,754	$ 17,893,133	$ 8,758,218	$ 2,105,694	$ 3,001,923	$ 3,629,955	$ 1,258,993	$ 33,557,903	$ 6,831,162	$ 2,307,401	$ 1,703,937	$ 317,757	$ 828,677

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 15. ALLOCATION OF RETURN AND TAXES.

Factors are based on the result of allocating the original cost measure of value, as presented on the following pages.

Service Classification	Original Cost Less Depreciation	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 917,142,710	0.2894
Rate N	550,606,371	0.1737
Rate DS	128,939,874	0.0407
Rate LFD	187,663,895	0.0592
Rate XD Firm	111,244,603	0.0351
Interruptible	82,046,084	0.0259
Customer Costs		
Rate R	963,932,480	0.3042
Rate N	186,924,574	0.0590
Rate DS	18,199,962	0.0057
Rate LFD	13,156,321	0.0042
Rate XD Firm	2,516,808	0.0008
Interruptible	6,649,297	0.0021
Total	$ 3,169,022,979	1.0000

FACTOR 16. ALLOCATION OF REGULATORY COMMISSION EXPENSES, ASSESSMENTS AND OTHER REVENUES.

Factors are based on the allocated cost of service excluding those items being allocated.

Service Classification	Total Cost of Service	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 224,272,166	0.3026
Rate N	101,913,123	0.1375
Rate DS	24,423,486	0.0330
Rate LFD	35,299,124	0.0476
Rate XD Firm	26,745,681	0.0361
Interruptible	14,835,600	0.0200
Customer Costs		
Rate R	247,987,947	0.3346
Rate N	46,535,163	0.0628
Rate DS	8,550,153	0.0115
Rate LFD	6,238,666	0.0084
Rate XD Firm	1,293,606	0.0017
Interruptible	3,104,152	0.0042
Total	$ 741,198,866	1.0000

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

				Volumetric Costs						Customer Costs					
Account		Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
RATE BASE															
PRODUCTION PLANT															
305	Manufactured Gas Plant Site Remdiation	2	(69,118)	(10,568)	(6,317)	(1,949)	(4,797)	(42,349)	(3,138)	-	-	-	-	-	-
325.1	Producing Lands	2	13,029	1,992	1,191	367	904	7,983	592	-	-	-	-	-	-
325.2	Production Leaseholds	2	965	148	88	27	67	591	44	-	-	-	-	-	-
325.4	Rights-Of-Way	2	560	86	51	16	39	343	25	-	-	-	-	-	-
325.5	Other Lands	2	1,134	173	104	32	79	695	51	-	-	-	-	-	-
328	Field Measuring and Regulating Station Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Other Structures	2	2	-	-	-	-	1	-	-	-	-	-	-	-
330	Producing Gas Wells - Well Construction	2	-	-	-	-	-	-	-	-	-	-	-	-	-
331	Producing Gas Wells - Well Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
332	Field Lines	2	23,897	3,654	2,184	674	1,658	14,642	1,085	-	-	-	-	-	-
334	Field Measuring and Regulating Station Equipment	2	4,352	665	398	123	302	2,666	198	-	-	-	-	-	-
335	Drilling and Cleaning Equipment	2	101	15	9	3	7	62	5	-	-	-	-	-	-
337	Other Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Production Plant		(25,078)	(3,835)	(2,292)	(707)	(1,741)	(15,366)	(1,138)	-	-	-	-	-	-
STORAGE PLANT															
352.01	Well Construction	2	35,934	5,494	3,284	1,013	2,494	22,017	1,631	-	-	-	-	-	-
TRANSMISSION PLANT															
365	Land	4	47,323	22,171	14,471	3,445	5,021	-	2,215	-	-	-	-	-	-
365.2	Rights-Of-Way	4	319,697	149,778	97,763	23,274	33,920	-	14,962	-	-	-	-	-	-
366	Structures and Improvements	4	14,665	6,871	4,485	1,068	1,556	-	686	-	-	-	-	-	-
367	Mains	4	16,728,788	7,837,437	5,115,663	1,217,856	1,774,924	-	782,907	-	-	-	-	-	-
369	Measuring and Regulating Staion Equipment	4	2,093,133	980,633	640,080	152,380	222,081	-	97,959	-	-	-	-	-	-
370	Communication Equipment	4	1,241,718	581,745	379,717	90,397	131,746	-	58,112	-	-	-	-	-	-
371	Other Equipment	4	9,919	4,647	3,033	722	1,052	-	464	-	-	-	-	-	-
371.1	Testing Equipment	4	52,388	24,544	16,020	3,814	5,558	-	2,452	-	-	-	-	-	-
	Total Transmission Plant		20,507,631	9,607,826	6,271,232	1,492,956	2,175,858	-	959,757	-	-	-	-	-	-
DISTRIBUTION PLANT															
374	Land	18	849,347	375,411	245,037	58,350	85,020	47,988	37,541	-	-	-	-	-	-
374	Land Rights of Way	18	7,305,824	3,229,174	2,107,730	501,910	731,313	412,779	322,917	-	-	-	-	-	-
374	Rights of Way	4	2,117,511	992,054	647,535	154,155	224,668	-	99,100	-	-	-	-	-	-
375	Structures And Improvements	18	2,211,379	977,430	637,983	151,922	221,359	124,943	97,743	-	-	-	-	-	-
376	Mains - Small	4	627,708,395	294,081,383	191,953,227	45,697,171	66,599,861	-	29,376,753	-	-	-	-	-	-
	Mains - Large	4	1,154,066,353	540,680,086	352,913,491	84,016,030	122,446,440	-	54,010,305	-	-	-	-	-	-
	Mains - Direct Assign	DA	106,648,197					106,646,558	1,639						
378	Measuring & Regulating Equipment - General	18	160,502,424	70,942,071	46,304,949	11,026,517	16,066,293	9,068,387	7,094,207	-	-	-	-	-	-
379	Measuring & Regulating Equipment - SCADA	18		-	-	-	-	-	-	-	-	-	-	-	-
379	Measuring & Regulating Equipment - City Gate	18	16,602,462	7,338,288	4,789,810	1,140,589	1,661,906	938,039	733,829	-	-	-	-	-	-
380	Services	6C	1,027,231,351	-	-	-	-	-	-	895,540,292	123,370,485	4,108,925	2,568,078	308,169	1,335,401
381	Meters	6	105,716,315	-	-	-	-	-	-	45,014,007	46,842,899	6,173,833	4,619,803	835,159	2,230,614
382	Meter Installations	6	70,230,279	-	-	-	-	-	-	29,904,053	31,119,037	4,101,448	3,069,063	554,819	1,481,859
383	House Regulators	6A	3,612,616	-	-	-	-	-	-	3,175,489	437,127	-	-	-	-
384	House Regulator Installations	6A	9,602,363	-	-	-	-	-	-	8,440,477	1,161,886	-	-	-	-
385	Industrial Measuring & Regulating Equipment	6	21,540,899	-	-	-	-	-	-	9,172,115	9,544,772	1,257,989	941,337	170,173	454,513
386	Other Property on Customer Premises	6C	427,942	-	-	-	-	-	-	373,080	51,396	1,712	1,070	128	556
387	Other Equipment	10	1,836,670	369,905	242,073	57,120	80,813	118,833	34,897	683,241	205,891	19,836	14,510	2,571	6,979
387	Other Equipment - Graphic Data Base	10	17,592	3,543	2,319	547	774	1,138	334	6,544	1,972	190	139	25	67
	Total Distribution Plant		3,318,227,919	918,989,345	599,844,154	142,804,311	208,118,447	117,358,665	91,809,265	992,309,298	212,735,465	15,663,933	11,214,000	1,871,044	5,509,989
GENERAL PLANT															
389	Land and Land Rights	12	10,370,785	3,709,630	1,051,598	265,492	378,534	414,831	144,154	3,422,359	566,245	185,637	134,820	30,075	67,410
390	Structures And Improvements	12	87,164,154	31,178,618	8,838,445	2,231,402	3,181,492	3,486,566	1,211,582	28,764,171	4,759,163	1,560,238	1,133,134	252,776	566,567
391	Office Furniture And Equipment	12	4,091,487	1,463,525	414,877	104,742	149,339	163,659	56,872	1,350,191	223,395	73,238	53,189	11,865	26,595
392	Transportation Equipment	12	37,116,223	13,276,473	3,763,585	950,175	1,354,742	1,484,649	515,915	12,248,354	2,026,546	664,380	482,511	107,637	241,255
393	Stores Equipment	12	10,407	3,723	1,055	266	380	416	145	3,434	568	186	135	30	68
394	Tools, Shop And Garage Equipment	12	26,008,960	9,303,405	2,637,309	665,829	949,327	1,040,358	361,525	8,582,957	1,420,089	465,560	338,116	75,426	169,058
393	Laboratory Equipment	12	303,522	108,570	30,777	7,770	11,079	12,141	4,219	100,162	16,572	5,433	3,946	880	1,973
396	Power Operated Equipment	12	3,682,716	1,317,308	373,427	94,278	134,419	147,309	51,190	1,215,296	201,076	65,921	47,875	10,680	23,938
397	Communication Equipment	12	428,059	153,117	43,405	10,958	15,624	17,122	5,950	141,259	23,372	7,662	5,565	1,241	2,782
398	Miscellaneous Equipment	12	1,155,077	413,171	117,125	29,570	42,160	46,203	16,056	381,175	63,067	20,676	15,016	3,350	7,508
	Total General Plant		170,331,390	60,927,540	17,271,603	4,360,482	6,217,096	6,813,254	2,367,608	56,209,358	9,300,093	3,048,931	2,214,307	493,960	1,107,154
	Total Plant		3,509,077,796	989,526,370	623,387,981	148,658,055	216,512,154	124,178,570	95,137,123	1,048,518,656	222,035,558	18,712,864	13,428,307	2,365,004	6,617,143

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

			Volumetric Costs						Customer Costs					
Account	Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
COMMON PLANT ALLOCATED @ 88.97%														
301 Organization	14	123,636	35,756	21,488	5,032	7,319	4,340	3,202	37,610	7,295	717	519	99	260
389.1 Land and Land Rights	12	6,180,842	2,210,887	626,737	158,230	225,601	247,234	85,914	2,039,678	337,474	110,637	80,351	17,924	40,175
390.1 Reading Service Center	12	3,662,434	1,310,052	371,371	93,758	133,679	146,497	50,908	1,208,603	199,969	65,558	47,612	10,621	23,806
390.2 Structures and Improvements	12	27,482,527	9,830,500	2,786,728	703,553	1,003,112	1,099,301	382,007	9,069,234	1,500,546	491,937	357,273	79,699	178,636
391 Office Furniture and Equipment	12	3,324,746	1,189,262	337,129	85,113	121,353	132,990	46,214	1,097,166	181,531	59,513	43,222	9,642	21,611
392.1 Transportation Equipment	12	-	-	-	-	-	-	-	-	-	-	-	-	-
398 Miscellaneous Equipment	12	18,573	6,644	1,883	475	678	743	258	6,129	1,014	332	241	54	121
Total Common Plant		40,792,758	14,583,101	4,145,336	1,046,161	1,491,742	1,631,105	568,503	13,458,420	2,227,829	728,694	529,218	118,039	264,609
INFORMATION SERVICES (IS) ALLOCATED @ 91.68%														
391 Office Furniture and Equipment	12	2,279,539	815,391	231,145	58,356	83,203	91,182	31,686	752,248	124,463	40,804	29,634	6,611	14,817
391.1 Office Furniture and Equip. - CIS	7	40,732,041	-	-	-	-	-	-	36,442,957	4,146,522	81,464	36,659	4,073	20,366
391.2 Office Furniture and Equip. - System Development Cost	12	90,319,674	32,307,347	9,158,415	2,312,184	3,296,668	3,612,787	1,255,443	29,805,492	4,931,454	1,616,722	1,174,156	261,927	587,078
391.4 Office Furniture and Equip. - System Development Cost	12	39,231,589	14,033,139	3,978,083	1,004,329	1,431,953	1,569,264	545,319	12,946,424	2,142,045	702,245	510,011	113,772	255,005
Total Information Services		172,562,843	47,155,877	13,367,643	3,374,869	4,811,824	5,273,233	1,832,448	79,947,121	11,344,484	2,441,235	1,750,460	386,383	877,266
INTANGIBLE PLANT														
301 Organization	14	166,478	48,145	28,934	6,776	9,855	5,843	4,312	50,643	9,822	966	699	133	350
302 Franchises And Consents	14	193,597	55,988	33,647	7,879	11,461	6,795	5,014	58,892	11,422	1,123	813	155	407
303 Miscellaneous Intangible Plant	14	289,868	83,830	50,379	11,798	17,160	10,174	7,508	88,178	17,102	1,681	1,217	232	609
304 Land and Land Rights	14	381,652	110,374	66,331	15,533	22,594	13,396	9,885	116,099	22,517	2,214	1,603	305	801
305 Manufactured Gas Plant Remediation	1		-	-	-	-	-	-	-	-	-	-	-	-
Total Nondepreciable Plant		1,031,595	298,337	179,291	41,986	61,070	36,208	26,719	313,812	60,863	5,984	4,332	825	2,167
Total Utility Plant in Service		3,723,464,991	1,051,563,685	641,080,251	153,121,071	222,876,790	131,119,116	97,564,793	1,142,238,009	235,668,734	21,888,777	15,712,317	2,870,251	7,761,185
OTHER RATE BASE ELEMENTS														
Gas Storage Inventory	1A	17,813,000	11,145,594	6,667,406	-	-	-	-	-	-	-	-	-	-
Cash Working Capital	12	38,947,696	13,931,591	3,949,296	997,061	1,421,591	1,557,908	541,373	12,852,740	2,126,544	697,164	506,320	112,948	253,160
Cash Working Capital - Purchased Gas Related	1	23,200,304	16,648,538	6,551,766	-	-	-	-	-	-	-	-	-	-
Materials & Supplies	12	15,707,000	5,618,394	1,592,690	402,099	573,306	628,280	218,327	5,183,310	857,602	281,155	204,191	45,550	102,096
Deferred Taxes	14	(628,510,000)	(181,765,092)	(109,235,038)	(25,580,357)	(37,207,792)	(22,060,701)	(16,278,409)	(191,192,742)	(37,082,090)	(3,645,358)	(2,639,742)	(502,808)	(1,319,871)
Customer Deposits	21	(21,600,000)	-	-	-	-	-	-	(5,148,837)	(14,646,216)	(1,021,776)	(626,765)	(9,133)	(147,273)
Investment Tax Credit	14	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Rate Base Elements		(554,442,000)	(134,420,975)	(90,473,880)	(24,181,197)	(35,212,895)	(19,874,513)	(15,518,709)	(178,305,529)	(48,744,160)	(3,688,815)	(2,555,996)	(353,443)	(1,111,888)
Total Measure of Value		**$ 3,169,022,991**	**$ 917,142,710**	**$ 550,606,371**	**$128,939,874**	**$ 187,663,895**	**$ 111,244,603**	**$ 82,046,084**	**$ 963,932,480**	**$ 186,924,574**	**$ 18,199,962**	**$ 13,156,321**	**$ 2,516,808**	**$ 6,649,297**

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 17. ALLOCATION OF OPERATION AND MAINTENANCE EXPENSES ASSOCIATED WITH LARGE MAINS.

Factors are based on the allocation of rate base for large and directly assigned mains.

Service Classification	Original Cost Less Depreciation	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 540,680,086	0.4290
Rate N	352,913,491	0.2799
Rate DS	84,016,030	0.0666
Rate LFD	122,446,440	0.0971
Rate XD Firm	106,646,558	0.0846
Interruptible	54,011,944	0.0428
Total	$ 1,260,714,549	1.0000

FACTOR 18. ALLOCATION OF RATE BASE ASSOCIATED WITH M&R STATION EQUIPMENT AND OTHER DISTRIBUTION ASSETS.

Factors are based on the composite allocation of all mains.

Service Classification	Original Cost Less Depreciation	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 834,761,469	0.4420
Rate N	544,866,718	0.2885
Rate DS	129,713,201	0.0687
Rate LFD	189,046,301	0.1001
Rate XD Firm	106,646,558	0.0565
Interruptible	83,388,697	0.0442
Total	$ 1,888,422,944	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 19. ALLOCATION OF UNCOLLECTIBLE ACCOUNTS.

Factors are based on history of net write-offs by class.

Service Classification	3-Yr. Average of Net Write-offs	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 10,714,163	0.9251
Rate N	749,312	0.0647
Rate DS	8,837	0.0008
Rate LFD	19,905	0.0017
Rate XD Firm	64,418	0.0056
Interruptible	24,812	0.0021
Total	$ 11,581,448	1.0000

FACTOR 20. ALLOCATION OF PENALTY REVENUE.

Factors are based on an analysis of penalty revenue, by class.

Service Classification	Penalty Revenue	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 2,313,287	0.4737
Rate N	1,885,751	0.3861
Rate DS	240,168	0.0492
Rate LFD	264,015	0.0541
Rate XD Firm	91,116	0.0187
Interruptible	89,186	0.0183
Total	$ 4,883,522	1.0000

FACTOR 21. ALLOCATION OF CUSTOMER DEPOSITS.

Factors are based on an analysis of customer deposits for 2021, by class.

Service Classification	2021 Customer Deposits	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 4,510,000	0.2384
Rate N	12,829,000	0.6781
Rate DS	895,000	0.0473
Rate LFD	549,000	0.0290
Rate XD Firm	8,000	0.0004
Interruptible	129,000	0.0068
Total	$ 18,920,000	1.0000

UGI UTILITIES, INC. - GAS DIVISION

CALCULATION OF CUSTOMER COSTS PER BILL BY SERVICE CLASSIFICATION

		Cost of Service (1)	Rate R (2)	Rate N (3)	Rate DS (4)	Rate LFD (5)	Rate XD Firm (6)	Interruptible (7)
Fully Allocated Customer Costs								
Customer Costs		309,125,841	$ 246,155,604	$ 44,545,525	$ 8,285,232	$ 5,943,721	$ 1,189,954	$ 3,005,806
Number of bills		8,264,040	7,393,584	841,500	16,704	7,224	672	4,356
Customer Cost per bill			**$ 33.29**	**$ 52.94**	**$ 496.00**	**$ 822.77**	**$ 1,770.76**	**$ 690.04**
Direct Customer Costs								
O & M Expenses:								
874	Mains And Services Expenses							
	Mains	-	-	-	-	-	-	-
	Services	13,256,219	11,556,771	1,592,072	53,025	33,141	3,977	17,233
876	M & R Station Expenses - Industrial	12,194	-	-	5,434	4,065	734	1,961
878	Meter and House Regulator Expenses	3,245,151	1,381,785	1,437,926	189,517	141,813	25,637	68,473
879	Customer Installations Expenses	2,759,655	1,175,061	1,222,803	161,164	120,597	21,801	58,229
890	M & R Equip - Industrial	4,732,873	-	-	2,108,968	1,577,940	284,919	761,046
892	Services	1,547,016	1,348,688	185,797	6,188	3,868	464	2,011
893	Meters & House Regulators	-	-	-	-	-	-	-
901	Supervision	832,202	744,572	84,718	1,664	749	83	416
902	Meter Reading Expenses	2,208,095	1,975,583	224,784	4,416	1,987	221	1,104
903	Customer Records & Coll Expenses	19,474,018	17,423,404	1,982,455	38,948	17,527	1,947	9,737
903.1	Universal Service Program	-	-	-	-	-	-	-
904	Uncollectible Accounts	10,999,710	10,147,842	668,697	14,366	30,529	100,565	37,712
905	Miscellaneous Cust Accts Expenses	2,318,248	2,074,137	235,998	4,636	2,086	232	1,159
907	Supervision	174,406	156,041	17,755	349	157	17	87
908	Customer Assistance Expenses	714,061	714,061	-	-	-	-	-
910	Miscellaneous Customer Service Exp.	-	-	-	-	-	-	-
911	Supervision	431,364	387,279	44,085	-	-	-	-
912	Demonstrating and Selling Expenses	(677,610)	(608,358)	(69,252)	-	-	-	-
912.1	Energy Efficiency and Conservation	283,600	-	-	163,609	70,758	6,580	42,653
913	Advertising Expenses	1,637,284	1,469,954	167,330	-	-	-	-
916	Miscellaneous	258,000	231,632	26,368	-	-	-	-
926	Employee Pensions and Benefits	12,419,622 *	9,150,003	1,862,271	629,721	463,887	87,399	226,341
408	Payroll Taxes	3,838,556 *	2,828,008	575,576	194,629	143,374	27,013	69,956
Subtotal O & M Expenses		80,464,664	62,156,463	10,259,383	3,576,634	2,612,478	561,589	1,298,118

UGI UTILITIES, INC. - GAS DIVISION

CALCULATION OF CUSTOMER COSTS PER BILL BY SERVICE CLASSIFICATION

		Cost of Service (1)	Rate R (2)	Rate N (3)	Rate DS (4)	Rate LFD (5)	Rate XD Firm (6)	Interruptible (7)
Depreciation Expense								
380	Services	40,073,392	34,935,984	4,812,814	160,294	100,183	12,022	52,095
381	Meters	5,529,932	2,354,645	2,450,313	322,948	241,658	43,686	116,682
382	Meter Installations	3,015,930	1,284,183	1,336,359	176,130	131,796	23,826	63,636
383	House Regulators	137,693	121,032	16,661	-	-	-	-
384	House Regulator Installations	486,457	427,596	58,861	-	-	-	-
385	Industrial M & R Equipment	825,091	351,324	365,598	48,185	36,057	6,518	17,409
390	Structures and Improvements	2,038,344 *	1,583,087	261,929	85,870	62,364	13,912	31,182
391	Office Furniture And Equipment	11,736,884 *	9,665,008	1,383,904	307,649	220,860	48,799	110,664
Subtotal Depreciation		63,843,723	50,722,859	10,686,439	1,101,076	792,918	148,763	391,668
Rate Base								
380	Services	1,027,231,350	895,540,292	123,370,485	4,108,925	2,568,078	308,169	1,335,401
381	Meters	105,716,315	45,014,007	46,842,899	6,173,833	4,619,803	835,159	2,230,614
382	Meter Installations	70,230,279	29,904,053	31,119,037	4,101,448	3,069,063	554,819	1,481,859
383	House Regulators	3,612,616	3,175,489	437,127	-	-	-	-
384	House Regulator Installations	9,602,363	8,440,477	1,161,886	-	-	-	-
385	Industrial M & R Equipment	21,540,899	9,172,115	9,544,772	1,257,989	941,337	170,173	454,513
390	Structures And Improvements	37,036,049 *	28,764,171	4,759,163	1,560,238	1,133,134	252,776	566,567
391	Office Furniture and Equipment	99,898,107 *	82,394,478	11,749,410	2,573,986	1,846,871	407,890	925,472
	Deferred Taxes	(236,382,611) *	(191,192,742)	(37,082,090)	(3,645,358)	(2,639,742)	(502,808)	(1,319,871)
	Customer Deposits	(21,600,000)	(5,148,837)	(14,646,216)	(1,021,776)	(626,765)	(9,133)	(147,273)
Subtotal Rate Base		1,116,885,367	906,063,503	177,256,473	15,109,285	10,911,779	2,017,045	5,527,282
Taxes and Return @ 10.0%		111,230,136	90,234,477	17,652,896	1,504,727	1,086,699	200,877	550,460
Total Direct Customer Costs		$ 255,538,524	$ 203,113,798	$ 38,598,718	$ 6,182,437	$ 4,492,095	$ 911,229	$ 2,240,246
Number of bills		8,264,040	7,393,584	841,500	16,704	7,224	672	4,356
Direct Costs per bill			**$ 27.47**	**$ 45.87**	**$ 370.12**	**$ 621.83**	**$ 1,356.00**	**$ 514.29**

* Customer cost portion of account.

UGI UTILITIES, INC. - GAS DIVISION

CALCULATION OF COSTS RELATED TO LFD AND XD DEMAND CHARGES

Capital Costs	Rate LFD	Rate XD Firm
Depreciation	$ 5,673,859	$ 3,583,925
Taxes Other Than Income	582,788	548,345
Income Taxes	3,750,142	2,223,480
Income Available for Return	14,933,475	8,854,138
Total	$ 24,940,264	$ 15,209,888
Cost Per Month	$ 2,078,355	$ 1,267,491
Demand Volume Units per Month	115,419	821,122
Demand Costs per MCF	$ 18.01	$ 1.54

UGI GAS

EXHIBIT E – PROOF OF REVENUE

BOOK X

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT F – CURRENT TARIFFS
UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S
SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 Effective: March 29, 2022

UGI GAS EXHIBIT F – CURRENT TARIFF

GAS SERVICE TARIFF - PA P.U.C. NO. 7

UGI UTILITIES, INC. – GAS DIVISION

GAS TARIFF

INCLUDING THE GAS SERVICE TARIFF NO. 7

AND

THE CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Service and Choice Aggregation Service

in the

Territory Described Herein

Issued: December 20, 2021

Effective for bills rendered on and after January 1, 2022 in accordance with the Commission Order at Docket No. R-2019-3015162 entered October 8, 2020

Issued By:

Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This tariff makes increases to existing rates (see page 2).

LIST OF CHANGES MADE BY THIS SUPPLEMENT
(Page Numbers Refer to Official Tariff)

Rider I – Distribution System Improvement Charge (DSIC), Pg. 63

- The DSIC rate is increased.

LIST OF CHANGES MADE BY THIS SUPPLEMENT - Continued
(Page Numbers Refer to Official Tariff)

Rate N – General Service – Non-Residential, Page 89.
- The Distribution Charge has been increased and the Customer Charge has been revised. These changes have been phased-in per the Commission’s Order.

Rate NT – General Service – Non-Residential Transportation, Page 90.
- The Distribution Charge has been increased and the Customer Charge has been revised. These changes have been phased-in per the Commission’s Order.

Rate GBM – Gas Beyond The Mains (Piped Propane Service), Page 92.
- The Distribution Charge has been increased and the Customer Charge has been revised in concert with the same change to Rate N/NT. These changes have been phased-in per the Commission’s Order.

Rate DS – Delivery Service, Pages 94-95.
- The Distribution Charge has been increased and the Customer Charge has been revised. These changes have been phased-in per the Commission’s Order.
- Clarifying language addressing the Minimum Monthly Bill has been added. Also, the term Maximum Daily Quantity (“MDQ”) has been defined.

Rate LFD – Large Firm Delivery Service, Page 99.
- Availability language has been modified to remove extraneous language.

Choice Supplier Tariff

Cover Page
- Updated to reflect Supplement Number, Notice language, Issue and Effective dates.

Rule 4, Choice Supplier Obligations, Page 115.
- Subsection 4.12 – The residential and commercial Purchase of Receivable rates have been updated as a result of the change to the Merchant Function Charge.

Rule 10, Rate AG – Aggregation Service, Page 127.
- Failure to Comply with an OFO or DFD penalty charge language has been clarified for application.

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Former South Rate District – Description of Territories **(C)**

BERKS COUNTY

City

Reading

Boroughs

Adamstown (part)	Bally	Birdsboro
Boyertown	Fleetwood	Kenhorst
Kutztown	Laureldale	Leesport
Lyons	Mohnton	Mt. Penn
New Morgan	Robesonia	St. Lawrence
Shillington	Sinking Spring	Topton
Wernersville	West Reading	Womelsdorf
Wyomissing	Wyomissing Hills	

Townships

Alsace	Amity	Bern
Caernarvon	Colebrookdale	Cumru
Douglass	Exeter	Heidelberg
Hereford	Longswamp	Lower Alsace
Lower Heidelberg	Maiden Creek	Marion
Maxatawny	Muhlenberg	Ontelaunee
Perry	Richmond	Robeson
Rockland	Ruscombmanor	South Heidelberg
Spring	Union	Washington

BUCKS COUNTY

Boroughs

Perkasie	Quakertown	Richlandtown
Riegelsville	Sellersville	Silverdale
Trumbauersville		

Townships

Durham	East Rockhill	Haycock
Hilltown	Milford	Nockamixon
Richland	Springfield	West Rockhill

CARBON COUNTY

Borough

East Side

Townships

Banks	Kidder	Packer

(C) Indicates Change

Former South Rate District - Description of Territories – Continued **(C)**

CHESTER COUNTY

Townships

East Coventry (part)	Honey Brook (part)	North Coventry (part)

CUMBERLAND COUNTY

Boroughs

Camp Hill	Carlisle	Lemoyne
Mechanicsburg	Mt. Holly Springs	New Cumberland
Shiremanstown	West Fairview	Wormleysburg

Townships

Dickinson	East Pennsboro	Hampden
Lower Allen	Middlesex	Monroe
North Middleton	Silver Spring	South Middleton
Upper Allen		

DAUPHIN COUNTY

City

Harrisburg

Boroughs

Dauphin	Highspire	Hummelstown
Middletown	Paxtang	Penbrook
Royalton	Steelton	

Townships

Conewago	Derry (incl. Hershey)	East Hanover
Londonderry	Lower Paxton	Lower Swatara
Middle Paxton	South Hanover	Susquehanna
Swatara	West Hanover	

FRANKLIN COUNTY

Townships (Portions)

Greene	Hamilton	Letterkenny (Army Depot)

(C) Indicates Change

Former South Rate District - Description of Territories - Continued **(C)**

LANCASTER COUNTY

City

Lancaster

Boroughs

Adamstown (part)	Akron	Columbia
Denver	East Petersburg	Elizabethtown
Ephrata	Lititz	Manheim
Marietta	Millersville	Mount Joy
Mountville	New Holland	Quarryville
Strasburg		

Townships

Brecknock	Caernarvon	Clay
Conoy	Earl	East Earl
East Cocalico	East Donegal	East Drumore
East Hempfield	East Lampeter	Ephrata
Lancaster	Leacock	Manheim
Manor	Mount Joy	Paradise
Penn	Pequea	Rapho
Strasburg	Upper Leacock	Warwick
West Cocalico	West Donegal	West Earl
West Hempfield	West Lampeter	

LEBANON COUNTY

City

Lebanon

Boroughs

Cleona	Cornwall	Myerstown
Palmyra	Richland	

Townships

Annville	Bethel	Jackson
Millcreek	North Annville	North Cornwall
North Lebanon	North Londonderry	South Annville
South Lebanon	South Londonderry	Swatara
Union	West Cornwall	West Lebanon

(C) Indicates Change

Former South Rate District – Description of Territories – Continued **(C)**

LEHIGH COUNTY

City

Allentown	Bethlehem (part)	

Boroughs

Alburtis	Catasauqua	Coopersburg
Copley	Emmaus	Fountain Hill
Macungie		

Townships

Hanover	Lower Macungie	North Whitehall
Salisbury	South Whitehall	Upper Macungie
Upper Milford	Upper Saucon	Weisenburg
Whitehall		

LUZERNE COUNTY

City

Hazelton

Boroughs

Conyngham	Freeland	West Hazelton
White Haven		

Townships

Butler	Dennison	Foster
Hazel	Hollenback (part)	Sugarloaf

MONROE COUNTY

Borough

Mount Pocono

White Haven

Townships

Chestnuthill	Coolbaugh	Paradise
Pocono	Tobyhanna	Tunkhannok

MONTGOMERY COUNTY

Townships

Douglas	New Hanover	Limerick (Restricted Area)

(C) Indicates Change

Former South Rate District - Description of Territories - Continued **(C)**

NORTHAMPTON COUNTY

Cities

Bethlehem (part)	Easton

Boroughs

Bath	Freemansburg	Glendon
Hellertown	Nazareth	Northampton
North Catasauqua	Stockertown	Tatamy
West Easton	Wilson	

Townships

Allen	Bethlehem	Bushkill
East Allen	Forks	Hanover
Lower Mount Bethel	Lower Nazareth	Lower Saucon
Palmer	Upper Nazareth	Williams

SCHUYLKILL COUNTY

Borough

McAdoo

Townships

East Union	Kline

YORK COUNTY

Townships

Fairview	Newberry

(C) Indicates Change

Former North Rate District - Description of Territory (C)

CLINTON COUNTY

Township

Crawford	Gallagher	Grugan
Wayne		

COLUMBIA COUNTY

Boroughs

Berwick	Briar Creek	

Town

Bloomsburg

Townships

Briar Creek	Mifflin	South Centre
Hemlock	Montour	Scott

LACKAWANNA COUNTY

Cities

Carbondale	Scranton	

Boroughs

Archbald	Dunmore	Olyphant
Blakely	Jermyn	Taylor
Clarks Green	Mayfield	Throop
Clarks Summit	Moosic	Vandling
Dalton	Moscow	Jessup
Dickson City	Old Forge	

Townships

Abington	Glenburn	Ransom
Benton	Greenfield	Roaring Brook
Carbondale	Jefferson	Scott
Clifton	La Plume	South Abington
Covington	Madison	Spring Brook
Elmhurst	Newton	West Abington
Fell	North Abington	

(C) Indicates Change

Former North Rate District – Description of Territory – Continued **(C)**

LUZERNE COUNTY

Cities

Nanticoke	Wilkes-Barre	Pittston

Boroughs

Ashley	Harvey's Lake	Plymouth
Avoca	Kingston	Pringle
Courtdale	Laflin	Shickshinny
Dallas	Larksville	Swoyersville
Dupont	Laurel Run	Sugar Notch
Duryea	Luzerne	Warrior Run
Edwardsville	Nescopeck	West Wyoming
Exeter	New Columbus	Wyoming
Forty Fort	Nuangola	Yatesville

Townships

Bear Creek	Hollenback	Pittston
Buck	Hunlock	Plains
Conyngham	Huntington	Plymouth
Dallas	Jackson	Rice
Dorrance	Jenkins	Ross
Exeter	Kingston	Salem
Fairmount	Lake	Slocum
Fairview	Lehman	Union
Franklin	Nescopeck	Wilkes-Barre
Hanover	Newport	Wright

LYCOMING COUNTY

City

Williamsport

Boroughs

Duboistown	Montoursville	South Williamsport
Montgomery	Muncy	

Townships

Anthony	Jordan	Old Lycoming
Armstrong	Limestone	Penn (Part)
Bastress	Loyalsock	Shresbury (Part)
Brady	Lycoming	Susquehanna
Clinton	Millcreek	Upper Fairchield
Eldred	Moreland	Washington
Fairfield	Muncy	Wolf (Part)
Franklin	Muncy Creek	Woodward
Hepburn		

(C) Indicates Change

Former North Rate District - Description of Territory - Continued **(C)**

MONTOUR COUNTY

Borough

Danville

Townships

Cooper	Mahoning	Valley
Limestone		

NORTHUMBERLAND COUNTY

City

Sunbury

Boroughs

Milton	Riverside	Watsontown
Northumberland	Turbotville	

Townships

Delaware	Point	Upper Augusta
Lewis Twp.	Turbot	West Chillisquaque

PIKE COUNTY

Boroughs

Milford

Townships

Lehman	Milford	Westfall
Dingman		

SNYDER COUNTY

Boroughs

Selinsgrove	Shamokin Dam

Townships

Middlecreek	Monroe	Penn

(C) Indicates Change

Former North Rate District - Description of Territory - Continued **(C)**

SUSQUEHANNA COUNTY

Boroughs

Forest City	Uniondale

Townships

Auburn	Clifford

UNION COUNTY

Townships

Buffalo (Part)	Kelly (Part)	West Buffalo (Part)
East Buffalo (Part)	Union (Part)	White Deer
Gregg	Lewis	

WAYNE COUNTY

Boroughs

Bethany	Hawley	Honesdale
Waymart		

Townships

Berlin	Clinton	Palmyra
Canaan	Dyberry	Paupack
Cherry Ridge	Oregon	Texas

WYOMING COUNTY

Boroughs

Factoryville	Meshoppen	Tunkhannock
Laceyville	Nicholson	

Townships

Braintrim	Lemon	Northmoreland
Clinton	Mehoopany	Noxen
Eaton	Meshoppen	Overfield
Exeter	Monroe	Tunkhannock
Falls	Nicholson	Washington
Forkston	North Branch	Windham

(C) Indicates Change

Former Central Rate District - Description of Territory (C)

ADAMS COUNTY

Townships

Cumberland	Freedom

ARMSTRONG COUNTY

Cities

Parker

BEDFORD COUNTY

Boroughs

Bedford	Everett

Townships

Bedford	Monroe	Snake Spring Valley
Colerain	Napier	West Providence

BERKS COUNTY

Boroughs

Hamburg	Shoemakersville	Leesport	Centerpoint

Townships

Centre	Perry	Tilden	Windsor
Jefferson			

BLAIR COUNTY

Boroughs

Martinsburg	Roaring Spring

Townships

Huston	North Woodbury	Taylor	Woodbury

BRADFORD COUNTY

Boroughs

Alba	Canton	Sylvania	Troy
Burlington			

Townships

Armenia	Columbia	Ridgebury	Troy
Burlington	Granville	Smithfield	Wells
Canton	LeRoy	South Creek	West Burlington
		Springfield	Ulster

(C) Indicates Change

Former Central Rate District - Description of Territory - Continued **(C)**

CARBON COUNTY

Boroughs

Bowmanstown	Lehighton	Palmerton	Weissport
Jim Thorpe			

Townships

East Penn	Lower Towamensing	Mahoning (part)

CENTRE COUNTY

Boroughs

Philipsburg	South Philipsburg

Townships

Rush

CHESTER COUNTY

Boroughs

Oxford

Townships

East Nottingham	Lower Oxford	Upper Oxford	West Nottingham
Elk			

CLARION COUNTY

Boroughs

Callensburg	Silgo

Townships

Ashland	Highland	Monroe	Salem
Beaver	Knox	Paint	Toby
Clarion	Licking	Perry	Washington
Elk	Limestone	Piney	
Farmington	Millcreek	Richland	

CLEARFIELD COUNTY

Boroughs

Chester Hill		Curwensville	Wallaceton
Clearfield and Environs			

(C) Indicates Change

Former Central Rate District - Description of Territory - Continued **(C)**

Description of Territory

Townships

Boggs	Decatur	Lawrence	Pike
Bradford	Knox	Morris	

CLINTON COUNTY

Cities

Lock Haven

Boroughs

Avis	Flemington	Renovo	South Renovo
Beech Creek	Mill Hall		

Townships

Allison	Bald Eagle	Chapman	Noyes
Beech Creek	Castanea	Dunnstable	Pine Creek
(portion)	Wayne	Woodward	

COLUMBIA COUNTY

Boroughs

Centralia

Townships

Conyngham

CUMBERLAND COUNTY

Boroughs

Shippensburg

Townships

Shippensburg	Southampton

DAUPHIN COUNTY

Townships

Jackson	Jefferson	Lykens	Rush
Williams			

FOREST COUNTY

Boroughs

Tionesta

Townships

Barnett	Harmony	Tionesta
Green	Jenks	

(C) Indicates Change

Former Central Rate District - Description of Territory - Continued **(C)**

FRANKLIN COUNTY

Boroughs

Orrstown	Shippensburg	Waynesboro	

Townships

Greene (portion)	Guilford (portion)	Southampton	Washington

FULTON COUNTY

Boroughs

McConnellsburg

Townships

Ayr(portion)	Todd

HUNTINGDON COUNTY

Boroughs

Huntingdon	Mapleton	Mill Creek	Mount Union

Townships

Brady	Juniata	Shirley	Union
Henderson	Oneida	Smithfield	Walker

JEFFERSON COUNTY

Boroughs

Summerville

Townships

Barnett

JUNIATA COUNTY

Townships

Tuscarora	Lack	Milford

LANCASTER COUNTY

Townships

Colerain	Little Britain

LEBANON COUNTY

Townships

Cold Spring	East Hanover

(C) Indicates Change

Former Central Rate District - Description of Territory - Continued **(C)**

LEHIGH COUNTY

Boroughs

Slatington

Townships

Washington

LUZERNE COUNTY

Cities

Pittston

Boroughs

Exeter	Laflin	Pittston	Yatesville
Hughestown	(portion)	West Pittston	Wyoming

Townships

Jenkins (portion)	Pittston

LYCOMING COUNTY

Boroughs

Hughesville	Jersey Shore	Picture Rocks	Salladsburg

Townships

Jackson	Penn (portion)	Porter	Wolf
Mifflin (portion)	Piatt	Shrewsbury (portion)	
McNett			
Nippenose			

MCKEAN COUNTY

Boroughs

Eldred	Port Allegany	Mount Jewett

Townships

Annin	Eldred	Keating	Norwich
Ceres	Hamlin	Liberty	Otto
			Sergeant

MIFFLIN COUNTY

Boroughs

Burnham	Juniata Terrace	Lewistown	McVeytown

Townships

Armagh	Brown	Granville	Union
Bratton	Derry	Menno	Decatur

(C) Indicates Change

Former Central Rate District - Description of Territory - Continue **(C)**

MONROE COUNTY

Boroughs

Delaware Water Gap	East Stroudsburg	Stroudsburg

Townships

Eldred	Middle Smithfield	Ross	Stroud
Hamilton	Pocono	Smithfield	

MONTOUR COUNTY

Township

Liberty (portion)

NORTHAMPTON COUNTY

Boroughs

Bangor	Pen Argyl & Vicinity	Walnutport	Wind Gap
East Bangor	Roseto	Portland	

Townships

Bushkill	Plainfield	Upper Mt. Bethel	Washington
Lehigh			

NORTHUMBERLAND COUNTY

Cities

Shamokin	Sunbury

Boroughs

Kulpmont	Marion Heights	Mount Carmel	Snydertown

Townships

Coal	Little Mahanoy	Ralpho	Washington
East Cameron	Lower Augusta	Rockefeller	West Cameron
Jordan	Mount Carmel	Shamokin	Zerbe
East Chillisquaque	Point	West Chillisquaque	Upper Augusta

(C) Indicates Change

Former Central Rate District - Description of Territory - Continued **(C)**

POTTER COUNTY

Boroughs

Austin	Coudersport	Hebron	Shinglehouse
Bingham	Galeton	Oswayo	Ulysses

Townships

Abbott	Hector	Pleasant Valley	Sylvania
Allegany	Hebron	Portage	Ulysses
Clara	Homer	Roulette	West Branch
Eulalia	Keating	Sharon	Wharton
Genesee	Oswayo	Summit	
Harrison	Pike	Sweden	

SCHUYLKILL COUNTY

Cities

Pottsville

Boroughs

Ashland	Gilberton	Middleport	Palo Alto
Auburn	Girardville	Minersville	Port Carbon
Cressona	Gordon	Mount Carbon	Port Clinton
Deer Lake	Landingville	New Philadelphia	Ringtown
Frackville	Mechanicsville	Orwigsburg	St. Clair
			Schuylkill Haven

Townships

Blythe	Foster	North Manheim	Upper Mahantongo
Branch	Hubley	Norweigan	South Manheim
Butler	Mahanoy (portion)	Ryan	West Brunswick
East Norwegian	New Castle	Union	West Mahanoy
Cass			

(C) Indicates Change

Former Central Rate District - Description of Territory - Continued (C)

TIOGA COUNTY

Boroughs

Blossburg	Lawrenceville	Roseville	Westfield
Elkland	Liberty	Tioga	
Knoxville	Mansfield	Wellsboro	

Townships

Bloss	Delmar	Lawrence	Rutland
Brookfield	Duncan	Liberty	Shippen
Charleston	Elkland	Middlebury	Sullivan
Chatham	Farmington	Nelson	Tioga
Clymer	Gaines	Osceola	Union
Covington	Hamilton	Putnam	Ward
Deerfield	Jackson	Richmond	Westfield

UNION COUNTY

Boroughs

Lewisburg

Townships

Buffalo	East Buffalo	Kelly	Union (portion)

VENANGO COUNTY

Cities

Oil City

Boroughs

Rouseville	Sugarcreek

Townships

Clinton	Cranberry	President	Rockland
Cornplanter	Pinegrove	Richland	

(C) Indicates Change

DEFINITIONS – GENERAL

Alternate Fuel:	Any fuel other than natural gas.
Applicant:	Any person, corporation or other entity that (i) desires from the Company natural gas or any other service provided for in this Tariff at a specific location, (ii) complies completely with all Company requirements for obtaining natural gas or any other service provided for in this Tariff, (iii) has filed and is awaiting Company approval of its application for service, and (iv) is not yet lawfully receiving from the Company any service provided for in this Tariff at such location.
Authorized Payment Agent:	An agent expressly authorized by Company to accept payments from Customers on behalf of Company.
Automated Meter Reading (“AMR”):	Metering using technologies that automatically read and collect data from metering devices and transfer that data to a central database for billing and other purposes and does not include a Remote Meter Reading Device. All meter readings by an AMR shall be deemed actual readings.
BTU (British Thermal Unit):	The amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit. **(C)**
Ccf:	100 cubic feet of gas. This is a measure of gas usage.
CFH:	Cubic feet per hour.
CCFD:	One Hundred Cubic feet per day.
Chapter 56:	The PUC regulations that govern metering, billing and collections for residential gas and electricity service.
City Gate:	A point of interconnection between the Company’s facilities and third party source of supply.
Combined Billing:	The aggregation of the billing determinants of two or more meters of the same Customer at the same location for billing purposes. This applies to only contiguous properties with the same billing/meter read date.
Consolidated Billing:	The aggregation of two or more Customer bills to one bill from different service locations or the same service location for ease of Customer receiving one bill for multiple service locations instead of receiving multiple bills. Each meter will be billed under the applicable Tariff rate and will not be considered combined billing. Customer will be required to pay Company to perform such transactions.
Commodity:	The gas delivered to a Customer during the billing month.
Company:	UGI Utilities, Inc. – Gas Division

(C) Indicates Change

DEFINITIONS – GENERAL (Continued)

Commercial Customer:	A Customer who is not classified as an Industrial Customer or a Residential Customer.
Creditworthiness:	An assessment of an Applicant's or Customer's ability to meet bill payment obligations for utility service.
Critical Day:	Any day, determined by company in its sole discretion, when variations in supply or demand could jeopardize the safety or reliability of Company's Gas Service.
Customer:	Any person, corporation or other entity lawfully in receipt of gas service, aggregation and balancing services or interconnection coordination services from the Company under this Tariff.
Customer Charge:	A monthly charge.
Daily Flow Directive ("DFD"):	An order issued by the Company to address system management, including actions necessary to comply with statutory directives and obligations. DFDs will be communicated to affected Customers or NGSs via e-mail if the Customer or NGSs prefer to receive notice in this manner and provide a valid e-mail address, or if no such preference is expressed, either electronically, by telephone, by facsimile, through the use of the media or by an alternate mutually agreed upon method between the Company and the Customer or NGS. Customers and NGSs must provide the Company with a 24-hour contact for DFDs.
Discontinuance of Service:	The cessation of service with the consent of Customer.
Distribution Charges:	Charges to recover the costs the Company incurs to provide the services necessary to deliver natural gas to a Customer from the point of receipt into the Company's distribution system.
Dth ("Dekatherm"):	A measure of the heat content value of gas. Gas usage is determined by multiplying the MCF used by the heat content value of the gas.
Extension Applicant:	Any person, corporation or other entity, whether or not currently receiving from the Company any service provided for in this Tariff, who desires from the Company an extension or expansion of facilities under Section 5 of this Tariff and who complies with all Company requirements for obtaining an extension or expansion of facilities as provided for in this Tariff.
Gas or Natural Gas:	A flammable gas meeting PUC heating value and purity requirements that may include natural gas, synthetic natural gas, propane, landfill gas and any and all natural gas substitutes.
Gas Service:	The furnishing of gas by the Company at the point of delivery regardless of whether the Customer makes any use of the gas.

DEFINITIONS – GENERAL (Continued)

Gas Supply or Commodity Charge:	Charges by an NGS or Supplier of Last Resort to recover the cost of procuring natural gas and delivering it to the Company's facilities for redelivery to Customers.
Industrial Customer:	A Customer engaged in the process which creates or changes raw materials or unfinished materials into another form or product.
Interruptible Service:	Natural gas services that can be temporarily discontinued under terms and conditions specified by Tariff or contract.
MCF:	1,000 cubic feet of gas. This is a measure of gas usage.
Natural Gas Supplier ("NGS"):	Any person, corporation or other entity that has received a license from the PUC to supply natural gas supply services to Customers in the Company's service territory and that has met the additional criteria established by the Company to permit it to provide natural gas supply service to Customers.
Non-Critical Day:	Any day determined by Company not to be a Critical Day
Non-Residential Applicant:	An Applicant not classified as a Residential Applicant.
Non-Residential Customer:	A Customer not classified as a Residential Customer, including a Commercial Customer and an Industrial Customer.
Occupant:	A natural person who resides in the premises to which gas service is provided.
Operational Flow Order ("OFO"):	A directive issued by the Company that is reasonably necessary to alleviate conditions that threaten the operational integrity of the Company's system on a critical day, including actions necessary to comply with statutory directives and obligations. OFOs will be communicated as soon as reasonably practical to affected Customers or NGSs via e-mail if the Customer or NGSs prefer to receive notice in this manner and provide a valid e-mail address, or if no such preference is expressed, either electronically, by telephone, by facsimile, through the use of the media or by an alternate mutually agreed upon method between the Company and the Customer or NGS. Customers and NGSs must provide the Company with a 24-hour contact for OFOs.
Point of Delivery:	The outlet of company facilities; usually the meter or regulator outlet.
Price to Compare:	The dollar amount charged by the Company, used by Customers to compare prices and potential savings with other Natural Gas Suppliers.
PUC:	The Pennsylvania Public Utility Commission.

DEFINITIONS – GENERAL (Continued)

Remote Meter Reading Device: A device which by electrical impulse or otherwise transmits readings from a meter, usually located within a residence, to a more accessible location outside a residence. The term does not include AMR and devices that permit direct interrogation of the meter.

Residential Applicant: An Applicant who is (1) a natural person at least 18 years of age not currently receiving service who applies for residential service, or (2) an adult Occupant whose name appears on the mortgage, deed or lease of the property for which the residential utility service is requested. The term shall not include (1) a Residential Customer who seeks to transfer service within the Company's service territory, or (2) a Residential Customer who, within 30 days after Termination or Discontinuance of Service, seeks to have service reconnected at the same location or transferred to another location within the Company's service territory.

Residential Customer: A Customer who is either (1) a natural person at least 18 years of age in whose name a residential account is listed and who is primarily responsible for payment of bills rendered for the service, or (2) any adult Occupant whose name appears on the mortgage, deed or lease of the property for which residential service is requested. A Residential Customer shall be further defined to include a Customer receiving the Company's gas service to a single-family dwelling or building, through one meter to four or fewer dwelling units in a multi-family dwelling, or premises used as a single family dwelling and for one or more business uses, provided the proprietor of the business resides in the single family dwelling, and the business uses less than fifty percent of the anticipated gas usage served through a single meter. Service will be supplied only where the Company's facilities are suitable to the service desired. A Residential Customer shall remain a Customer after Discontinuance of Service or Termination of Service until the final bill for service is past due. The term includes a person who, within 30 days after Termination or Discontinuance of Service, seeks to have service reconnected at the same location o transferred to another location within the Company's service territory.

Supplier of Last Resort: The Company or another entity that provides natural gas supply services to Customers that do not elect another supplier or choose to be served by the supplier of last resort, Customers that are refused service from another natural gas supplier, or Customers whose natural gas supplier fails to deliver the required gas supplies. Currently, the Company is the supplier of last resort for all Customers under the terms of this Tariff. Each Customer may only have one supplier of last resort with one exception: The Company shall be under no obligation and shall have no duty to serve as Supplier of Last Resort to any Rate DS, IS, LFD, or XD customers.

DEFINITIONS – GENERAL (Continued)

Tariff:	The rates, rules, and regulations set forth herein, as may be amended, modified or superseded from time to time. The Tariff is on file with the PUC and available on the Company's website.
Termination of Service:	The cessation of service, whether temporary or permanent, without the consent of Customer.
Unauthorized Use of Service:	Unreasonable interference or diversion of service, including meter tampering (any act which affects the proper registration of service through a meter), by-passing unmetered service that flows through a device connected between a service line and customer-owned facilities and unauthorized service restoral.
User Without Contract:	A natural person who takes or accepts gas service without the knowledge or approval of the Company, other than the Unauthorized Use of Service as defined above.

RULES AND REGULATIONS

1. THE GAS SERVICE TARIFF

1.1 Agreements. No agent or employee of the Company has authority to make any promise, agreement or representation not consistent with this Tariff.

1.2 Waiver of Rights. The failure by the Company to enforce any of the terms of this Tariff shall not be deemed a waiver of its right to enforce any of the terms of this Tariff.

1.3 Filing and Posting. A copy of this Tariff is on file with the PUC and is available on Company's website at https://www.ugi.com/tariffs **(C)**

1.4 Application of Rates: The rates named in this Tariff are based upon supply to one Customer through one meter at the same or contiguous property. Each service to a different location and/or of a different rate classification shall be billed as a separate Customer. Customers who take service at two or more locations on the same or contiguous property under the same rate schedule may, by request, have their use of gas combined for billing purposes; Customers electing to take advantage of this rule shall pay the cost of all additional service connections required unless, in the Company's sole judgment, the Company's investment in such connections is warranted by the revenue anticipated from the service to be supplied. The Company will provide Customers with a written explanation regarding its analysis of the arrangement's economics. Customers may not pool together for purposes of qualifying for a rate schedule.

1.5 Liability and Legal Remedies: The Customer will indemnify, defend and hold harmless the Company against all claims, demands, costs or expenses for loss, damage, or injury to person or property in any manner either directly or indirectly connected with or growing out of the supply or use of gas service by the Customer at or on the Customer's side of the point of delivery. Neither the Company nor the Customer will be liable to each other for any act or omission caused either directly or indirectly by strikes, labor troubles, accidents, litigation, federal, state or municipal laws or interference, or other causes not a result of each party's own negligence or intentional misconduct.

(C) Indicates Change

RULES AND REGULATIONS

2. CONTRACT FOR GAS SERVICE

2.1 Application for Service. Every Applicant for Gas Service must apply through the Company. Non-Residential Applicants may be required to sign a contract for service consistent with this Tariff.

2.2 Right to Reject. The Company may limit the amount and character of service it will supply. It may reject applications where service is not available, or which might affect service to existing Customers, or for other good and sufficient reasons at the Company's sole discretion.

2.3 Facilities and System Access. Each Customer with a Daily Firm Requirement ("DFR"), Maximum Daily Quantity ("MDQ"), or peak usage capability of 1,000 MCF per **(C)** day or greater shall provide the Company with the opportunity to review plans for the development of all gas facilities to the Customer's premises (including pipelines, mains, service lines and appurtenances), in order to assure safety and reliability, as follows:

(a) If the Customer proposes to acquire, construct or contract for the use of service of gas facilities ("Customer gas facilities"), the Customer will provide advance notice to the Company in writing, at least sixty (60) days in advance of the earlier of the effective date of a contract or commencement date for construction of Customer gas facilities.

(b) The Customer agrees to submit all design and construction specifications and drawings to the Company in advance of construction, which demonstrate compliance with all applicable requirements as to gas main and service construction and pipeline safety. If the Company determines that Customer gas facilities will encroach upon or interconnect with Company facilities, serve common gas utilization equipment with Company facilities or are in the immediate vicinity of Company facilities such that the safety of Company facilities may be adversely affected thereby, the Company shall have the right to approve the design and location of such Customer gas facilities. The Company shall act upon its right to approve such Customer gas facilities within ninety (90) days after the later of submission of all design and construction specifications and drawings to the Company, or Customer notification required under Rule 2.3(a), provided however, if the Company fails to respond in writing within the ninety (90) day time period the Customer may move forward with its project. Customer gas facilities will be deemed to encroach upon the Company's facilities when they would interfere with or prevent the Company from accessing, maintaining or operating its facilities or when the Customer gas facilities would be configured or located in a manner that would cause safety or reliability concerns with respect to the Company's facilities.

(c) If the full sixty (60) day notice required in Rule 2.3(a) is not given by the Customer then the Customer shall be deemed to have granted the Company full authority to discontinue service upon discovery of any safety or reliability concerns. The Company will provide 24 hours' notice unless there are reliability or safety issues that must be addressed immediately. The Company shall not be liable for any costs or damages caused by such service discontinuance.

(C) Indicates Change

RULES AND REGULATIONS

2. CONTRACT FOR GAS SERVICE - Continued

2.4 Selection of Rate Schedules. When the characteristics of usage or service conditions of an Applicant or Customer are such that more than one rate schedule is available, the Applicant or Customer shall select the schedule to be applied. Upon request, the Company will assist to a reasonable extent in selecting the most advantageous schedule. For Customers changing schedules, the Company will bill the Customer under the selected rate beginning with the date of the next scheduled meter reading following notification of the selected rate. When service under a Demand Charge rate commences prior to the installation of equipment for determining the Customer's demand, the Customer's demand for billing purposes will be estimated by the Company.

2.5 Use of Gas. The use of gas shall only be for the purpose and in the places identified by the customer in applying for service. The gas supplied by the Company shall not be resold without the express written permission of the Company. In the event that the Customer uses the gas in an improper or unsafe manner, in violation of this Tariff or any applicable federal, state or municipal laws or codes, the Company may immediately terminate service as described in the Service Discontinuation and Termination section of this Tariff. In the event that any loss is sustained as a result of Customer's improper or illegal use of the gas, the Customer agrees to indemnify, defend and hold harmless Company. The Company will not supply gas for any additional equipment, or any increased usage for any Customer, unless request was filed with the Company prior to the connection or increased usage. The Company reserves the right to limit or discontinue Gas Service or charge Customer upgrade installation charges in order to provide additional Gas Service. Customer is responsible for any loss of Gas Service to other Customers caused by failure to register.

2.6 Distribution System Bypass. Unless otherwise provided by contract, if any Customer or potential Customer of the Company bypasses the Company for all or a portion of their Natural Gas Service needs then the Company thereafter shall have no obligation to serve or maintain the gas supply or physical capacity necessary to serve the Bypass portion of such Customer load, provided, however, that the Company will continue to serve the un-bypassed portion of a bypassing Customer's load consistent with the terms of any existing service agreement and will negotiate new service agreements to continue service so-long as the anticipated revenues justify any costs of providing the service. In addition, to the extent that such Customer returns from a total bypass, the Company shall serve such Customer as a new Customer and shall have the right to charge a negotiated rate for continued, subsequent or standby service that, at a maximum, is established solely by competitive market conditions, which shall reflect the costs of the Customer's alternatives.

2.7 Conditions Under Which Service Will Be Rendered From Transmission or Gathering Lines. The Company does not undertake or hold itself out to serve Customers from its transmission or gathering lines. Applications for service therefore may, at the election of the Company, be accepted where the lines are being operated in a manner which will permit gas to be served to the Applicant without interference with its operations. Applicants, if accepted by the Company, must agree to comply with the Rules and Regulations of the Company and more particularly the following rules applicable to this type of service:

RULES AND REGULATIONS

2. CONTRACT FOR GAS SERVICE - Continued

(a) Applicants agrees that service is only offered with the understanding that the Company's line from which gas is to be supplied is not permanent and that service to the Applicant is subject to temporary or absolute change or discontinuance at the sole discretion of the Company, which may at any time remove, repair, or change the use or manner of operating said line.

(b) Applicants agrees that the Company may at any time cancel service upon thirty (30) days' written notice to the Applicant and Applicant agrees that upon receipt of such notice of cancellation to promptly discontinue service within the said thirty (30) day period, and such cancellation and termination of service shall not be construed as an abandonment of service to such Customer within the meaning of the Pennsylvania Public Utility Code.

(c) The Applicant agrees to accept the gas at the varying pressures at which the line is operated from time to time and Applicant understands that such pressure is not governed by regulators but it is high and low and the Applicant expressly assumes the duty of regulating the flow of the pressure of gas delivered to him and he assumes all risks from variation in pressure, defects in pipe, connections and appliances, from the escape and leakage of gas, from the sticking of valves and regulators and from the burning of gas on his premises and from like causes incident to the use of gas.

(d) The Company shall not be liable for any deficiency in the supply of gas caused by the use of compressing stations, breakage of lines, variations in pressure, discontinuance of service or any other causes.

(e) The Company shall not be liable for any damage arising out of this agreement or the service supplied thereto.

(f) Service shall be at the sole risk of the Customer.

2.8 Government Identification to Establish Service. The Company will accept any current form of government-issued identification, including identification issued by a foreign government, to establish service. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

3. GUARANTEE OF PAYMENT

3.1 Deposits for Non-Residential Accounts. A cash deposit may be required from a Non-Residential Applicant to secure payment of bills for regulated distribution service. In addition, the Company may require a deposit, letter of credit or other adequate assurance of payment, or any combination thereof, from a Non-Residential Customer if the Non-Residential Customer has been delinquent in payment of any bill in the preceding twelve (12) months or the Company otherwise has reasonable grounds to require security for payment of bills. The deposit shall not be more than the bill for regulated distribution service for the estimated usage for one average monthly billing period plus that for the highest billing period within the most recent twelve (12) months with a minimum fifty dollars ($50.00) deposit.

3.2 Additional Security from Large Volume Customers.

(a) Whether or not the Company could otherwise require security for payment, the Company may require a deposit, letter of credit, other adequate assurance of payment, or any combination thereof, to the extent the Customer seeks any combination of delivery or retail service for volumes in excess of 3,000 MCF per month. Such security may be established for an amount as determined by the Company.

(b) In addition, the Company may take one or more of the following actions:

(1) With the agreement of the Customer, reduce the meter reading and billing period to less than one month, require payment in no less than three calendar days from billing.

(2) Require payment by certified check or wire transfer; and

(3) Impose other procedures reasonably designed to reduce potential exposure to credit risk.

(c) The Company may, in its discretion, specify the manner in which security and payments shall be credited and applied to past due or current bills or to replenish security.

3.3 Deposits for Residential Accounts. The Company may require a cash deposit from a Residential Applicant or Residential Customer to secure payment of bills for regulated distribution service based upon the following:

(a) A Residential Applicant or Residential Customer whose service was terminated for any of the following reasons:

(1) Nonpayment of an undisputed delinquent account.

(2) Failure to complete payment of a deposit, providing a guarantee or establish credit.

(3) Failure to permit access to meters, service connections or other property of Company for the purposes of replacement, maintenance, repair, or meter reading.

(4) Unauthorized Use of Service on or about the affected dwelling.

(5) Failure to comply with the material terms of a payment arrangement.

(6) Fraud or material misrepresentation of identity for the purposes of obtaining utility service.

(7) Tampering with meters, including, but not limited to, bypassing a meter or removal of an automatic meter reading device or other Company equipment.

RULES AND REGULATIONS

3. GUARANTEE OF PAYMENT - Continued

(8) Violating tariff provisions on file with the PUC so as to endanger the safety of a person or the integrity of the Company's delivery system.

(b) Any Residential Applicant who is unable to establish creditworthiness to the satisfaction of Company through the use of a generally accepted credit scoring methodology which employs standards for using the methodology that falls within the range of general industry practice and specifically assesses the risk of utility bill payment.

(c) A Residential Customer who fails to comply with the material terms or condition of a settlement or payment arrangement.

(d) A Residential Customer who has been delinquent in the payment of two (2) consecutive bills, or three (3) or more bills within the preceding twelve (12) months.

(e) The Company has established separate credit procedures and standards for Residential Applicants and Residential Customers who are victims with a protection from abuse order or for whom there is a court order from a court of competent jurisdiction in this Commonwealth, which provides clear evidence of domestic violence against the Residential Applicant or Residential Customer. These procedures shall be publicly posted on the Company's website and maintained on file in each of the business offices of the Company and made available, upon request, for inspection by members of the public.

3.4. Amount of Deposit for Residential Accounts. For Residential Applicants, the amount of the cash deposit shall not be more than 1/6 of a Residential Applicant's estimated annual bill, with such estimated annual bill determined at the time the deposit is required. In lieu of a cash deposit from a Residential Applicant, the Company may accept a written third-party guaranty on behalf of the Residential Applicant, provided that the guarantor establishes credit with the Company under Section 3.3 and the terms of the written guaranty are approved in writing by the Company, with such approval not to be unreasonably withheld. For Residential Customers, the amount of the cash deposit shall not be more than the estimated charges for service based on the Residential Customer's prior consumption for the period equal to one average billing period plus one average month, not to exceed two (2) months. Deposit amounts for Residential Applicants and Residential Customers may include Natural Gas Supplier charges where such Supplier is a participant in the Company's Purchase of Receivables Program.

3.5 Payment Period for Deposits.

(a) Any Non-Residential Applicant seeking to establish service at a new or different service location or seeking to reconnect service at the same service location previously terminated or discontinued, shall pay the required deposit in full prior to the provision of service.

(b) Any Residential Applicant or Residential Customer seeking to establish service at a new or different location or seeking to reconnect service at the same service location previously terminated or discontinued shall pay the required deposit in full within 90 days. A Residential Applicant or Residential Customer may elect to pay the required deposit in three installments as follows: 50% of the required deposit billed upon the establishment or reconnection of service, within

RULES AND REGULATIONS

3. GUARANTEE OF PAYMENT - Continued

25% of the required deposit to be billed by the Company 30 days after the establishment or reconnection of service and the remaining 25% billed 60 days after the establishment or reconnection of service. Nothing shall preclude the Residential Applicant or Residential Customer from electing to pay the deposit in full before or on the due date.

(c) Any Customer receiving service from the Company shall pay the required deposit in full on or before the due date. A Residential Customer may elect to pay the required deposit in three installments as follows: 50% of the required deposit billed upon the determination by the Company under Section 3.3(c) or (d) above that the deposit is required, with 25% to be billed by the Company 30 days after the determination and the remaining 25% billed 60 days after the determination.

3.6 Deposit Hold Period for Residential Accounts. A timely payment history is established for a Residential Customer when the Residential Customer has paid in full and on time for twelve (12) consecutive months. Company may hold a deposit on a Residential Customer's account until a timely payment history is established (the "Deposit Hold Period"). At the end of the Deposit Hold Period Company shall credit the deposit, plus accrued interest, to the Residential Customer's account. Deposits credited after the end of the Deposit Hold Period shall first be applied to any past due amounts. If service is terminated or discontinued before the end of the Deposit Hold Period, Company shall deduct any outstanding balance from the deposit and return any positive balance to the Residential Customer within sixty (60) days.

3.7 Refund Provision Non-Residential Customers. Deposits secured from Non-Residential Customers will be refunded when the Customer discontinues service and has no unpaid bills or at Company's sole discretion.

3.8 Adjustments. The amount of the deposit may be adjusted when there is a change in consumption that will significantly change the amount of the deposit as computed in Rule 3.1 and 3.4.

3.9 Interest on Deposits. Deposits from all Customers shall bear interest computed at the simple annual interest rate determined by the Secretary of Revenue for interest on underpayment of tax under Section 806 of the Act of April 19, 1929 (P.L. 343, No. 176), known as The Fiscal Code which will be credited annually to the Customer's deposit or account. The interest rate in effect when the deposit is required to be paid shall remain in effect until the later of the date the deposit is refunded or credited or December 31 of each year. On January 1 of each year, the new interest rate for that year will apply to the deposit. Deposits shall cease to bear interest upon termination or discontinuance of the service covered by the deposit.

3.10 Prior Debts.

(a) Non-Residential Accounts. As a condition of furnishing, transferring or reconnecting service to a Non-Residential Applicant or Non-Residential Customer, the Company may require payment of any outstanding balance on any account for which the Non-Residential Applicant or Non-Residential Customer is legally responsible.

RULES AND REGULATIONS

3. GUARANTEE OF PAYMENT - Continued

(b) Residential Accounts. As a condition of furnishing, transferring or reconnecting service to a Residential Applicant or Residential Customer, the Company may require payment of any outstanding balance which accrued within the past four years on any account for which the Residential Applicant or Residential Customer is legally responsible. The foregoing four-year limitation shall not apply if the outstanding balance includes past due amounts that the Company was not aware of due to Unauthorized Use of Service, fraud or theft; in which case, the Company may require payment of all such past due amounts without regard to the four-year limitation. The Company may render a make-up bill to a Residential Customer for previously unbilled service which accrued within the past four (4) years resulting from billing error, meter failure, leakage that could not reasonably have been detected or loss of service. If the make-up bill exceeds the otherwise normal estimated bill for the billing period during which the make-up bill is issued by at least 50% or at least $50, whichever is greater, the Company shall, at the option of the Customer, amortize the bill at least as long as: (1) the period during which the excess amount accrued; or (2) necessary so that the quantity of service billed in any one billing period is not greater than the normal estimated quantity for that period plus 50%.

(c) The Company may utilize all means of determining an Applicant's or Customer's liability for any outstanding balances, including, but not limited to, the following: (1) use of Company records that contain confidential information previously provided to the Company, (2) information contained on a valid mortgage, lease or deed, (3) other information contained in the Company's records that indicate that the Applicant was an adult Occupant during the time the balances accrued, (4) use of commercially available consumer credit reporting service, (5) use of commercially available skip tracing software that contains records of names and addresses, and (6) use of information contained in credit reporting data utilized by the Company.

RULES AND REGULATIONS

4. SERVICE - SUPPLY FACILITIES

4.1 Facilities Ownership. Unless otherwise mutually agreed in writing that particular facilities are owned by the Customer, and except as provided in Sections 4.3 below, the Company will own and maintain any facilities required for the supply of Gas Service up to the outlet side of its metering equipment, including but not limited to, any mains, service lines, meters, regulators, connections or other equipment. All such equipment shall remain the exclusive property of the Company.

4.2 Facilities Location. The location of the Company's facilities shall in all cases be determined by the Company. The Customer shall provide, without charge, a suitable place for the meters, regulators or other equipment of the Company. The Customer is responsible to provide the connection point to the Customer's fuel line at a location adjacent to the terminus of Company facilities and where the connections are not concealed. Such service line, meter and connection locations shall be accessible to the Company's employees for the safe installation, operation, inspection and maintenance of the facilities and shall be, at all times, readily accessible, and if inside, free of excessive temperature variations, with ample passageway, and whether inside or outside, free of obstacles, and unsafe and hazardous conditions and, if not accessible, the Company has ability to charge the Customer to move facilities to a location acceptable to the Company. The owner of a premises receiving or capable of receiving natural gas service from Company shall be deemed to consent to the location of Company facilities on the premises.

4.3 Customer Convenience Valve. Company may, in its sole discretion, install a valve on the outlet side of its metering facilities which shall be owned by the owner of the premises ("Customer Convenience Valve"), and the owner of the premises may, under such conditions as may reasonably be established by Company, operate the Customer Convenience Valve after it is connected to the premise's fuel lines.

4.4 Fuel Line Designation. When two or more meters are installed on one premises, such as an office building or an apartment house, they shall be grouped at one common place accessible for reading and testing. In such an installation, each fuel line pipe shall bear a tag showing the apartment or area served, supplied by and maintained by the Customer. In cases where it is not possible to group meters at one accessible place, they shall be located as directed by the Company.

4.5 Facilities Relocation.

(a) Changes in location of mains, service lines, meters, regulators, connections or other equipment for the accommodation of the Customer shall be done by the Company, unless otherwise mutually agreed, at the expense of the Customer. This provision includes the relocation of facilities by the Company where obstructions limit Company access to its facilities.

RULES AND REGULATIONS

4. SERVICE - SUPPLY FACILITIES - Continued

(b) Ancillary Fuel Line Work. The Company may, in its sole discretion, when relocating its facilities, make reasonable modifications or additions to the fuel lines of a premises receiving or capable of receiving gas service for the limited purpose of connecting such fuel lines to Company's relocated facilities, and the owner of the premises shall thereafter own and have responsibility for such modified fuel lines. If Company relocates its facilities solely for its convenience or to comply with regulatory requirements it shall pay the costs of relocating or extending the fuel line; otherwise, unless otherwise agreed by Company, the person requesting or requiring the relocation shall be responsible for payment.

4.6 Right of Removal. The Company shall have the right to remove its facilities from the premises of the Customer or, where appropriate, abandon facilities in place, at any time after the termination of service, whatever may have been the reason for such termination.

4.7 Non-Standard Service. The Customer may be required to pay the cost of any special installation necessary to meet Customer's requirements for Gas Service at non-standard conditions.

4.8 Protection of Company Facilities. The Company may condition its provision or continued provision of Gas Service to a Customer on: (a) installation by Customer of equipment, such as check valves or regulation equipment, downstream from Company-owned facilities reasonably necessary to protect Company facilities or service levels, or (b) the installation by Company of equipment, such as valves designed to limit the flow of gas to levels Customer is permitted to receive, reasonable necessary to protect Company facilities or service levels. Unless otherwise agreed to by the Company, the Customer shall be responsible for the costs of such facilities required under this Section 4.8.

4.9 Excess Flow Valves. The Customer may be required to pay the cost of installation of an excess flow valve, upon a Customer's request for an excess flow valve, for a service location that had not been scheduled by the Company for a service line replacement or a new service line prior to the Customer's request for the installation of an excess flow valve.

RULES AND REGULATIONS

5. EXTENSION REGULATION

5.1 Obligation to Extend or Expand. **(C)**

(a) Under the rules set forth below and under normal conditions of construction and installation, upon written application, the Company will extend or expand its facilities within its service territory, provided that (a) the requested extension or expansion will not adversely affect the availability or deliverability of gas supply to existing customers and (b) the Company's investment in facilities is warranted by the Annual Base Revenue to be derived from the extension. The costs of extending or expanding facilities beyond the Company’s Allowable Investment Amount shall be paid by the Extension Applicant as a contribution. Extension contributions may be excused, in whole or in part, in accordance with Rule 5.1(b). Upon request, the Company will provide Customers with a written explanation and reasonable detail of the cost-benefit analysis used in clause (b) above including estimated project costs, the Company’s maximum allowable investment, and the Company’s Annual Base Revenues. In addition, the Company will provide the Customer with a written timetable for the anticipated construction of the upgrade and written notice of completion.

(b) No contribution amount shall be required for an extension of facilities if all of the following conditions, as determined by the Company, are met:

(1) Service location is directly accessible from an existing or proposed (non-high pressure) Company main that would be extended up to one hundred fifty (150) feet;

(2) Service length is one hundred fifty (150) feet or less;

(3) Customer will utilize gas service as their primary heating source and be served under Rates R, RT, N or NT;

(4) Construction does not cross third party non-public property, private right-of-way or complex obstruction (stream, culvert, excessive hillside, etc.)and does not present any abnormal or unusual construction conditions or require unusual permitting requirements.

(5) Extensions not meeting all of the above conditions (1) through (4) shall have the Company’s Allowable Investment Amount determined upon incremental investment amounts required beyond those permitted by the construction conditions stated above.

(6) These modified extension provisions shall not be applied to customers along existing GET Gas designated mains nor be permitted as a method to extend existing GET Gas mains where GET Gas surcharge payments remain in effect. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

5. EXTENSION REGULATION - Continued

(C)

5.2 General

(a) Annual Base Revenue. As used in this Section 5, the Annual Base Revenue is the anticipated annual base rate revenue from the extension or expansion, as determined by the Company, less the cost of fuel included in base rates. Where gas is used as a supplemental source of fuel for peak heating purposes, anticipated base revenues from such use shall be excluded from Annual Base Revenue.

(b) Allowable Investment Amount. The Company's Allowable Investment Amount shall be the Annual Base Revenue divided by a predetermined rate of return.

(c) Estimates and non-standard costs. Cost estimates used by the Company may be based on construction and installation conditions anticipated for the extension, including, but not limited to, the cost of installation and construction: non-street surface restoration, such as replacement or repair of sidewalks, driveways, landscaping or sod; street opening and restoration terms and fees; and any other local government fees required for the installation. The Company may determine cost estimates based on average experienced unit costs.

(d) Surface Restoration. The Company will restore the street surface in accordance with applicable local government regulations and provide rough backfilling of the installation trench from the curb to the meter. The Extension Applicant will be required to perform or pay the Company's cost of non-street surface restoration.

(e) Standard conditions of construction in a residential development, commercial park and industrial park include trenching provided by the developer.

5.3 Residential and Small Commercial Gas Service. For Gas Service to individually metered, single dwelling units, the Company will install required service facilities, including, as applicable, a meter, regulator, service-supply pipe and supply-main, provided the costs in excess of the Allowable Investment Amount shall be paid by the Extension Applicant.

5.4 Commercial and Industrial Gas Service (including apartment buildings and multi-unit housing)

(C) Indicates Change

RULES AND REGULATIONS

5. EXTENSION REGULATION –Continued

(a) For commercial and industrial Gas Service costing up to $10,000 from which the Company in its sole judgment anticipates long-term, continuous usage at projected volumes, the Company will install, required service facilities, including, as applicable, a meter, regulator, service-supply pipe and supply-main, provided that the costs in excess of the Allowable Investment amount shall be paid by the Extension Applicant.

(b) The Company may condition its agreement to extend or expand its facilities upon satisfactory long-term and short-term usage commitments and any other terms and conditions of service as are mutually agreeable to the Company and the Extension Applicant. A contribution may be required up to the amount of the Company's total investment in the extension.

5.5 Contributions and Refunds

Except as otherwise described herein, when a contribution is required by the Company, the terms and conditions of refunds and or future payments that may be required of the Extension Applicant will be governed by the service agreement between the Company and the Extension Applicant. The terms of any refund due to the Extension Applicant shall be defined in the service agreement and shall be limited to a maximum refund of the amount of the original contribution (no interest) and shall be limited to the five-year period immediately following completion of this extension.

5.6 Taxes on Contributions for Construction & Customer Advances.

Any contribution, advance or other like amounts received from the Extension Applicant which shall constitute taxable income as defined by the Internal Revenue Service, will have the income taxes recorded in a deferred account for inclusion in rate base in a future rate case proceeding. Such income taxes associated with a contribution or advance will not be included as part of the contribution or advance charged to the Extension Applicant.

5.7 Daily Metering.

The Company reserves the right as a condition of service under non-residential Tariff rate schedules to install, at the Customer’s expense, remote read devices for the purposes of monitoring and/or billing Customer volumes, at every single meter or multimeter location served under such rate schedules. The Customer shall at all times, at the discretion of the Company, maintain, at its expense, a suitable telecommunication and electric lines to the device which will allow the Company unlimited remote access to the remote read device. If the Customer fails to maintain a suitable telecommunication connection and electric lines to the device, the Company reserves the right to install and maintain telecommunication and, as applicable, electric lines to serve the remote read device and charge the Customer accordingly.

Standard access to daily usage information shall be provided by the Company to the Customer, or Customer's agent, at no additional charge in a form and manner as specified by the Company. Custom reports, access to historical data beyond one month and/or multiple user access may be provided on an as-available basis by the Company for an additional fee.

RULES AND REGULATIONS

5. EXTENSION REGULATION –Continued

5.8 – Pilot Growth Extension Tariff ("GET Gas") Rider

5.8.1 Availability and Purpose. In lieu of the extension rules set forth in Rules 5.1-5.7, the following GET Gas tariff rules may apply. These GET Gas tariff rules will be applied to eligible customers as part of a ten-year pilot program ending November 4, 2024, unless suspended or terminated earlier pursuant to Rule 5.8.4 or Commission order. **(C)**

The GET Gas pilot program is designed to test new tariff rules to facilitate the extension of natural gas service to the general class of residential homes and non-residential buildings, not currently receiving natural gas distribution service, which:

(a) are in an Unserved Area (a small group or pocket of customers in a neighborhood location in close proximity to an existing main) or an Underserved Area (a significant portion of a general community or town location or municipality where the Company has identified significant potential for natural gas service demand and existing natural gas facilities are located within a reasonable distance);

(b) are reasonably expected over time to reach target customer saturation levels which will produce revenues, including GET Gas Rider charges, that will support required investments and not unduly burden existing customers; and

(c) otherwise meet the applicable requirement conditions of the GET Gas program.

Under the GET Gas Program, the Company may designate Company facilities extended to an applicant or applicants, as "GET Gas Facilities" and will assess an incremental GET Gas Rider charge amount related to the recovery of GET Gas amounts, as determined on a general class basis, from the class of customers who may connect to these GET Gas facilities during an initial twelve-year period.

5.8.2 Designation. Subject to the funding limitations set forth in Rule 5.8.5, Company may apply the GET Gas program tariff rules to service extension requests which exceed a cost of $15,000 from an Underserved Area or an Unserved Area reasonably designated by Company, where:

(a) there is, in the Company's sole discretion, a reasonable prospect that (i) fifty percent (50%) or more of existing residential homes along the GET Gas project facility extension route or area will convert their primary heating source to natural gas and directly connect to the GET Gas facilities within 12 years ("GET Gas Customers"); and

(b) the estimated total investment for each GET Gas Customer to be connected does not exceed $10,000 (inclusive of any projected commercial customers).

(C) Indicates Change

RULES AND REGULATIONS

5. EXTENSION REGULATION – Continued

5.8.3 Get Gas Rider. Customers receiving service by connections to Company facilities designated by Company as GET Gas pursuant to Rule 5.8.2 within an initial twelve years following installation, and which receive service under Rate Schedules R, RT, N or NT, shall be required to pay GET Gas Rider charges listed below as part of distribution service for a period of ten years, beginning from the first date the meter is set. GET Gas Rider charges will not be considered Basic Natural Gas Service Charges during the Pilot Period. Non-residential customers subject to the GET Gas Rider charge, as determined by the Company in its sole discretion, may not avoid the charge by electing an alternate rate schedule. In lieu of paying the monthly GET Gas Rider charges, Customers may elect at any time to pay a lump sum upfront payment equal to the remaining principal portion of the GET Gas surcharge. The lump sum upfront payment made by Non-Residential Customers shall be based on anticipated annual customer usage, as determined by the Company in its sole discretion.

GET Gas Rider Rate effective October 11, 2019: **(C)**
<u>Rate Schedules R and RT:</u> $29.00 monthly charge
<u>Rate Schedules N and NT:</u> $20.03 monthly charge plus $1.87 per Mcf for all usage.

However, the GET Gas Rider Rate for customers accepted by the Company before October 29, 2019 at the following rates shall remain unchanged: **(C)**
<u>Rate Schedules R and RT:</u> $21.75 monthly charge
<u>Rate Schedules N and NT:</u> $13.08 monthly charge plus $1.07 per Mcf for all usage.

5.8.4 Limitations. If the differential between Average Residential Annual Natural Gas Costs per MMBtu and Average Residential Annual Heating Oil Costs per MMBtu drops and remains below $10.00 per MMBtu for two consecutive quarters (with such calculations performed for the quarters ending March, June, September and December), the Company will evaluate whether to continue to invest in new GET Gas facilities based on market specifics at that time, except that the Company will continue to invest in (a) service connections to GET Gas Facilities that are already installed or (b) GET Gas projects that are currently underway or have been committed to by the Company.

For purpose of the above limitation:

Average Residential Annual Heating Oil Costs per MMBtu = (twelve-month future period average of NYMEX "HO" Contract) plus (delivery variable); and

Average Residential Annual Natural Gas Costs per MMBtu = (All applicable Rate R volumetric rates and riders) plus (All applicable Rate R monthly charges, excluding the monthly GET Gas Rider, divided by the current average annual residential volumes)

Company also reserves the right to temporarily close or to terminate the program at its discretion for good cause.

5.8.5 Funding. Funding for this pilot GET Gas tariff program shall be limited to an annual average level not to exceed $15 million for the duration of the ten-year pilot term ending November 4, 2024, absent Commission approval to exceed this amount. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

6. CUSTOMER'S RESPONSIBILITY FOR COMPANY'S PROPERTY

6.1 Maintenance of Company Equipment. Company shall own and maintain Company facilities through the Point of Delivery but shall not be required to install or maintain any pipes, appurtenances or equipment beyond that point, unless specifically provided for in writing.

6.2 Access to Premises. The authorized agents and/or employees of the Company shall have free access at all reasonable times to the premises of the Customer for the purpose of reading meters and disconnecting service, for installing, testing, inspecting, repairing, adjusting or removing any Company property. Authorized agents of the Company shall have immediate access to any premises whenever they believe an unsafe or hazardous condition exists.

6.3 Protection by Customer. The Customer shall be responsible at Customers expense for the protection of the Company's property on his premises and shall not permit any unauthorized person to do any work on such property. In the event of damage or destruction of Company's facilities on Customer's property, the Customer shall pay the costs of repairs, replacement, and/or related costs.

6.4 Tampering and Theft of Service

(a) Tampering. In the event the Company's meter or other equipment is tampered or interfered with, the Customer shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter, and for any repairs or replacements required, as well as for costs of inspections, investigations, and protective installations. Such tampering will be grounds for immediate termination of service without notice as specified in the Termination of Service and Disconnection section of this Tariff.

(b) Theft of service occurs when a person obtains gas, by deception, tampering with Company facilities or other means designed to avoid payment for gas provided by Company. Persons who obtain gas through such means may be subject to civil suit and/or criminal prosecution. If theft of service occurs, the Company may immediately terminate service to the location receiving the unauthorized service.

(1) Before service will be restored to the affected location, the Customer must pay (1) for all gas consumed during the period of unauthorized usage, (2) any delinquent gas service balance, including late fees, (3) reconnection fees, (4) a security deposit, and (5) the costs associated with damage to the Company's meters or equipment.

(2) In the event that the theft of service is referred for criminal prosecution, the Company may deny gas service until the case is concluded and any restitution ordered is paid.

RULES AND REGULATIONS

6. CUSTOMER'S RESPONSIBILITY FOR COMPANY'S PROPERTY - Continued

6.5 Continuity of Service. The Company will endeavor at all times to provide reasonable and continuous service to the Customer. The sole liability of the Company for failure to furnish a sufficient supply of gas or for failure to transport Customer's gas shall be limited to an amount equal to the Customer's proportionate monthly Customer charge for the period of time during which a Gas Service failure occurs during which a supply failure occurs. In no event shall the Company be liable for direct, extraordinary, special, or consequential damages arising in any manner whatsoever as a result of supply failure.

6.6 Notification of Construction. It will be the Customer's responsibility to notify the Company and any applicable federal, state or local agencies (i.e., Pennsylvania's One Call System, Inc.) prior to digging or before any construction occurs on the Customer's property that may impair or prevent access by the Company to its service line or any other equipment located on the Customer's property.

6.7 Gas Leaks. It is the responsibility of the Customer to exercise all due care in the detection of defects, leaks, or other dangerous developments incident to the handling of gas. The Customer agrees to immediately inform Company of any gas leaks and in the event of any resulting loss thereof, failure to do so may result in an evidentiary finding of contributory or comparative negligence on the part of the Customer.

6.8 Suspension of Service. For the purpose of making repairs to the mains or other parts of its system, the Company may suspend service for such periods as may in its sole judgment be necessary.

6.9 Company's Right to Inspect. Piping, fixtures and appliances on Customer's premises must be installed at the expense of the Customer or owner of the property. The Company shall have the right, but shall not be obligated, to examine the Customer's installation and appliances at the time service is first supplied or at any later time. If at any time the installation or appliance is found defective or unsafe, service may be refused or discontinued until Customer has the condition corrected. The Company's inspection, or failure to inspect or reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects or inadequacies in the installation, piping, or appliances, or from violation of the Company rules, or from accidents which may occur upon the premises of the Customer.

RULES AND REGULATIONS

7. METER READING

7.1 Definition of a Cubic Foot. A cubic foot shall be the amount of gas that occupies a volume of one cubic foot at an absolute pressure of 14.73 pounds per square inch and a temperature of 60° Fahrenheit. To determine the volume at conditions other than standard pressures of gas delivered, factors such as those for pressure, temperature, specific gravity, caloric value, and deviation from the laws of ideal gases may be applied.

7.2 Method of Measurement. Gas usage shall be measured by Company owned meters.

7.3 Pressure Correction. At the Customer's request, the Company may allow delivery at an elevated pressure that exceeds the standard pressure of seven-inches water column (7" W.C.). In situations where delivery pressure is two pounds per square inch or greater, the Company may choose to use a fixed factor to account for the higher energy content of the higher pressure gas, whereby the metered volume is multiplied by the pressure factor to determine the correct energy consumed. In cases where the Company agrees to provide delivery service at such an elevated pressure without a fixed factor, a supplemental device will be installed at the Customer's expense to correct the meter reading for pressure and temperature, the cost of which shall be estimated, inclusive of overhead amounts, however, the Company and Customer may negotiate cost responsibility for installation of pressure mechanisms upon mutual agreement. The Company may reject a Customer's request for non-standard service at elevated pressure for system operational reasons, where the Customer does not agree to pay the cost for non-standard service, where applicable, under Rules 4.7, 5.3 or 5.4(a), or for any other reason that the Company may determine at its sole discretion.

7.4 Heating Value Correction. Where direct sources of natural gas, renewable natural gas, synthetic natural gas or other natural gas substituted or blended supplies delivered into the Company's distribution system may vary in heating value content (BTUs per cubic foot), the Company may apply a heating value correction factor to metered usage to adjust for heating values that differ from the Company's applicable annual system wide average value (determined excluding direct sources where heating correction is being applied). This heating correction factor will apply when heating value differences exceed a 2% difference at the customer location. This factor may be adjusted monthly. This tariff provision only applies to decreased heating value content gas entering the Company's system. **(C)**

7.5 Meter Tests. The Company may, from time to time and at its expense, inspect and test its meters. The Customer has the right to have the Company test the meter in service at the Customer's premises, and, upon written request, the Company will, as applicable, remove, seal and test the meter in accordance with the Gas Service Regulations of the Pennsylvania Public Utility Commission ("Regulations") or secure an in-person meter reading to confirm the accuracy of an automatic meter reading device when a customer disconnects service or a new service request is received. Together with the written request for a meter test, the Customer shall deposit with the Company the meter testing fee specified by the Regulations. If the meter tests within the accuracy limits specified by the Regulations, the meter shall be deemed for all purposes to have registered accurately. In such case, no billing adjustment shall be made, and the meter testing fee deposited with the Company shall be credited to the Company. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

7. METER READING (Continued)

7.6 Adjustment for Meter Error. If any meter becomes defective or fails to test accurately, an adjustment will be made to the Customer's bill in accordance with the Regulations and the meter testing fee deposited with the Company shall be refunded to the Customer. **(C)**

7.7 Meter Test Fees. The Company may assess the following service charges: **(C)**

Meter Size:	0 - 500 CFH	$10.00
	501 - 1500 CFH	$20.00
	Over - 1500 CFH	$30.00

(C) Indicates Change

RULES AND REGULATIONS

8. BILLING AND PAYMENT

8.1 Billing Month. Bills are rendered monthly. The Company normally reads meters monthly. However, at its option, the Company may read meters once every two months. In instances where meters are read every two months, the first month's bill will be based on an estimate of the consumption for the first month of the bi-monthly period. Bills are due when rendered and shall be considered as received by the Customer when left at, or mailed to, the address where service is rendered, or such other address as designated by the Customer. A billing month is the period upon which a Customer's monthly charges and consumption are computed and for which a bill is rendered. For Residential Customers, the billing month is a period of not less than 26 or greater than 35 days. An initial bill for a new Residential Customer may be less than 26 days or greater than 35 days; provided however, if an initial bill exceeds 60 days the Residential Customer shall be given the opportunity to amortize the amount over a period equal to the period covered by the initial bill without penalty. A final bill due to the discontinuance may be less than 26 days or greater than 35 days but may never exceed 42 days. In cases involving termination, a final bill may be less than 26 days. In addition, bills for less than 26 days or more than 35 days shall be permitted if they result from rebilling initiated by the Company or Customer dispute to correct a billing problem. Bills for less than 26 days or more than 35 days shall be permitted if they result from a meter reading route change initiated by the Company.

8.2 Estimated Consumption. When the Company is unable to obtain an actual meter reading because of inability to gain access to the meter, or because of extreme weather conditions, emergencies, equipment failures, work stoppages or any other circumstances, the Company will render appropriately marked estimated bills.

8.3 Application of a Rate Schedule. The Company will compute bills under the rate schedule selected by and for which the customer qualifies. In the event the customer does not select a Rate Schedule, the Company may discontinue service or place the Customer on a rate schedule for which the Customer qualifies.

8.4 Budget Billing. Residential Heating Customers may elect an optional billing procedure which averages the estimated Company regulated service costs over a revolving twelve (12) month Budget Billing plan. These Customers will be billed for the use of gas during the next eleven (11) months beginning with whatever month that they select. Company will review the Budget Billing amount on the fourth (4th), seventh (7th) and tenth (10th) months annually adjusting upward or downward the Budget Billing amount based on actual charges to date and projected charges to the end of the twelve (12) month Budget Billing. The twelfth bill will be for usage for the month, with an adjustment for the difference between payments made and actual charges for gas service for the prior eleven (11) months, inclusive. At the conclusion of the budget billing year, any resulting reconciliation amount exceeding $100 may be amortized over a twelve (12) month period upon Residential Heating Customer request.

The optional twelve (12) month Budget Billing plan, as described above, is available to Commercial and Industrial Heating Customers provided that at least seventy-five (75) percent of the Customer's total gas consumption is for space heating. If a Customer has an unpaid balance equal to the amount of two (2) Budget Bill Plan bills, billing under this plan may be terminated by the Company.

8.5 Payment Due Date. The due date for payment of Residential Customers' bills shall not be less than twenty (20) days from the date of mailing and fifteen (15) days for a Non-Residential Customer's bill with the exception that bills to the Commonwealth of Pennsylvania, the Government of the United States, or any of their

RULES AND REGULATIONS

8. BILLING AND PAYMENT - Continued

agencies, and elementary and secondary schools shall be due fifteen (15) days after the date of mailing unless otherwise extended to thirty (30) days by mutual agreement. For all billings, if the due date for payment should fall on a Saturday, Sunday, bank holiday or any other day when the offices of the Company where payments are regularly received are not open to the general public, the due date shall be extended to the next business day. Failure to receive a bill will not release the Customer from payment obligations.

8.6 Date of Payment for Residential Customers. For payments by mail, the effective date of payment shall be the date of the postmark. For payments by mail which are not postmarked or postmarked clearly, the effective date of payment shall be one day prior to receipt. For payments made through electronic transmission, the effective date of payment shall be the date of actual receipt of payment by the Company. For payments made at a branch office or an Authorized Payment Agent, the effective date of payment shall be the date of actual receipt of payment at that location.

8.7 Late Payment Charge. Late Payment Charges will be applied as follows to the balance due which is not paid by the due date including amounts billed by the Company on behalf of natural gas suppliers other than the Company. Residential Customers will be charged a late payment charge of one and one half (1 1/2) percent per month on the balance due not paid by the due date; provided that, for a Residential Customer’s payment by mail, the Company shall not impose a late payment charge unless payment is received more than 5 days after the due date. Non-Residential Customers will be charged five (5) percent per month on the balance due not paid by the due date and an additional one and one half (1 1/2) percent per month for each month thereafter.

8.8 Return Check Service Charge. The Company may impose a service charge of the greater of thirty-five dollars ($35.00) or maximum allowed by Commonwealth of Pennsylvania for each check received in payment of bill(s) which is dishonored and returned by the bank upon which it is drawn. The Company may require a Customer to tender non-electronic payment after the Customer tenders two (2) consecutive electronic payments that are subsequently dishonored, revoked, canceled or otherwise not authorized.

8.9 Due Date Extension Program. Residential Customers meeting the qualification requirements of the Due Date Extension Program shall, upon written application, have the due date for payment of bills for service to their personal residence extended. To qualify, Applicants must submit proof that their sole source of support, and that of others in their household, is derived from a permanent fixed income plan, issuing monthly checks. Under the program, the due date for payment on a bill normally falling due between the sixth day of the month and the twentieth day of the month shall be extended to the first working day after the twentieth of the month. The due date for payment on a bill normally falling due between the twenty-first day of the month and the fifth day of the following month, shall be extended to the first working day after the fifth day of the latter month.

8.10 Application of Payments for Rates RT and NT. Where Company renders a bill for natural gas supply service on behalf of a Choice Supplier and a partial payment received, the partial payment shall first be applied to pre-retail access Company balances and then to post-retail access balances. In the event a customer has a pre-retail access Company balance, partial payment shall be applied in the following order of priority:

RULES AND REGULATIONS

8. BILLING AND PAYMENT - Continued

1. First to outstanding pre-retail access Company balances, or the installation amount on a payment arrangement with the Company on this balance; then to
2. Current regulated Company charges; then to
3. Choice Supplier supply charges; then to
4. Non-Basic Service charges; then to
5. Hardship Energy Fund contributions.

In the event a Customer develops a post-retail access balance, partial payment shall first be applied to the pre-retail access Company balances in the order of priority specified above. Thereafter, partial payment shall be Company applied in the following order of priority:

1. First to outstanding post-retail access Company Balances, or the installat amount on a payment arrangement with the Company on this balance; then to
2. Current regulated Company charges; then to
3. Choice Supplier service charges; then to
4. Non-Basic service charges; then to
5. Hardship Energy Fund contributions.

Where Company renders a budget bill on behalf of a Choice Supplier for Natural Gas Supply service, partial payments shall be applied on a pro rata basis after outstanding pre-retail access balances and post retail access balances have been paid in accordance with the orders of priority specified above. For purposes of this Section, pre-retail access balances means outstanding account balances incurred prior to Customer transferring to Rate RT and NT.

For purposes of this Section, post-retail access balances means outstanding account balances incurred after Customer transfers to Rate RT and NT.

8.11 Joint Billing. Joint Billing provides Customers with one combined account and a combined invoice that displays charges for both their gas and electric service and pertains to Customers that are the same class as described below and receive both gas service from the Company and electric service from UGI Utilities, Inc. – Electric Division ("UGI-ED") at the same premises. Eligible Customers shall be Residential Customers receiving service under Rate Schedules R and RT who are also Residential Customers of UGI-ED receiving electric distribution service under UGI-ED Rate Schedules R, and Commercial and Industrial Customers receiving service under Rate Schedules N and NT who are also Commercial and Industrial Customers of UGI-ED receiving electric distribution service under UGI-ED Rate Schedules GS1, GS4, and GS5, unless they elect otherwise in writing or through mutual agreement with Company. Eligible Customers shall be combined into a single Customer account for service received from the Company and UGI-ED and shall receive combined bills separately listing charges from each company. The Company and UGI-ED shall, for such combined accounts, and subject to applicable statutory and regulatory requirements, establish a reasonable hierarchy of categories for the posting of partial payments to such joint accounts, and within each such category payments shall first be posted, as applicable, to UGI-ED or Electric Generation Supplier charges before being posted to UGI Gas Division or Natural Gas Suppler charges.

RULES AND REGULATIONS

8. BILLING AND PAYMENT - Continued

8.12 Payment Refunds. Refunds due customers greater than two dollars ($2) shall be mailed to the Customer. Refunds less than two dollars ($2) may be picked up at the office within sixty (60) days. After sixty (60) days, the refund shall be applied to Operation Share.

8.13 Unless otherwise stated in this Section 8, Billing and Payment, all billing and payment provisions of this section apply to Customers served under all Company rate schedules, including Rate Schedules RT and NT where a Customer's Choice Supplier also participates in the Company's Purchase of Receivables ("POR") program.

RULES AND REGULATIONS

9. TERMINATION AND DISCONTINUANCE OF SERVICE

9.1 (a) Termination of Service. The Company may terminate service on reasonable notice and remove its equipment in case of Customer's (i) nonpayment of an undisputed delinquent account, (ii) failure to complete payment of a deposit, provide a guarantee of payment or establish credit, (iii) failure to permit access to meters, service connections or other property for the purpose of replacement, maintenance, repair or meter reading, (iv) failure to comply with the material terms of a payment arrangement, or (v) violation of tariff Rules and Regulations. The Company may terminate service promptly and without notice for Customer's (i) Unauthorized Use of Service delivered on or about the affected dwelling or premises, (ii) fraud or material misrepresentation of the Customer's identify for the purpose of obtaining service, (iii) abuse of or tampering with the meters, connections or other equipment of the Company, (iv) violating tariff Rules and Regulations which endanger the safety of a person or the integrity of the Company's distribution system, (v) tendering payment for reconnection of service that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company's notice, or (vi) after receiving termination notice from the Company, tendering payment which is subsequently dishonored under 13 Pa. C.S. § 3502, or, in the case of an electronic payment, that is subsequently dishonored, revoked, canceled or otherwise not authorized and which has not been cured or otherwise made in full payment within three business days of the Company's notice. Prior to restoration of service terminated for any of the foregoing reasons, the Company may require a payment in advance of all arrearages, applicable deposit, and a reconnect charge of seventy-three dollars ($73).

(b) For Residential Customers,in the context of service termination during the period of December 1 through March 31,the Company will use financial information from the Customer provided within the most recent twelve (12) month period to determine if a customer exceeds the 250% federal poverty level threshold. The Company will not require customer information to verify income if the customer has established income verification through receipt of LIHEAP within the past twelve (12) months or if the customer is currently participating in CAP. The Company will accept the following as verification of household income in determining whether an account under Chapter 56 is protected from termination during the period of December 1 through March 31: (i) recent pay stubs or W-2 forms, (ii) access card or statement from Department of Public Welfare ("DPW"), (iii) if a source of income is rental income, then a verified copy of rent receipt(s), (iv) if the Residential Customer receives social security payments, pension payments, disability payments, Supplemental Security Income (SSI) payments, or any other source of fixed income with direct deposit, then a copy of bank statement or benefit letter, (v) child support and/or alimony support verification letter, (vi) if the Residential Customer receives payments from unemployment benefits or workers' compensation, then a copy of the determination letter or check stub, (vii) previous year's income tax statement, (viii) a filed 1099 form showing any interest income, annuity or dividends, and (ix) a verification letter from DPW of any approved cash or crisis grant applicable to the current heating season. **(C)**

9.2 Discontinuance of Service. Any Customer who is about to vacate any premises supplied with gas service or wishes to have service discontinued for any reason shall give at least seven (7) days written notice to the Company and any non-Customer Occupant of the premises to which service is being supplied, specifying the date on which it is desired that service be discontinued. If a Residential Customer requests a Discontinuance of Service at the Residential Customer's residence, and the Residential Customer and the members of the Residential Customer's household are the only Occupants, the Company may discontinue service without additional notice to the affected premise.

(C) Indicates Change

RULES AND REGULATIONS

9. TERMINATION AND DISCONTINUANCE OF SERVICE - Continued

If a Customer (other than a landlord ratepayer) requests a Discontinuance of Service at a dwelling other than the Customer’s residence or at a single meter, multi-family residence, whether or not the Customer’s residence, the Customer must state in writing (under penalty of law) that the premises are unoccupied. If the premises are occupied, the Customer's written notice requesting Discontinuance of Service must be endorsed by all affected Occupants. If the foregoing conditions are not met, the Company may discontinue service at the affected premises upon notice to the affected premises in accordance with Chapter 56. The Customer shall be liable for gas consumed until transfer of the account or the meter shut off. When Discontinuance of Service by Customer is for a period of less than twelve (12) months, the Company may require a payment of customer charges for each month the service has been discontinued in order to have the service restored.

9.3 If service to any Non-Residential Customer is terminated for the reasons set forth in Sections 9.1 (Termination of Service) or discontinued in accordance with 9.2 (Discontinuance of Service) hereof, the Company shall not be under any obligation to resume service to the same Customer at the same premises within twelve months unless it shall receive payment of an amount equal to the minimum bill for each month of the intervening period.

9.4 Reconnect Charge. If service to a Customer is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to such customer, at the same premises, within twelve (12) months from the date service was discontinued, unless they shall first receive a reconnection charge of Seventy-Three Dollars ($73.00). In addition, if the Customer’s service was discontinued at the Customer’s request, a payment of the applicable minimum charge for each month that service was discontinued shall be required. A Customer at the same premise who requests seasonal service and has gas shut off and turned on within twelve-month period shall be billed an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the twelve-month period.

RULES AND REGULATIONS

10. RIDER A

STATE TAX ADJUSTMENT SURCHARGE

The State Tax Adjustment Surcharge is applicable to the net monthly rates and minimum charges contained in this Tariff. The surcharge shown below will be recomputed when a tax rate used in the calculation changes and/or the Company implements a change in rates.

The recomputation of the surcharge will be submitted to the PUC within 10 days after the occurrence of a reason for surcharge recomputation shown above. If the recomputed surcharge is less than the one in effect the Company will, and if more may, submit a tariff or supplement to reflect such recomputed surcharge, the effective date of which shall be 10 days after the filing.

Rider A - State Tax Adjustment Surcharge is 0.01% **(I)**

This Rider applies to Rates R, RT, GL, N, NT, GBM, DS, and LFD.

(I) Indicates Increase

RULES AND REGULATIONS

11. RIDER B

SECTION 1307(F) PURCHASED GAS COSTS

Provisions for Recovery of Purchased Gas Costs

Rates for each MCF (1,000 cubic feet) of gas supplied under Rate Schedules R, N, and GL of this Tariff shall include purchased gas costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. Such rates for gas service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the PUC's regulations, to reflect changes in the level of recovery of purchased gas costs.

Computation of Purchased Gas Costs per MCF

Purchased gas costs shall be computed to the nearest one-hundredth cent (0.01¢) per MCF in accordance with the formula set forth below:

$$PGC = \frac{(C-E)}{(S)}$$

Projected purchased gas costs, so computed, shall be included in rates charged to Customers for gas service pursuant to the rate schedules identified above for consecutive twelve-month periods. The amount of purchased gas costs per Mcf will vary, if appropriate, based upon annual filings pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the PUC's Regulations adopted pursuant thereto.

In the event a Natural Gas Supplier discontinues service or defaults before its contract with the Customer expires, any costs incurred by the Company during the period between the Natural Gas Supplier's discontinuance of service or default and the first day of the Customer's next regular billing cycle which cannot be recovered from the Natural Gas Supplier shall be considered a Purchased Gas Cost.

Definitions

In computing purchased gas costs pursuant to the formula above, the following definitions shall apply:

"PGC" - Purchased Gas Cost determined to the nearest one-hundredth cent (0.01¢) per Mcf to be included in rates for gas supplied under the rate schedules identified above.

"Purchased Gas" - The volume of gas purchased by the Company that is delivered to the Company's Customers, plus such portion of the Company's used and unaccounted-for gas, including, but not limited to, natural gas, synthetic gas, liquefied natural gas, and natural gas substitute, including liquefied propane and naphtha.

"C" - The current cost of gas ("C-Factor") determined as follows: (a) for all types of purchased gas, project the cost for each purchase (adjusted for net current gas stored) for the projected period when rates will be in effect plus (b) the arithmetical sum of (1) the projected book value of noncurrent gas at the beginning of the computation year minus (2) the projected book value of noncurrent gas at the end of the computation year.

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

As applicable, to the extent such charges are not directly paid, Purchased Gas Costs shall include credits related to the use of PGC capacity by transportation customers where the Customer or NGS utilizes Company assigned or released pipeline capacity. In addition, revenues related to balancing services provided pursuant to Sections 22.2 and 22.4; Rate NNS; Rate MBS; capacity or commodity gas sales made pursuant to Customer elections under the Retail Standby Rider; Unauthorized Overrun; OFO, DFD and NGS penalty charges and bundled city gas sales made to NGSs shall be credited to the PGC. Such credits shall be reduced annually by the Economic Benefit Peaking Supply (EBPS Credit)reductions calculated pursuant to Rule 22A.6 of the Rules and Regulations. **(C)**

"E" - Experienced net overcollection or undercollection of purchased gas costs ("E-Factor"). Such net overcollection or undercollection statement shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. Each over-under collection statement shall also provide for refund or recovery of amounts necessary to adjust for over or underrecoveries of E factor amounts under the previous 1307(f)rate.

Interest shall be computed monthly at the rate provided for in Section 1307(f)(5) of the Public Utility Code from the month that the over or undercollection occurs to the effective month such overcollection is refunded or such undercollection is recouped.

Additionally, supplier refunds will be included in the calculation of "E" with interest added at the annual rate of six percent (6%) calculated in accordance with the foregoing procedure, beginning with the month such refund is received by the Company.

Computation and Application of the E-Factor

The E-Factor shall be computed to the nearest one-hundredth cent (0.01¢) per Mcf in accordance with the formula set forth below:

$$\text{E-Factor} = (-E/S)$$

Each E-Factor so computed shall be applied to customer's bill for a one (1) year period during the Computation Year.

"S" - Projected MCF of gas to be billed to Customers during the projected period when rates will be in effect.

(C) Indicates Change

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

Revenue Sharing Incentive Mechanism: The PGC rate determined in this section may be adjusted to reflect the operation of a Revenue Sharing Incentive Mechanism as defined hereafter.

Off-system Sales: If and when the Company makes an off-system sale of natural gas, either in the Company's market area or upstream of the Company's market area with or without the use of PGC assets, the net revenues from the sale shall be shared by both the Company and the Company's retail customers served pursuant to this section of the tariff. The net revenues of the sale shall mean the total revenues from the sale of gas to a third party, less (1) the sum of the cost of natural gas, transportation commodity charges, and fuel retainage, if the sale or exchange is made upstream of the Company's market area or (2) the average city gate commodity cost of all gas purchased and flowing on the first of the month, including the natural gas, transportation commodity, and fuel, if such sale is made at the Company's city gate or in the Company's market area. The sharing of such net revenues shall be allocated in accordance with the Revenue Sharing Allocation procedure in this section.

Exchanges of Natural Gas: If and when the Company and a third party agree to make a location exchange of natural gas in which both parties receive like quantities of gas, with no adverse economic effect on the Company's Customers, any revenues received by the Company for performing this service shall be shared by the Company and the Company's retail Customers served pursuant to this section of the Tariff. Any revenues received from the exchange of natural gas, either upstream of the Company's city gate, or at the Company's city gate, shall be allocated in accordance with the Revenue Sharing Allocation procedure in this Section.

Capacity Release on Interstate Pipelines: Capacity release revenue generated by administrative releases to third parties that fill the Company's storage shall be credited 100% to PGC customers. Other revenue received by the company for off system Capacity Release of interstate pipeline capacity will be credited in accordance with the Revenue Sharing Allocation procedure in this Section.

Storage Asset Management: If and when the Company has a third party manage gas supply assets paid for by the PGC, any revenues received from the third party ("Asset Management Fees") shall be allocated in accordance with the Revenue Sharing Allocation procedure in this Section.

Revenue Sharing Allocation: Effective December 1, 2012, through November 30, 2026 the sum of the revenues derived from all Off-System Sales, Exchanges of Natural Gas, Capacity Release on interstate pipelines and Storage Asset Management, will be allocated 75% to the retail customers served and 25% to the Company. **(C)**

(C) Indicates Change

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

The amount retained by the Company will be an incentive to pursue additional sales and will be treated below the line for ratemaking purposes. For purposes of calculating this margin, the cost of gas will be equal to the monthly average commodity cost of gas plus variable transportation costs to deliver the gas to the off-system customer. The monthly average commodity cost of gas shall be defined as the monthly average commodity cost of gas purchases for all supplies scheduled at the beginning of the month; provided, however, that if an additional unscheduled purchase is made during the month specifically for an off-system sale, such purchase shall be considered to be the gas used to make the off-system sale and the commodity cost of such purchase will be assigned to off-system sales up to the volume of the purchase.

Filing with the PUC: Audit, Rectification

The Company's annual reconciliation statement shall be submitted to the Commission by May 1 of each year, or such other time as the PUC may prescribe.

Quarterly Adjustments

When making the December 1, March 1, June 1 and September 1 quarterly C-factor adjustments, the Company will refund or recover all actual and projected incremental over or under collections from December 1 through November 30 over either remaining PGC year sales volumes or annual PGC year sales volumes. Any quarterly PGC rate change on December 1, March 1 and June 1 will be capped at 25% of the then-current PGC rate, with any amounts above this cap being brought forward for inclusion in the calculation of subsequent quarterly C-factor adjustments. Any quarterly PGC rate change on September 1 will be capped at 15% of the then-current PGC rate, with any amounts above this cap being brought forward for inclusion in the calculation of subsequent quarterly C-factor adjustments.

Rider B – Purchased Gas Cost (Mcf)

Annual C-Factor	$ 5.9486	**(I)**
Annual E-Factor	$ 0.3281	**(I)**
Total Purchased Gas Cost	$ 6.2767	**(I)**

(I) Indicates Increase

RULES AND REGULATIONS

12. RIDER C

EXTENDED TCJA TEMPORARY SURCHARGE

Prior to October 11, 2019:

To implement the effects of the Tax Cuts and Jobs Act (TCJA), on March 15, 2018 the Pennsylvania Public Utility Commission (Commission) issued a Temporary Rates Order at Docket No. M-2018-2641242 directing the utility to file its current base rates and riders as temporary rates, pursuant to Section 1310(d) of the Public Utility Code. 66 Pa. C.S. § 1310(d). Subsequently, on May 17, 2018, the Commission entered an Order superseding the March 15, 2018 Temporary Rates Order directing the utility to establish temporary rates as follows:

A negative surcharge of -4.71%, -2.87%, and -6.34% for the former South, North, and Central Rate Districts, respectively will apply as a credit for intrastate service to all customer bills rendered on and after July 1, 2018. This negative surcharge will be distributed equally among the utility's various customer classes, exclusive of STAS and automatic adjustment clause revenues. **(C)**

This negative surcharge will be reconciled at the end of each calendar year (or fiscal year if not on a calendar year basis) and will remain in place until the utility files and the Commission approves new base rates for the utility pursuant to Section 1308(d) that include the effects of the TCJA tax rate changes.

Interest on over or under collections shall be computed monthly at the residential mortgage lending rate specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, et seq.) from the month that the over or under collection occurs to the mid-point of the recovery period.

Upon determination that the negative surcharge, if left unchanged, would result in a material over or under collection, the Company may file with the Commission, on at least 10 days' notice, for an interim revision of the TCJA Temporary Surcharge.

The TCJA Temporary Surcharge will be filed with the Commission by December 1 of each year to become effective the following January 1.

On and after October 11, 2019: **(C)**

Effective October 11, 2019, the negative surcharge shall be extended ("Extended TCJA Temporary Surcharge") and recalculated only for the purposes of reflecting (a) a credit to customer bills representing the tax benefits of the TCJA for the period January 1, 2018 through June 30, 2018, plus applicable interest computed monthly at the residential mortgage lending rate specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, et seq.) from the month that the TCJA benefit occurred to the mid-point of the refund period for these amounts and (b) within 30 days thereafter, a final reconciliation of any over or under collection of the negative surcharge existing for the period through October 11, 2020.

(C) Indicates Change

RULES AND REGULATIONS

12. RIDER C - Continued

EXTENDED TCJA TEMPORARY SURCHARGE

The Extended TCJA Temporary Surcharge shall be a negative surcharge of -4.72% which will apply as a credit for intrastate service to all customer bills rendered on and after October 11, 2019. This negative surcharge will be distributed equally among the utility's various customer classes, exclusive of STAS and automatic adjustment clause revenues.

The Extended TCJA Temporary Surcharge shall expire October 31, 2020.

Following the expiration date of October 31, 2020, the Extended TCJA Temporary Surcharge shall be reconciled, with interest on the net over or under collection as of November 1, 2020 equivalent to one year (mid-point of return period to mid-point of reconciliation period) being applied at the residential mortgage lending rate specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, et seq.).

On and After November 1, 2020: Extended TCJA Temporary Surcharge

The Extended TCJA Temporary Surcharge shall be 0.00%.

On and After January 1, 2021: Extended TCJA Temporary Surcharge Reconciliation

The Extended TCJA Temporary Surcharge reconciliation shall be -1.23% and shall expire October 10, 2021.

On and After September 9, 2021: Extended TCJA Temporary Surcharge Reconciliation **(C)**

The Extended TCJA Temporary Surcharge reconciliation shall be 0.00% **(I)**

(C) Indicates Change (I) Indicates Increase

RULES AND REGULATIONS

13. RIDER D

MERCHANT FUNCTION CHARGE

Applicability and Purpose

This Rider shall be applied to rates for each MCF (1,000 cubic feet) of gas supplied under Rate Schedules R and N of this Tariff and shall be reflected in the Price to Compare. The Rider is equal to the fixed percentage, established by the PUC in Company's last general base rate proceeding, of purchased gas costs which are expected to be uncollectible, and shall not be reconciled to reflect actual results. Rider D is intended to make Company's Price to Compare more comparable to the gas supply service prices offered of other Natural Gas Suppliers that presumably reflect anticipated uncollectible expenses.

Rider D Charge

Rider D charges shall be equal to 2.17% for Residential PGC Customers and 0.28% **(I)** for Non-Residential PGC Customers of Rider B (Purchased Gas Costs).

The collection of the Rider D charges will be summarized by Rate Schedule sub-accounts in the Gas Operating Revenue FERC Account No. 480000 for Rate R and 481000 for Rates N. The associated costs are recorded in FERC Account Nos. 904001 and 904002.

(I) Indicates Increase

RULES AND REGULATIONS

14. Rider E

GAS PROCUREMENT CHARGE

Applicability

This non-reconcilable Rider shall be applied to rates for each Mcf (1,000 cubic feet) of gas supplied under Rate Schedules R and N of this Tariff and shall be reflected in the Price to Compare. Rider E shall be a volumetric charge as described below and shall remain in effect until reviewed and updated in the Company's next base rate case.

Rider E, or Gas Procurement Charge ("GPC"), recovers costs associated with gas procurement that were unbundled from base rates. The GPC rate is calculated by dividing total unbundled gas procurement costs by the sales volumes for the 12 months ending September 30, 2018, for Rate R and N.

Rider E Charge

Rates: R and N: $ 0.0660 per Mcf

RULES AND REGULATIONS

15. PRICE TO COMPARE

The Price to Compare ("PTC") is composed of the Annual C-Factor, Annual E-Factor, Gas Procurement Charge and Merchant Function Charge. The PTC rate will change whenever any components of the PTC change. The current PTC rate is detailed below:

Price to Compare

	Rate R (CCF)	Rate N (MCF)	
Annual C-Factor	$ 0.59486	$ 5.9486	**(I)**
Annual E-Factor	$ 0.03281	$ 0.3281	**(I)**
Gas Procurement Charge	$ 0.00660	$ 0.0660	
Merchant Function Charge	$ 0.01362	$ 0.0176	**(I)**
Total Price to Compare	$ 0.64789	$ 6.3603	**(I)**

(I) Indicates Increase

RULES AND REGULATIONS

16. RIDER F

UNIVERSAL SERVICE PROGRAM

APPLICABILITY AND PURPOSE

This Rider shall be applicable to all residential customers except customers in the Company's Customer Assistance Program ("CAP"). This Rider has been established to recover costs related to the Company's Universal Service and Conservation Programs, excluding internal administrative costs.

RATE

In addition to the charges provided in this tariff, an amount shall be added to the otherwise applicable charge for each MCF of sales volumes or distribution volumes distributed by the Company to customers receiving service under Rate Schedules R and RT.

The USP rate: $0.3562/Mcf **(D)**

CALCULATION OF RATE

The Rider USP rate shall be calculated to recover costs for the following programs: Low Income Usage Reduction Program (LIURP); Customer Assistance Program (CAP); Hardship Funds; and any other replacement or Commission-mandated Universal Service Program or low-income program that is implemented during the period that the Rider is in effect.

LIURP costs will be calculated based on the projected number of Level 1 income homes to be weatherized. Hardship Fund costs will be calculated on the projected level of an allocated share of administrative funds incurred by the UGI Operation Share Energy Fund.

CAP costs will be calculated to include
1) the projected CAP credit
2) projected CAP customer application and administrative costs; and
3) projected CAP pre-program arrearage forgiveness.

CAP Credit shall be defined as the difference between the total calculated Rate R bill, excluding Rider USP and CAP customer GET Gas charges, and the CAP bill and an adjustment for unearned credit amounts based upon the current discounts at normalized annual volumes of the then-current CAP participants and the projected CAP Credit for projected customer additions to CAP during the period that the CAP Rider rate will be in effect at the average discount of current CAP participants at normalized annual volumes.

(D) Indicates Decrease

RULES AND REGULATIONS

16. RIDER F - Continued

UNIVERSAL SERVICE PROGRAM

QUARTERLY ADJUSTMENT

Any time that the Company makes a change in base rates or PGC rate affecting residential customers, the Company shall recalculate the Rider USP rate pursuant to the calculation described above to reflect the Company's current data for the components used in the USP rate calculation. The Company shall file the updated rate with the PUC to be effective one (1) day after filing.

ANNUAL RECONCILIATION **(C)**

On or before November 1 of each year, the Company shall file with the PUC data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended September. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the CAP quarterly rate adjustment to be effective December 1. Actual recoverable costs shall reflect actual CAP costs, actual application costs, actual pre-program arrearage forgiveness, actual LIURP and actual Hardship Administrative costs. Actual recoverable CAP credit costs and pre-program arrearage forgiveness shall be based upon actual CAP credits granted and pre-program arrearage forgiveness granted less a 9.2% adjustment for amounts granted to participants in excess of 27,287 (the number of CAP enrollees as of September 30, 2020). The 9.2% adjustment related to CAP credits and pre-program arrearage forgiveness will be based on the following:

For each reconciliation period, the average annual CAP credit per participant will be determined by dividing the total actual CAP credits granted during the reconciliation period by the average monthly number of participants receiving CAP credits during the reconciliation period. The average monthly number of participants receiving CAP credits exceeding the number of CAP enrollees as of September 30, 2020 will be multiplied by the average annual CAP credit granted per participant and then multiplied by 0.0920 in order to determine the amount of the CAP Credits which will not be recovered through Rider USP.

For each reconciliation period, the average pre-program arrearage forgiveness per participant will be determined by dividing the total actual pre-program arrearage forgiven during the reconciliation period by the number of participants receiving pre-program arrearage forgiveness. The number of participants receiving pre-program arrearage forgiveness exceeding 27,287 will be multiplied by the average pre-program arrearage forgiveness per participant and then multiplied by 0.0920 in order to determine the amount of the pre-program arrearage forgiveness which will not be recovered through Rider USP.

(C) Indicates Change

RULES AND REGULATIONS

17. RIDER G

ENERGY EFFICIENCY AND CONSERVATION RIDER

Applicability and Purpose

The Energy Efficiency and Conservation Rider (“EEC Rider”) shall recover costs related to the Company’s Energy Efficiency and Conservation Plan (“EECP”). The EEC Rider shall be computed separately for each of the following four customer classes:

1. Residential customers served under Rate Schedules R/RT,
2. Non-Residential customers served under Rate Schedules N/NT,
3. Non-Residential customers served under Rate Schedule DS, and
4. Non-Residential customers served under Rate Schedule LFD.

EEC Rider Rate:

Rate R/RT	$0.2077/Mcf	**(I)**
Rate N/NT	$0.0204/Mcf	**(I)**
Rate DS	$0.0556/Mcf	**(D)**
Rate LFD	$0.0316/Mcf	**(I)**

The EEC Rider shall be subject to the State Tax Adjustment Surcharge.

Calculation

The EEC Rider shall be determined as follows:

1. Costs to be recovered shall include Company incurred costs to implement its Commission approved EECP during each plan year (October 1st through September 30th) (Plan Year), including all costs incurred to develop and administer the Company’s EECP.
2. The Residential EEC Rider shall be calculated in accordance with the formula below and shall be rounded to the fourth decimal:

Residential EEC Rider = (Cr / Sr) – (Er / Sr) where

Cr = Projected Residential EECP Costs.

Sr = Projected Residential Class Sales.

Er = Net over or under collection of the Residential EEC Rider resulting from the difference between the EEC Rider revenues received and the EECP costs incurred.

(I) Indicates Increase **(D) Indicates Decrease**

RULES AND REGULATIONS

17. RIDER G - Continued

ENERGY EFFICIENCY AND CONSERVATION RIDER

3. The Non-Residential EEC Rider shall be calculated in accordance with the formula below and shall be rounded to the fourth decimal:

Non-Residential EEC Rider = (Cn / Sn) – (En / Sn) where

Cn = Projected Non-Residential EECP Costs.

Sn = Projected Non-Residential Class Sales.

En = Net over or under collection of the Non-Residential EEC Rider resulting from the difference between the EEC Rider revenues received and the EECP costs incurred.

4. The Residential and Non-Residential EEC Riders will be updated annually and will be filed with the Commission on one day’s notice to be effective December 1 of each year. The Company reserves the right to make an interim reconciliation filing to adjust the EEC Riders.

5. Any over or under collection at the end of the plan period shall be recovered or refunded either through a subsequent EECP approved by the Commission or through continuation of the EEC Riders until full recovery or refunding has occurred.

RULES AND REGULATIONS

18. RIDER H

TECHNOLOGY AND ECONOMIC DEVELOPMENT RIDER

Availability. The Technology and Economic Development Rider("TED") is a negotiated rider available in the entire territory to Customers served by the Company which the Company determines, in its sole discretion, has prospective additional gas usage applicable to service under Tariff Rate Schedules N, NT, DS or LFD at the time of execution or renewal of a Service Agreement. The Rider TED is established for the purpose of adjusting the customer's overall distribution charge to address project specific or competitive issues to gain access to and expand use of natural gas within the Commonwealth of Pennsylvania. The negotiated Rider TED may be either a surcharge or credit depending on project specific customer and Company economic requirements, such that the overall economics must meet the requirements of Section 5.1 of this Tariff. Rider TED will be utilized to support the expansion of new technologies such as combined heat and power and natural gas vehicles, develop brownfields, and support economic development in Pennsylvania by facilitating business retention and attraction as well as other gas distribution system expansion activities.

General Terms. The Customer must execute a Rider TED service agreement.

MONTHLY RATE TABLE

Monthly Charge:	Negotiable
Plus	
Charge per Mcf:	Negotiable

RULES AND REGULATIONS

19. Rider I

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

In addition to the net charges provided for in this Tariff, a charge of 3.96% will apply. **(I)**

19.A.1 Purpose. To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

19.A.2 Eligible Property.

The DSIC-eligible property will consist of the following:

- Piping, Couplings, Valves, Excess Flow Valves, Risers - Distribution & Transmission. (374, 376, 365, 367)
- Measuring & Regulator Stations – Distribution & Transmission (375, 378, 379, 366, 369, 370)
- Gas Service Lines and Insulated and Non-Insulated Fittings (378, 380)
- Meters, Meter Bars, Meter Installations (381, 382)
- House Regulators & Installations (383, 384)
- Industrial & Farm Tap Measuring & Regulator Station Equipment (385, 386)
- Miscellaneous Equipment and Material– Distribution & Transmission (387, 371)
- Equipment – Electronic Systems & Software (391)
- Vehicles, Power Equipment, Tools, Shop & Garage Equipment (392, 394, 396)
- Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities.
- Gathering lines (332)
- Storage lines (353)
- Other related capitalized costs.

19.A.3 Computation of the DSIC. The DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update.

(I) Indicates Increase

RULES AND REGULATIONS

19. Rider I - Continued

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC-Eligible Plant Additions Reflected
April 1	December 1 through February 28
July 1	March 1 through May 31
October 1	June 1 through August 31
January 1	September 1 through November 30

19.A.4 Determination of Fixed Costs. The fixed costs of eligible distribution system improvements will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.
2. Pre-Tax Return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Utility's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in the last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of the Jurisdictional Utilities released by the Commission.

19.A.5 Application of DSIC. The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service under the otherwise applicable rates and charges, excluding amounts billed for the State Tax Adjustment Surcharge (STAS). To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by the projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of STAS.

Formula: The formula for the calculation of the DSIC is as follows:

$$DSIC - \frac{(DSI*PTRR) + Dep + e}{PQR}$$

Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation.

PTRR = Pre-tax return rate applicable to DSIC-eligible property.

Dep = Depreciation expenses related to DSIC-eligible property.

e = Amount calculated under the annual reconciliation feature or Commission audit, as described below.

RULES AND REGULATIONS

19. Rider I - Continued

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from existing customers plus netted revenue from any customers which will be gained or lost by the beginning of the applicable service period.

Revenues will be determined as one-fourth (1/4) of projected annual revenues as determined in accordance with 19.A.7.5.

19.A.6 Quarterly Updates. Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Audits, Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

19.A.7 Customer Safeguards.

1. Cap: The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.
2. Audit/Reconciliation: The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. § 1350, et seq., shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year or the Company may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year, or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. § 101, et seq.) and will be refunded in the same manner as an over-collection. The Company is not permitted to accrue interest on under collections.
3. New Base Rates: The DSIC will be reset to zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC.
4. Customer Notice: Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change. An explanatory bill insert shall be included with the first billing
5. All Customer Classes: The DSIC shall be applied equally to all customer classes, except that the Company may reduce or eliminate the Rider DSIC to any customer with competitive alternatives who are paying flexed or discounted rates and customers having negotiated contracts with the Company, if it is reasonably necessary to do so.

RULES AND REGULATIONS

19. Rider I - Continued

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

6. Earnings Reports: The DSIC will also be reset to zero, if, in any quarter, data filed with the Commission in the Company’s then most recent Annual or Quarterly Earnings reports show that the Company would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. The Company shall file a tariff supplement implementing the reset to zero due to overearning on one-days’ notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that the Company has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs.

7. Residual E-Factor Recovery Upon Reset to Zero: The Company shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero. The Company can collect or credit the residual over/under collection balance when the DSIC rate is reset to zero. The utility shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Section 19.A.7.2. Once the Company determines the specific amount of the residual over or under collection amount after the DSIC rate is reset to zero, the Company shall file a tariff supplement with supporting data to address that residual amount. The tariff supplement shall be served upon the Commission’s Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the supplement.

RULES AND REGULATIONS

20. Rider J

GAS DELIVERY ENHANCEMENT RIDER

Applicability and Purpose:
The Gas Delivery Enhancement Rider ("GDE") shall provide a mechanism to recover the portion of temporary mobile sources of gas supply and interstate pipeline demand charge enhancements (collectively "GDE Charges") that are incurred to achieve least-cost timely solutions to system reinforcement needs or for pipeline integrity management activities for customers taking service under Rate Schedules:(1) DS and (2) LFD. The allocation of GDE Charges to each of the foregoing Rate Classes will be established by the Company's annual Purchased Gas Cost Proceeding.

GDE Rider Rate:
Rate DS $0.0062 per Mcf (all volumes) **(I)**
Rate LFD $0.0062 per Mcf (all volumes) **(I)**

The GDE Rider shall be subject to the State Tax Adjustment Surcharge.

Calculation of Rate:
The GDE Rider shall be calculated in accordance with the formula below and shall be rounded to the fourth decimal:

$$\text{GDE Rider} = (F + De + Ca + EN)/(Mcf)$$

F = Fixed costs for physical infrastructure required to provide mobile sources of gas supply

DE = Demand enhancement charges

Ca = A commodity adder equal to the difference between the indexed price of natural gas for the affected portion of the service territory and the contracted price of alternative fuel that is used in lieu of natural gas during the system reinforcement.

EN = Net over or under collection of the GDE Rider resulting from the difference between the GDE Rider revenues received and the GDE Rider costs incurred.

Mcf = 1,000 cubic feet of gas supplied under Rate Schedules DS and LFD.

Annual Reconciliation:
In accordance with cost determinations in the Company's annual Purchased Gas Cost filings, GDE Rider costs and revenues will be reconciled on an annual basis that coincides with the Company's Purchased Gas Cost year for the period December 1 through November 30 and will be filed with the Commission on one day's notice to be effective December 1 of each year. Any over or under collection at the end of the period above shall be recovered or refunded through continuation of the GDE Rider until full recovery or refund has occurred.

(I) Indicates Increase

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING

21.1 Company's Right To Reduce or Curtail Service. An emergency exists whenever the aggregate demand for firm service on the Company's system, or confined segment of the system, exceeds or threatens to exceed the gas supply or capacity that is actually and lawfully available to the Company to meet the demands, and the actual or threatened excess creates an immediate threat to the Company's system operating integrity with respect to Priority 1 Customers. In the event of a natural gas emergency, the Company shall have the right to impose a mandatory reduction or curtailment on any Customer's use of gas.

(a) Prior to taking any action under section 21.2 to curtail Customer usage, provided sufficient time exists as determined by the Company in its sole judgement, the Company shall use reasonable efforts and methods to: (1) interrupt all interruptible services, (2) issue Operational Flow Orders or Daily Flow Directives and, (3) call for voluntary usage reductions by any or all Customers.

(b) In planning for natural gas emergency situations, the Company shall make reasonable efforts to make contractual or informal arrangements with Customers and others which would allow the Company to obtain supplies or implement usage reductions in an effort to avoid or mitigate any emergency action pursuant to subsections 21.2 or 21.3 requiring firm service reductions. In making such arrangements, the Company may enter into specific negotiated terms, conditions and rates with any Customer or entity where a clear benefit exists to the Company for the management or avoidance of an emergency. Related costs, if any, may be included as gas costs for recovery under Section 11 of this Tariff.

21.2 Priority-Based Curtailments. In the event of an emergency, where the Company has mandated priority-based curtailments, the available gas supplies to the Company shall be prorated, if practicable, among Customers and NGSs according to the priorities set forth below, listed in descending order. Customers in a higher priority category shall not be curtailed until all Customers falling into a lower priority category have been curtailed to plant protection use levels, unless operational circumstances or physical limitations warrant a different result. Additionally, where only a partial restriction of a category is required, implementation shall be pro rata to the extent practical under the circumstances. Whenever possible, as determined by the Company in its sole discretion, allocation actions shall be limited to confined geographic or operational portions of the Company's system where the emergency exists.

(a) Priority 1. Service for residential and firm critical commercial essential human needs use.

(b) Priority 2. Firm service not included in Priority 1, which for purpose of curtailment shall be prioritized in the following subcategories:

(1) Firm small commercial and industrial service for plant protection under Rates N, NT, and DS.

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING – Continued

(2) Firm large commercial and industrial service for plant protection under Rates LFD and XD.

(3) Firm commercial and industrial service under Rates N, NT, DS, LFD and XD, to the extent actual gas deliveries are being made to the Company's system on behalf of the Customer; all except for plant protection. **(C)**

21.3 Mandatory Reductions. In the event of an emergency under subsection 21.1, the Company may require each commercial and industrial retail and transportation Customer that is not a Priority 1 Customer to reduce its consumption of gas. In requiring mandatory reductions, the gas supplies available to the Company may be allocated to Customers in accordance with the priorities of use specified in subsection 21.2.

(1) The reduction required shall be determined by the Company without regard to priorities of use, as necessary to minimize the potential threat to public health and safety.
(2) The mandatory reduction shall be for a period specified by the Company and may be until further notice. The Company may change a Customer’s authorized usage, upon notice, at any time during an emergency.
(3) Mandatory reductions shall be for a maximum duration of five (5) consecutive business days, unless extended by PUC order.
(4) Except as provided in 21.3(5), the minimum authorized usage may not be lower than the minimum usage of firm service necessary for plant protection use.
(5) When all other service has been curtailed except for Priority 1 service and the Company continues to be unable to meet Priority 1 requirements, the Company shall exercise its judgment as to any further curtailment that may be necessary and shall utilize measures designed to minimize harm to Customers if curtailments to plant protection use are found to be necessary.
(6) Consistent with its responsibility to maintain system integrity at all times, the Company shall provide periodic status updates and restore service as soon as practicable to any gas-fired electric generation facility that is deemed critical to electric system reliability by the electrical system’s control area operator.
(7) Transportation Customers and NGSs are required to deliver, or cause to be delivered, natural gas supplies to the Company’s system during an emergency, regardless of any mandatory gas consumption reductions imposed by the Company on such transportation Customers or NGSs’ Customers. Such natural gas delivery may be required up to the Customer’s or NGS’s applicable DFR, MDQ, DDR or otherwise specified daily delivery quantity as determined by the Company in its discretion.

(C) Indicates Change

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING - Continued

21.4 Notice of Restriction or Curtailment

(a) Notice of any restriction or curtailment shall be made to affected Customers or NGSs via methods and mediums most reasonably expected to accomplish such notice; these may include, but are not limited to: telephone, facsimile, website, or electronic data exchange. If necessary, the Company will make notice through the media in order to communicate specific requests to large groups of Customer categories that are affected, including any relevant geographic limitations.

(b) It is the Customer's or NGS's responsibility to provide the Company with appropriate contact information, and to keep such information updated, in order to assure timely and efficient notices can be provided.

(c) The Company shall endeavor to provide the maximum notice time possible in the event of any notice of restriction or curtailment.

(d) The Company shall provide specific restriction or curtailment notices stating gas usage reduction percentages, absolute usage allowances or other reduction actions. In addition, the Company shall specify compliance timelines and restriction or curtailment durations as appropriate for the circumstance.

21.5 Emergency Allocation. The Company reserves the sole right to authorize exemptions in cases of verified Customer emergency situations affecting health and welfare.

21.6 Definitions

(a) Residential Use - Gas usage in a residential dwelling or unit for space heating, air conditioning, cooking, water heating, or other domestic purposes; all residential Customers served under Rates R, RT, and GL and apartments served under Rate N, NT, and GL, or subsequent rates classified by the Company as residential.

(b) Firm Service – Natural gas service offered by the Company to Customers under Tariffs or contracts that anticipate no interruptions. Such schedules are Rate R, RT, GL, N, NT, DS, LFD, and XD or subsequent firm rate schedules.

(c) Commercial Use – Gas usage by Customers engaged primarily in the sale of goods or services including consumption by office buildings, institutions and government agencies, and classified as commercial class for Company accounting purposes. Commercial Customers are served under Rates GL, N, NT, DS, LFD, XD, and IS or subsequent rates classified by the Company as commercial.

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING – Continued

(d) Essential Human Needs Use - Gas usage into any building where persons normally dwell, including residences, apartment houses, dormitories, hotels, hospitals and nursing homes.

(e) Industrial Use - Gas usage by Customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power and classified as industrial for Company accounting purposes. Industrial Customers are served under Rates GL, N, NT, DS, LFD, XD, and IS, or subsequent rates classified by the Company as Industrial.

(f) Plant Protection Use - Minimum usage of natural gas required to prevent physical harm to an industrial or commercial consumer’s plant facilities or danger to plant personnel at the facility when the protection cannot be afforded through the use of an alternate fuel. Plant protection uses include usage necessary for the protection of the material in process as would otherwise be destroyed, but does not include deliveries required to maintain production.

21.7 Limitation of Liability.

In the event of any limitation of service or curtailment, the Company may restrict, curtail or discontinue service in accordance with this Section 21, or PUC order, without incurring any penalty or liability for any loss, injury or expense that may be sustained by the Customer except when the restriction or discontinuation of service is a result of the Company’s willful or wanton misconduct.

21.8 Appropriation Liability.

(a) The Company may appropriate natural gas and/or pipeline capacity pursuant to this Section 21, a PUC policy statement, directive or order, or an emergency order issued by the Governor of Pennsylvania.

(b) The Company shall compensate the Customer or the Customer’s NGS for the cost of appropriated gas supplies. The compensation, in the aggregate, shall equal but not exceed, the greater of:

(1) the city gate cost of the appropriated natural gas including all transportation charges up to the Company’s city gate; or,

(2) the reasonable cost actually paid by the Customer or the Customer’s NGS for delivered substitute energy, as documented by the Customer or the Customer’s NGS and presented as evidence to the Company. Such compensation may be a later delivery of in-kind gas service at the sole discretion of the affected Customer or NGS.

RULES AND REGULATIONS

21. GAS EMERGENCY PLANNING - Continued

21.9 Discontinuance of Service.

The Company may discontinue service at its sole discretion, without notice, for the duration of an emergency, to any Customer that continues to take gas in violation of any rules, notice of limitation or curtailment provided for under this Section 21.

21.10 Penalties for Unauthorized Takes.

(a) The Company may, in its sole discretion, issue penalties for any unauthorized taking of gas to any Customer failing to comply with any restriction or curtailment made under this Section 21.

(b) The penalty for unauthorized takes associated with this section shall be equivalent to those for a Critical Day in Section 22.4 General Terms for Delivery Service For Rate Schedules DS, LFD, XD, and IS - Maximum Daily Excess Balancing Charge. Payment of penalties under this section shall be in addition to any liability for direct or indirect damages resulting from Customer’s or Customer’s NGS failure to comply.

(c) The Customer shall be liable to the Company for any costs incurred in taking action to discontinue service in accordance with actions taken under subsection 21.9.

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RULES AND REGULATIONS

22A. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS
Effective November 1, 2020 (C)

22A.1 Application of Rates

(a) Applicable Rates: DS, LFD, XD and IS.

(b) Notification of Delivery; Nomination Procedures. Customer shall notify the Company of any and all gas deliveries to the Company's system, including, but not limited to, the provision of nomination, revised nomination and scheduling information, in accordance with the Company's *Nomination Procedure*, as may be amended from time to time, and made available on the Company’s Gas Management Website (“Nomination Procedure”). The quantity of gas received on behalf of the Customer shall be determined by allocation or other method by the Company if required in its sole discretion. It is the Customer's responsibility to arrange that any necessary billing information be provided to the Company and/or delivery gas source.

(c) Nominating Agents. A Customer shall notify the Company of its designated nominating agent (“Agent”) for purposes of nominating the volumes of natural gas to be delivered to the Company’s system on the Customer’s behalf in accordance with the Nomination Procedures. Customer shall notify Company, on a form designated by the Company in the Nomination Procedures, of the responsibilities of the Agent, and shall provide Company with the Agent’s valid e-mail address and valid 24-hour contact information. Customer shall remain liable for all charges and penalties notwithstanding Customer’s designation and use of an Agent in accordance with the provisions herein.

(d) Penalties for Customer’s Default. Customers failing to provide nomination, billing, scheduling, agent, supplier and/or other required information to the Company or pipeline(s)in accordance with the provisions of the Tariff, or otherwise failing to comply with the Company's *Nomination Procedure*, shall be subject to applicable imbalance charges and, in addition, be charged an Administrative Scheduling Fee in an amount no greater than $1,000 per day for every day such required information is delayed. If a Customer default of these provisions occurs and is occurring for a period of 90 days, the Company may impose retail or standby rates on the Customer’s account beginning the first day after such 90-day period through and until such time as the Company deems the Customer default to have been resolved.

(e) Sequencing for Billing. Unless otherwise agreed by the Company and the Customer, customer-owned gas delivered under the transportation rate schedules shall be sequenced for billing as the first gas through the meter, and gas purchased under the Retail and Standby Rider shall be sequenced for billing purposes as the last gas through the meter. Gas billed under firm rate schedules shall be billed prior to gas billed under interruptible rate schedules. In lieu of otherwise specified tariff provisions, where the Company and Customer agree, Company shall use pipeline metering facilities for measuring and billing total deliveries to the Customer's facility.

(C) Indicates Change

RULES AND REGULATIONS

22A. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

(f) Payment of Charges, Penalties. The Customer shall pay the Company for any and all additional charges incurred on the Customer's behalf or resulting from the Customer's actions or inactions which the Company can demonstrate arise out of the provision of transportation service including, but not limited to, pipeline transportation and service charges. Any such charge, penalty or obligation imposed by a pipeline transporter or supplier as result of balancing of gas delivered to the Customer shall be paid by the Customer in addition to otherwise applicable charges.

(g) The Billing Pool Agent is required to notify Company at least ten days prior to dropping a Customer from a Billing Pool. If adequate advance notice is not provided, the Company reserves the right to not drop the Customer from the Billing Pool.

(h) Billing Pools. One or more transportation Customers may join together in pooled transactions for the purchase and delivery of gas. The Company may allocate among all such customers the volumes of gas or imbalances for purposes of determining responsibility for charges, rates, penalties or other obligations imposed by the Company, or in connection with operation of the pool. A Supplier to a Billing Pool must notify the Company prior to initiating gas deliveries. A Customer is required to submit in writing a request for entry into a Billing Pool.

(1) Each Billing Pool shall appoint an Agent who will coordinate nomination, billing, reconciliation, allocation and any other necessary communication between the Billing Pool and the Company.

(2) All members of a Billing Pool shall be of like balancing service election. The Company may restrict formation or operation of any Billing Pool in order to meet like balancing service election or pipeline imposed eligibility requirements.

(3) Automated Meter Reading. The Company has the right as a condition of being a pool member, to install, at the Customer’s expense, automated meter reading (“AMR”) equipment for the purposes of daily collection or monitoring, and billing Customer volumes at each related service meter. Where AMR equipment is installed, the Customer shall maintain, at its expense, unless otherwise directed by the Company, a dedicated phone connection and electric service to the AMR equipment which will allow the Company unlimited remote access to the AMR device at all times. Failure to maintain a required phone and/or electric service may result in Customer being removed from a Billing Pool and being placed on a rate schedule not requiring daily measurement capability.

(4) Service under Rate NNS is required by, and shall be individually billed to, any and all members of a Billing Pool except when all pool members are monitored on a daily basis through the use of Company owned AMR equipment at all meter locations. Additionally, service under Rate MBS is required by, and shall be individually billed to, any and all members of a Billing Pool when the billing month for each pool member does not end on the same calendar date; Billing Pools having all customers monitored and billed through the use of Company owned AMR equipment at all meter locations shall be exempt from this requirement.

(C) Indicates Change

RULES AND REGULATIONS

22A. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued

(i) Recognition of Supplies. Volumes transported on behalf of the Customer will be recognized in the Customer's current billing month based on nominated or scheduled volumes information and may be adjusted after notification is received from the pipeline supplier(s) of the volumes transported on behalf of the Customer. Volumes scheduled shall be determined on the basis of best available actual or confirmed pipeline and/or Company information at the time of billing.

(j) Unless otherwise negotiated under Rate XD, the Company shall retain for Company use gas, and lost and unaccounted for gas, 1.0% of the total volume of gas delivered into its system for the Customer's account. **(D)**

22A.2 Balancing and No-Notice Service.

(a) Each Customer shall use best efforts to balance purchases, deliveries and receipts of gas at all times. Except as specified in 22.1(f), for the purposes of balancing excess deliveries and shortfalls and purchasing services under Rates NNS and MBS, Billing Pools may be treated as a single entity. Subject to the terms and conditions set forth below, the Company shall provide no-notice and monthly balancing services under Rate Schedules NNS and MBS. Service under Rate Schedules NNS and MBS is available only for inadvertent fluctuations, limited by the terms and conditions of each Rate Schedule, and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided. In the event the Customer fails to use best efforts to balance deliveries and receipts, or otherwise misuses no-notice or balancing services as determined by the Company in its sole discretion, Section 22.4 shall apply for the period of such default or misuse.

(b) Daily Balancing. The Company shall allow Customer's daily demand to inadvertently vary from daily scheduled deliveries by +/-4.5% without imposing Daily Balancing Charges, provided the total daily quantity taken does not exceed Customer's Daily Firm Requirement, MDQ or otherwise specified contract demand limit. Daily imbalances in excess of the +/-4.5% tolerance, unless otherwise provided by service elected under Rate NNS, shall be assessed a Maximum Daily Excess Balancing Charge in accordance with Section 22.4 under Critical Day and Non-Critical Day criteria unless otherwise specified in Customer's contract, in addition to the charges specified in Rates DS, LFD, XD and IS, on all such quantities.

(c) Imbalance Resolution. Customer's monthly imbalances will be calculated at the end of each billing period to determine if any overdelivery (excess) or underdelivery (shortfall) condition exists for volumes scheduled versus volumes metered. If the Customer is determined to be in an imbalance condition, and has not elected service under Rate MBS or has exceeded the 10% imbalance allowance provided under Rate MBS, then the Company shall sell and the Customer shall buy, subject to the 5 percent limitation under Rate MBS, any shortfall amount according to the following cash-out pricing:

(D) Indicates Decrease

RULES AND REGULATIONS

22A. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

Shortfall Percent	Cash-Out Price
Up to 5%	Shortfall Monthly Index(“SMI”)
Greater than 5%, but not greater than 15%	SMI x 1.1
Greater than 15%, but not greater than 25%	SMI x 1.3
Greater than 25%	SMI x 1.5

Likewise, the Customer shall sell, and the Company shall buy any excess amount according to the following cash-out pricing:

Excess Percent	Cash-Out Price
Up to 5%	Excess Monthly Index (“EMI”)
Greater than 5%, but not greater than 15%	EMI x 0.9
Greater than 15%, but not greater than 25%	EMI x 0.7
Greater than 25%	EMI x 0.5

The SMI (Shortfall Monthly Index) shall be the average of the published *Gas Daily* Midpoint index prices corresponding to the Customer’s Delivery Region during the Customer’s billing month as listed below:

Delivery Region	**Index**
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The EMI (Excess Monthly Index) shall be the average of the published *Gas Daily* Midpoint index prices corresponding to the Customer’s Delivery Region during the Customer’s billing month as listed below:

Delivery Region	**Index**
North	Tennessee, zone 4-300 leg
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C) Indicates Change

RULES AND REGULATIONS

22A. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

Customer Delivery Region shall be assigned to each Customer in accordance with Customer's delivery location within the Company's distribution system.

The SMI and EMI are applicable to the above tables only for inadvertent monthly imbalances. The HMI (Highest Monthly Index) or the LMI (Lowest Monthly Index) as defined below shall apply respectively to shortfall and excess conditions in those situations where intentional imbalances are involved.

The HMI shall be calculated as the highest of the published *Gas Daily* Absolute index prices for the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	**Index**
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The LMI shall be calculated as the lowest published *Gas Daily* Absolute prices for the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	**Index**
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C) Indicates Change

RULES AND REGULATIONS

22A. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

(d) The Company may extend the balancing period for gas volumes and may increase volumes eligible for balancing in its discretion, but only if it determines that such action is consistent with its obligations to other customers.

(e) Supply Transfers. In order to facilitate Monthly balancing related to inadvertent imbalances in Company's sole discretion, the Company shall allow Supply Transfers among Customers and Billing Pools, Customers-to-Billing Pools and Billing Pools-to-Customers at a fee of $125 per transaction, provided however: (1) such transfer is requested prior to the end of the billing month for both the transferee and the transferor, (2) such transfer is physically possible given pipeline interconnection and delivery point limitations which require transfers to be between parties located on the same segment of the Company's distribution system, and system supplies, and reliability are not adversely affected.

(f) Competitive Volume Customers. In the case of Customers or applicants seeking service for facilities with a design volume capability allowing for direct connection to transmission or gathering lines for bypass of Company facilities, Company shall have the right to establish daily and monthly balancing tolerances at levels other than those specified in subsections (b) and (c) of this Section 22.2 to reflect specific operational limitations or to protect the interests of other Customers, as determined by the Company in its sole discretion. Additionally, the Company may establish special nomination rules, imbalance resolution rules and communication protocols that reflect the Customer's or applicant's commercial alternatives, and which are consistent with its obligations to other Customers.

22A.3 Service Agreement and General.

(a) Limitation on Liability.

(1) The Company shall not be liable for curtailment of service under Rates DS, LFD, XD and IS, or loss of the Customer's gas as a result of any steps taken to comply with any law, regulation or order of any governmental agency with jurisdiction to regulate, allocate or control gas supplies or the rendition of service hereunder, and regardless of any defect in such law, regulation or order.

(2) Gas transported and delivered by the Company to the Customer hereunder shall be and remain the property of the Customer. The Customer shall be responsible for maintaining all insurance it deems necessary to protect its property interest in such gas before, during and after receipt by the Company.

(3) The Company shall not be liable for any loss to the Customer arising from or out of service hereunder, including loss of gas in the possession of the Company or any other cause, except gross or willful negligence of the Company's own employees or agents. The Company reserves the right to commingle gas of the Customer with other supplies.

(C) Indicates Change

RULES AND REGULATIONS

22A. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

(b) Warranty, indemnity and special provisions. The receipt of service constitutes Customer's agreement to the following representations and warranties, together with related provisions in the service agreement:

(1) clear and marketable title to the Customer's gas;
(2) delivery points, pressure, quality and other specifications acceptable to gas transmission pipeline(s) and the Company;
(3) eligibility of the Customer for service;
(4) existence of lawful authority for sale, transportation and delivery;
(5) agreement to pay all excise, sales, use, gross receipts, or other taxes (other than income taxes), all tariff charges and all penalties, charges, fees for transportation, balancing etc., associated with delivered gas, which may be levied upon or incurred by the Company at any time;
(6) agreement to indemnify and hold the Company harmless from breach of representations or warranties, and any liability associated with Customer's gas while on the Company's system.

Copy of Gas Purchase Agreements, Other Documents. When requested by the Company, the Customer shall provide the Company with a copy of Customer's gas purchase contract and any related transportation, marketing and brokerage contracts, or, in lieu of providing such contracts, certify pertinent information as required by the Company, and, in order to meet state or federal requirements, provide a sworn affidavit setting forth the Customer's cost of gas for the period requested by the Company. The Company shall endeavor to protect the confidentiality of information provided by the customer in accordance with this provision. The Company will provide such information to third parties only when required to do so by law, regulation or order and in such case, will attempt to maintain confidentiality to the extent possible.

22A.4 Maximum Daily Excess Balancing Charge

The Daily Excess Balancing Charge that occurs on Critical Days shall be as follows:

The charge for exceeding daily balancing limits shall be ten times the highest price as published in *Gas Daily* on the table “Daily Price Survey.” For each delivery region as listed in the table below. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into Pennsylvania.

(C) Indicates Change

RULES AND REGULATIONS

22A. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

Delivery Region	Index
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.
Central	The higher of 1) Transco, zone 6 non-N.Y. or 2) Transco, Leidy Line receipts plus the applicable transportation costs from Transco Zone 6 to Zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The Daily Excess Balancing Charge that occurs on Non-Critical Days shall be as follows:

Daily Imbalance Percent	Penalty
Up to 15%	GDI
Greater than 15%, but not greater than 30%	GDI x 2
Greater than 30%, but not greater than 45%	GDI x 3
Greater than 45%, but not greater than 60%	GDI x 4
Greater than 60%	GDI x 5
Intentional imbalances	GDI x 5

The GDI (Gas Daily Index) shall be equal to the difference in price between the highest published *Gas Daily* index price and the lowest published *Gas Daily* index price for the Customer's Delivery Region as listed below but shall not be lower than $0.25/Mcf.

Delivery Region	Highest Index Price	Lowest Index Price
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.	Tennessee, zone 4- 300 leg
Central	Transco zone 6, non-N.Y.	Transco, Leidy line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C) Indicates Change

RULES AND REGULATIONS

22A. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

The Company shall not charge any Maximum Daily Excess Balancing Charges if the Customer's Excess Daily Imbalance is anticipated to benefit the distribution systems daily balancing position as determined by Company in its sole discretion.

22A.5 Operational Flow Orders and Daily Flow Directives

The Company has the right to issue Operational Flow Orders and Daily Flow Directives at any time. Failure to comply with any OFO or DFD shall result in a penalty charge of Twenty-Five ($25) per Mcf or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater.

22A.6 Cost of Assigned Capacity.

In addition to applicable interstate pipeline demand charges, the associated demand charges to customers, or their NGS, served under Rates DS and LFD, and who utilize assigned PGC capacity, will include 100% and 50% pro rata allocation of annual Peaking Supply service demand costs, respectively. The associated demand charges will be reduced by a pro rata share of the Economic Benefit of Peaking Supply (EBPS Credit). The EBPS Credit shall mean a pro rata share of (a) the value of Peaking Supply utilized in off system sales transactions and included in the PGC share of the Revenue Sharing Incentive Mechanism revenues, plus (b) the Commodity Price Differential, which shall be, as measured for the date of Peaking Supply delivery, the aggregate difference, if positive, between the Gas Daily price applicable to the zone of delivery (i.e., Texas Eastern M3 for deliveries in the South and West Delivery Regions with the exception of deliveries from Mt. Bethel and Transco Z6 NNY for deliveries made in the North and Central Delivery Regions and deliveries from Mt. Bethel) and the actual price paid for actual Peaking Supply deliveries into the UGI distribution system. The EBPS Credit shall be applied in the calculation of associated demand charges in the second billing month after the credit has accrued (e.g., December accrued credits will be used to reduce the February associated demand charges) and shall not, on an annual basis, exceed the annual incremental demand charges for Peaking Services charged to Rate DS and LFD customers, or their NGS, as described above.

(C) Indicates Change

RULES AND REGULATIONS

23. GENERAL TERMS FOR INTERCONNECTION COORDINATION SERVICES FOR CONNECTING ENTITIES

Any entity with actual or potential sources of gas supply connected to Company facilities (Connecting Entity) shall be obligated to enter into an agreement with the Company (Coordination Agreement) addressing, to the extent applicable: (1) the duties and obligations of the parties with respect to their respective facilities, (2) measurement of deliveries of gas, (3) gas quality standards, (4) nomination requirements, (5) permitted variations in supply deliveries and imbalance resolution and (6) other operational issues raised by the nature of the supply source connection

RULES AND REGULATIONS

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RULES AND REGULATIONS

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RATE R

GENERAL SERVICE – RESIDENTIAL

AVAILABILITY

This rate applies to all Residential Customers in the entire gas service territory of the Company and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company's gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $14.60 per customer effective through Sept. 30, 2021 **(C)**
$15.31 per customer effective Oct. 1, 2021 – Sept. 30, 2022 **(C, I)**
$14.60 per customer effective on and after Oct. 1, 2022 **(C, D)**

Plus Distribution Charge:
$0.37861/Ccf effective through December 31, 2020 **(C)**
$0.39464/Ccf effective January 1, 2021 – June 30, 2021 **(C, I)**
$0.41104/Ccf effective on and after July 1, 2021 **(C, I)**

Plus SURCHARGES and RIDERS
- Rider A – State Tax Adjustment Surcharge
- Rider B – Section 1307 (f) Purchased Gas Cost
- Rider C – Extended TCJA Temporary Surcharge
- Rider D – Merchant Function
- Rider E – Gas Procurement Charge
- Rider F – Universal Service Program
- Rider G – Energy Efficiency and Conservation
- Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT

In accordance with Section 8.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(I) Indicates Increase (C) Indicates Change (D) Indicates Decrease

RATE RT

GENERAL SERVICE – RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies to all Residential Customers in the entire gas service territory who are served by a qualified Choice Supplier receiving service under Rate AG and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company's gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $14.60 per customer effective through Sept. 30, 2021 **(C)**
$15.31 per customer effective Oct. 1, 2021 – Sept. 30, 2022 **(C, I)**
$14.60 per customer effective on and after Oct. 1, 2022 **(C, D)**

Plus Distribution Charge:
$0.37861/Ccf effective through December 31, 2020 **(C)**
$0.39464/Ccf effective January 1, 2021 – June 30, 2021 **(C, I)**
$0.41104/Ccf effective on and after July 1, 2021 **(C, I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C – Extended TCJA Temporary Surcharge
Rider F - Universal Service Program
Rider G – Energy Efficiency and Conservation
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase (C) Indicates Change (D) Indicates Decrease

Rate RT - Continued

GENERAL SERVICE – RESIDENTIAL TRANSPORTATION

PAYMENT

In accordance with Section 8.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

RULES AND REGULATIONS

Where a Customer is returned to the Company or an alternate Supplier of Last Resort prior to the next regular meter reading date, due to the Licensed Choice Natural Gas Supplier's non-performance, Customer will receive service from Company or alternate Supplier of Last Resort for the remainder of the billing month at the contract rate between the Customer and Choice Supplier. Customer must provide evidence of the applicable contract rate, if requested by Company, to receive the contract rate price. As of the next regular meter read date, Customer will be transferred to Rate R, unless enrolled as a Rate RT customer by another Choice Supplier, effective as of the next regular meter read date.

GENERAL TERMS

Company Use and Unaccounted For gas shall be retained in accordance with Section 5, Operational Requirements, paragraph 5.1, Daily Delivery Requirements, of the Gas Choice Supplier Tariff.

RATE GL

GENERAL SERVICE - GAS LIGHT SERVICE

AVAILABILITY

This service is available for street, highway, driveway or other lighting or sign illumination, where measurement by meter of the gas consumed is not practicable or economical. As used herein, "light" means a single lamp or sign having one (1) gas-flow orifice and one (1) or more mantles, and of a type approved by the Company.

MONTHLY RATE TABLE

Distribution Charge:
$0.37861/Ccf effective through December 31, 2020 **(C)**
$0.39464/Ccf effective January 1, 2021 – June 30, 2021 **(C, I)**
$0.41104/Ccf effective on and after July 1, 2021 **(C, I)**

Plus

SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider B – Section 1307(f) Purchased Gas Cost
Rider C – Extended TCJA Temporary Surcharge
Rider I – Distribution System Improvement Charge

Monthly usage is assumed to be 1.8 Mcf, however, for larger consumption input fixtures, the Company reserves the right to modify

BILLS DUE

All bills for continuing service are due each month when rendered, and the final due date stated on the bill shall be no less than fifteen (15) days from the date of presentation. Upon discontinuance of service, bills are due and payable upon presentation.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

SPECIAL TERMS AND CONDITIONS

Gas will be supplied to lights furnished, erected and maintained by the customer only when equipped with regulators and such devices as the Company considers necessary for turning lights on and off for maintenance and safety purposes.

(I) Indicates Increase (C) Indicates Change

RATE N

GENERAL SERVICE – NON-RESIDENTIAL

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Non-Residential Customers, using gas for any purpose including gas purchased by another public utility for resale. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate N service may not be applied to supplement or back up any transportation service.

MONTHLY RATE TABLE
Customer Charge: $23.50 per customer effective through Sept. 30, 2021 **(C)**
$24.75 per customer effective Oct. 1, 2021 – Sept. 30, 2022 **(C, I)**
$23.50 per customer effective on and after Oct. 1, 2022 **(C, D)**
Plus Distribution Charge: **(C, I)**

	Former South/Central Districts	Former North District
Effective through December 31, 2020	$3.5177/Mcf	$3.1559/Mcf
Effective Jan. 1, 2021 – June 30, 2021	$3.5719/Mcf	$3.2101/Mcf
Effective on and after July 1, 2021	$3.6271/Mcf	$3.2653/Mcf

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider B - Section 1307(f) Purchased Gas Cost
Rider C – Extended TCJA Temporary Surcharge
Rider D – Merchant Function Rider
Rider E – Gas Procurement Charge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE
The Customer Charge as set forth above.

MINIMUM BILL PROVISION
If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT
In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(I) Indicates Increase (C) Indicates Change (D) Indicates Decrease

RATE NT

GENERAL SERVICE – NON-RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Customers who are served by a Choice Supplier receiving service under Rate AG, except residential Customers, using gas for any purpose. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate NT service may not be applied to supplement or back up any transportation or retail service.

MONTHLY RATE TABLE

Customer Charge: $23.50 per customer effective through Sept. 30, 2021 **(C)**
$24.75 per customer effective Oct. 1, 2021 – Sept. 30, 2022 **(C, I)**
$23.50 per customer effective on and after Oct. 1, 2022 **(C, D)**

Plus Distribution Charge: **(C, I)**

	Former South/Central Districts	Former North District
Effective through December 31, 2020	$3.5177/Mcf	$3.1559/Mcf
Effective Jan. 1, 2021 – June 30, 2021	$3.5719/Mcf	$3.2101/Mcf
Effective on and after July 1, 2021	$3.6271/Mcf	$3.2653/Mcf

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C – Extended TCJA Temporary Surcharge
Rider G – Energy Efficiency and Conservation
Rider H - Technology and Economic Development
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

The Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase (C) Indicates Change (D) Indicates Decrease

RATE NT – Continued

GENERAL SERVICE – NON-RESIDENTIAL TRANSPORTATION

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

RULES AND REGULATIONS

Where a Customer is returned to the Company or an alternate Supplier of Last Resort prior to the next regular meter reading date, due to the Licensed Choice Natural Gas Supplier's non-performance, Customer will receive service from Company or alternate Supplier of Last Resort for the remainder of the billing month at the contract rate between the Customer and Choice Supplier. Customer must provide evidence of the applicable contract rate, if requested by Company, to receive the contract rate price. As of the next regular meter read date, Customer will be transferred to Rate N, unless enrolled as a Rate NT customer by another Choice Supplier, effective as of the next regular meter read date.

GENERAL TERMS

Company Use and Unaccounted For gas shall be retained in accordance with Section 5, Operational Requirements, paragraph 5.1, Daily Delivery Requirements, of the Gas Choice Supplier Tariff.

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(C) Indicates Change

PAGE INTENTIONALLY LEFT BLANK **(C)**

(C) Indicates Change

RATE DS

DELIVERY SERVICE

AVAILABILITY

This service applies in the entire territory served by the Company. Firm Delivery Service shall be provided for all volumes supplied by the Customer for which the Company has available on system delivery capacity, subject to Section 21 - Gas Emergency Planning provisions of the Company's tariff, applicable rules and regulations of the PUC and any other governmental mandates.

The Customer must execute a Service Agreement for not less than (1) one year. The contract shall continue in force for consecutive (1) year periods unless cancelled by the Customer upon ninety (90) days written notice to Company prior to the expiration of a contract term.

Gas service in excess of volumes delivered by the Customer shall only be provided in accordance with applicable delivery service balancing provisions or in accordance with optionally elected and approved balancing or standby services.

Service under Rate DS is subject to the terms set forth under Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Capacity Charge if applicable, and the Distribution Charge as described below. The following are maximum rates.

Customer Charge: $260.00 per month effective through Sept. 30, 2021
(C)
$263.24 per month effective Oct. 1, 2021 – Sept. 30, 2022 **(C, I)**
$260.00 per month effective on and after Oct. 1, 2022 **(C, D)**

Plus Capacity Charge: The Company's unitized weighted average cost of firm transportation capacity per elected MDQ.

Plus Maximum Distribution Charge: **(C, I)**

	Former South/Central Districts	Former North District
Effective through Dec. 31, 2020	$2.9550/Mcf	$2.1335/Mcf
Effective Jan. 1, 2021 – June 30, 2021	$2.9640/Mcf	$2.1425/Mcf
Effective on and after July 1, 2021	$2.9730/Mcf	$2.1515/Mcf

Plus

SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C – Extended TCJA Temporary Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

(I) Indicates Increase (C) Indicates Change (D) Indicates Decrease

RATE DS – Continued

DELIVERY SERVICE

MINIMUM BILL

Monthly: The Minimum Monthly Bill shall be the Customer Charge and the Capacity Charge. **(C)**

The MDQ shall be the Company's contracted maximum firm delivery obligation to the Customer on any day. Service in excess of the MDQ is interruptible in accordance with the terms of Rate IS. **(C)**

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

RETAINAGE RATE

Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, AND IS, paragraph 22.1(j).

(C) Indicates Change

RATE NNS

NO-NOTICE SERVICE

AVAILABILITY

This Rate is available upon request to any Customer served on Rate DS, LFD, XD or IS who, after review and acceptance of such request by Company, has entered into a service agreement with Company for service under Rate NNS. The term of the service agreement shall be concurrent with that of the Customer's underlying Delivery Service Schedule.

Service under this Rate is available for inadvertent fluctuations only and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided.

Service to large volume users, such as electric generation facilities, may be limited as determined by the Company. Service under Rate NNS is subject to the terms and conditions set forth under Section 22 General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

TERMS AND CONDITIONS **(C)**

Customers shall elect a specific level of no-notice service under this Rate. Such election shall be made through the specification of a No-Notice Allowance ("NNA"), in MCF per day, of an amount no less than by 10.0% (former South Rate District) and 2.5% (former North and Central Rate Districts)and no greater than 100% of Customer's Daily Firm Requirement, Maximum Daily Quantity or otherwise specified daily contract limit. After November 1, 2020, the minimum election of NNA in MCF per day shall be no less than 4.5% and no greater than 100% of Customer’s Daily Firm Requirement, Maximum Daily Quantity or otherwise specified daily contract limit. The elected NNA shall be effective for a fixed period equal to the lesser of one year or the remaining balance of the Customer's service agreement or, a lesser time period mutually agreeable to both the Customer and the Company. In no instance shall a NNA be effective for a period of less than one month. Rate NNS service elections in excess of 10.0% (former South Rate District) and 2.5% (former North & Central Rate Districts), or after November 1, 2020, 4.5%, are interruptible.

No-notice service shall be provided under this Rate whereby the Company shall forward or bank no-notice supplies to the Customer on a daily basis in such amounts necessary to balance the Customer's daily deliveries with the Customer's daily consumption. Forwarded amounts shall be limited in amount by the lesser of the sum of the Customer's daily nomination plus elected NNA or, the Customer's DFR, MDQ or otherwise specified contract limit except as allowed. Banked amounts shall be limited to an amount no greater than the Customer's NNA election.

Customer electing an NNA shall be billed for no-notice service according to that specific level of service.

Volumes in excess of the daily limits shall be subject to Daily Excess Imbalance Charges as set forth in Section 22.4 General Terms For Delivery Service for Rate Schedules DS, LFD, XD and IS on all such excess quantities, in addition to the charges specified in the Customer's Delivery Service Schedule.

(C) Indicates Change

RATE NNS - Continued

NO-NOTICE SERVICE

EXCESS REQUIREMENT OPTION

The Excess Requirement Option is available on an interruptible basis to any delivery service Customer served under Rates XD, LFD. This Option shall extend the no-notice provisions of Rate NNS, on solely a best efforts basis, during periods where Customer's daily requirements exceed transportation contract service limits.

Customer must nominate a Daily Excess Requirement ("DER") under this Option in an amount no less than 5 Mcf per day and no greater than 25% of Customer's DFR or otherwise specified contract limit. On days where service under the Excess Requirement Option is required, Customer will have the right, subject to the terms and conditions set forth herein, to take gas in excess of Customer's DFR or otherwise specified contract limit provided such excess is no greater than the nominated DER amount.

Service taken in excess of the sum of Customer's DFR and DER on any day shall be considered Excess Take or Unauthorized Overrun as determined by Customer's Delivery Service Schedule and service agreement.

Unauthorized gas forwarded or returned to the Company by the Customer shall be considered imbalance gas and shall be subject to either the balancing provisions set forth under Section 22.2 of General Terms for Delivery Service for Rate Schedules DS, LFD, XD and IS or the Customer's otherwise applicable transportation balancing service.

MONTHLY RATE TABLE (Basic NNS Service)

$0.0244 per Mcf **(C)**

or, if applicable $0.4880 per Mcf per day of elected NNA **(C)**

plus

MONTHLY RATE TABLE (Excess Requirement Option)

$4.50 per Mcf per day of elected DER.

(C) Indicates Change

RATE MBS

MONTHLY BALANCING SERVICE

AVAILABILITY

This Rate is available upon request to any Customer served on Rate DS, LFD, XD or IS who, after review and acceptance of such request by Company, has entered into a Service Agreement with Company for service under Rate MBS. The term of the Service Agreement shall be concurrent with that of the Customer's underlying Rate Schedule.

Service under Rate MBS is available for inadvertent fluctuations only, limited to an amount not to exceed 10% of the customer's total scheduled deliveries for the month, and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided. Service under Rate MBS is subject to the terms set forth in Section 22 General Terms For Delivery Service for Rate Schedules DS, LFD, XD, and IS.

Rate MBS is available as a monthly banking service for Customer transportation deliveries. Service under Rate MBS allows Customer transportation imbalances (metered volumes less total scheduled nominations) which are within 10% of Customer's total scheduled nominations for the month to be carried forward in the Customer's MBS Account ("Balance Account") for redelivery of excesses or receipt of shortfalls in subsequent months.

TERMS AND CONDITIONS

Balance Account Operation. To the extent Customer's total deliveries exceed Customer's total consumption at the end of a Billing Month, the excess volumes shall be added to the Customer's Balance Account. To the extent Customer's total consumption exceeds Customer's total deliveries at the end of a Billing Month, the shortfall volumes shall be subtracted from the Customer's Balance Account.

Balance Account Limits. At no time, as calculated at the end of a Billing Month, shall a Customer exceed a Balance Account excess or shortfall balance greater than 10% of the Customer's total scheduled deliveries for the month, as determined by the Company in its sole discretion. Any such imbalance on the Customer's Balance Account shall result in an immediate zeroing of the Balance Account balance. Effective November 1, 2020, any such imbalance over 10% (excess or shortfall) shall **(C)** be subject to the Cash-in/Cash-out pricing set forth in Section 22A.2 for monthly imbalance volumes in excess of 5%, with the remaining imbalance volumes to be carried over into the calculation of the Customer’s imbalance volumes for the following month.

The Company, in its sole discretion, may zero out the Customer's Balance Account at the end of any Billing Month by purchasing or selling such net imbalance volumes in the Customer's Balance Account at the prevailing month's Cash-In/Cash-Out pricing at set forth in Section 22.2, provided such zero out may occur only if necessitated by operational needs of the Company or as a result of a requirement of an applicable interstate pipeline.

(C) Indicates Change

RATE MBS - Continued

MONTHLY BALANCING SERVICE

MONTHLY RATE TABLE

Monthly Transportation Volume

Rate DS/IS	$0.0277/Mcf x Monthly Billed Volumes	**(I)**
Rate LFD	$0.0160/Mcf x Monthly Billed Volumes	**(I)**
Rate XD	$0.0165/Mcf x Monthly Billed Volumes	**(I)**

The Company will update the average monthly imbalance utilized in the development of Rate MBS charges annually with the actual average monthly imbalance for the 12-month period ending September to determine the new Rate MBS charges effective December 1 each year. The Company shall include the new Rate MBS charges as part of its annual PGC compliance filing.

(I) Indicates Increase

RATE LFD

LARGE FIRM DELIVERY SERVICE

AVAILABILITY

This Rate applies in the entire territory served by the Company. It is available to any Customer who executes a Service Agreement with the Company for an on system Daily Firm Requirement (DFR), as agreed to by Customer and Company in said agreement, for not less than fifty (50) MCF of gas per day of firm service. Volumes delivered under this Rate shall be metered separately from service under any of the Company's other rates, except as provided for in Rates IS, NNS, and MBS. In lieu of separate metering, the Company may accept contractual commitments specifying minimum volumes of service under Rate LFD.

Service will be provided by the Company where the Customer provides suitable gas delivered to a Company authorized receipt point, as determined by the Company in its sole discretion, provided Company has available on-system and/or pipeline capacity available in such quantities to meet Customer requirements. The Company shall be under no obligation to maintain on-system facilities required for service beyond the term of an executed service agreement.

Unless otherwise agreed by the Customer and Company, the Customer must enter into a Service Agreement for a minimum term of two (2) years. The Service Agreement shall continue in force for consecutive two (2) year periods unless cancelled by Customer upon one (1) year written notice to the Company prior to the expiration of the then current Service Agreement term. The Customer shall remain liable for minimum bill requirements for the length of the Service Agreement under this Rate, including applicable penalties, in the event the Customer defaults on its Service Agreement before the end of its term.

Delivery Service shall be provided for all volumes provided by the Customer for which the Company has available delivery capacity, subject to the curtailment provisions of the Company's Tariff, applicable rules and regulations of the PUC and any other governmental mandates. **(C)**

Gas service in excess of volumes delivered by the Customer shall only be provided in accordance with applicable balancing provisions or in accordance with optionally elected and approved balancing or standby services.

The DFR shall be the Company's contracted maximum firm delivery obligation to the Customer on any day and shall be no less than fifty (50) MCF. Service in excess of the DFR is interruptible in accordance with the terms of Rate IS.

Service under Rate LFD is subject to the terms set forth under Section 22 - General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

(C) Indicates Change

RATE LFD - Continued

LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Demand Charge, the Distribution Charge and any Excess Take Charge as described below. The following are maximum rates.

Customer Charge: $670.00

Plus
Maximum Demand Charge: $5.0706/Mcf of Customer's elected DFR.

Plus
Maximum Distribution Charge: $1.1380/Mcf (all volumes) **(C)**

Plus
SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C – Extended TCJA Temporary Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I - Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

RETAINAGE RATE

Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, AND IS, paragraph 22.1(j).

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

EXCESS TAKE CHARGE

Except as provided in the Company's *Nomination Procedure*, for authorized usage on any day in excess of the Daily Firm Requirement there will be a charge of $6.00 per MCF in addition to the charges specified in the rate table.

(C) Indicates Change

RATE LFD - Continued

LARGE FIRM DELIVERY SERVICE

MINIMUM BILL

Monthly: The Minimum Monthly Bill shall be the Customer Charge, Demand Charge and Charge for Other Transportation.

Annual: The Minimum Annual Bill shall be based on the Customer maintaining a 0.50 annual load factor and shall be due and payable with the bill for the 12th month in the contract year. The Customer's actual load factor shall be determined by dividing the total volume of gas taken during the contract year (including volumes taken under the Retail and Standby Rider, the Cash-Out provisions of Section 22.2) by the sum of the Daily Firm Requirements for the contract year. If the actual load factor is less than 0.50, then, in addition to payment for actual usage, the Customer shall pay a Minimum Annual Bill charge equal to the product of: (1) the difference between 0.50 and the actual load factor, (2) the sum of the Customer's Daily Firm Requirements for the contract year, and (3) the average delivery charge paid by the Customer over the previous 12-month period, as calculated by the Company. If the Customer's actual load factor is greater than or equal to 0.50, no Minimum Annual Bill charge will be required.

CHARGE FOR OTHER TRANSPORTATION

If the Customer chooses to use the Company as agent in regard to transportation service by others, any costs calculated by or billed to the Company, with regard to such agency, shall be billed to the customer by the Company and may include an applicable administrative fee as agreed by the Customer and Company.

CHARGE FOR UNAUTHORIZED OVERRUN

Whenever it is necessary to restrict gas supplied under this Rate, the Company will provide due notice of such restriction. If a Customer, after having received due notice of restriction, shall take gas in excess of the amount made available by such notice, then the Customer shall be billed for such excess gas at the rate of Twenty-Seven Dollars and Fifty Cents ($27.50) per MCF, or the charge be calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater, plus the charge specified in the monthly rate table. Customer shall indemnify Company from any claims by third parties resulting from Customer's unauthorized overrun.

SERVICE UNDER OTHER RATES

Volumes purchased under the Retail and Standby Rider or under the Cash-Out provisions of Section 22.2 or taken under Rate NNS shall be included for the purposes of determining Excess Take Charge and Unauthorized Overrun gas.

RATE XD

EXTENDED LARGE FIRM DELIVERY SERVICE

AVAILABILITY

This Rate applies in the entire territory served by the Company on request of a Customer which the Company determines, in its sole discretion, has a prospective gas volume usage of at least 200,000 MCF per year at the time of execution or renewal of a Service Agreement.

Service will be provided by the Company where the Customer provides suitable gas delivered to a Company authorized receipt point, as determined by the Company in its sole discretion, provided Company has available on-system and/or pipeline capacity available in such quantities to meet Customer's requirements. The Company shall be under no obligation to maintain facilities required for service beyond the term of an executed Service Agreement.

Unless otherwise agreed to by the Customer and the Company, the Customer must enter into a service agreement for a minimum term of three (3) years. For a Customer requesting firm service, the Service Agreement shall specify an initial Daily Firm Requirement (DFR). The Customer shall remain liable for minimum bill requirements for the length of the Service Agreement under this Rate, including applicable penalties, in the event the Customer defaults on its Service Agreement before the end of its term.

For Customers requesting firm service, Delivery Service shall be provided for all volumes provided by the Customer for which the Company has available delivery up to DFR, subject to the Section 21 – Gas Emergency Planning provisions of the Company's tariff, applicable rules and regulations of the PUC and any other governmental mandates.

Service in excess of volumes delivered by the Customer shall only be provided in accordance with applicable balancing provisions or in accordance with optionally elected and approved balancing or standby services.

The DFR shall be the Company's contracted maximum firm delivery obligation to the Customer on any day. Service in excess of the DFR is interruptible and will be provided under terms and conditions identical to those set forth under Rate Schedule IS.

Service under Rate XD is subject to the terms set forth under Section 22 - General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

RATE XD -Continued

EXTENDED LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be negotiable and shall be the sum of the Customer Charge, Distribution Charge, Demand Charge if applicable, and the Minimum Annual Bill as described below.

The following are maximum rates.
Customer Charge: Charge as determined by negotiation.

Plus
Maximum Demand Charge: Charge as determined by negotiation.

Plus
Maximum Average Delivery Charge: $1.1380/Mcf **(C)**

Plus
SURCHARGES and RIDERS

Rider C – Extended TCJA Temporary Surcharge
Rider I – Distribution System Improvement Charge

RETAINAGE RATE

Unless otherwise agreed between the Customer and the Company, Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, paragraph 22.1(j)

MINIMUM BILL

Minimum Bill Volumes and terms shall be defined in the Service Agreement and determined by negotiation.

CHARGE FOR OTHER TRANSPORTATION

If the Customer chooses to use the Company as agent in regard to transportation service by others, any costs calculated by or billed to the Company, with regard to such agency, shall be billed to the Customer by the Company and may include an applicable administrative fee as agreed by the Customer and Company.

(C) Indicates Change

RATE XD - Continued

EXTENDED LARGE FIRM DELIVERY SERVICE

CHARGE FOR UNAUTHORIZED OVERRUN

Whenever it is necessary to restrict gas supplied under this Rate, the Company will provide due notice of such restrictions. If a Customer, after having received due notice of a restriction, shall take gas in excess of the amount made available by such notice, then the Customer shall be billed for such excess gas at the rate of Twenty-Seven Dollars and Fifty Cents ($27.50) per MCF, or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing, whichever is greater, plus the charge specified in the monthly rate table. Customer shall indemnify Company from any claims by third parties resulting from Customer's unauthorized overrun.

Volumes purchased under the Retail and Standby Rider or under the Cash-Out provisions of Section 22.2 or taken under Rate NNS shall be included for the purpose of determining Unauthorized Overrun gas.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

RATE R/S

RETAIL AND STANDBY RIDER

AVAILABILITY

Retail and Standby services are available under the Retail and Standby Rider to any Customer receiving service under Rate Schedules DS, LFD, XD and IS. Service shall be supplied only where the Company's facilities are suitable and available for the service desired. Service is subject to curtailment under Tariff Rule No. 21, Emergency Gas Planning.

Retail and Standby services under this schedule may be provided on a firm and/or interruptible basis. Subject to the Company's sole discretion, services shall be provided only if, and to the extent, sufficient Company and/or Customer provided capacity exists for the transportation of available gas supplies. Unless otherwise agreed by the Company and Customer, the Customer must enter into a service agreement for a minimum term of one (1) year with monthly payments for service taken.

The Company may provide capacity, supply or a bundled service, retail or standby, to the Customer under this rate schedule as per one or more of the following:
For Customers having upstream capacity rights: Company shall provide, or stand ready to provide, gas supplies to the Customer in such amounts and at such delivery or receipt points as necessary to meet Customers' contract requirements, as specified on a daily, monthly, seasonal or annual basis.

For Customers providing, selling or forwarding gas supplies to the Company for redelivery to Customer: Company shall provide, or stand ready to provide, pipeline and/or system capacity to deliver such gas supplies to the Customer.

For Customers requiring bundled sales service: Company shall provide, or stand ready to provide, the necessary pipeline and/or system capacity, and gas supplies necessary to provide gas service to the Customer at the Customers' metered location.

Where applicable, Customer must nominate standby service requirements by specifying a Nominated Standby Requirement (NSR) in MCF and a Daily Standby Requirement (DSR) in MCF per day of amounts equal to the Customer's total and daily standby supply requirements. Unless otherwise agreed by the Company and Customer, the firm or interruptible DSR shall be equal to the NSR divided by the number of days in the standby period.

Customers served under firm Rate Schedules DS, LFD, XD and IS may take firm retail and/or standby service under this rate schedule in any amount up to their available Daily Firm Requirement (DFR) or otherwise specified contract limit. All other terms and conditions of service as specified in Customer's Rate Schedules DS, LFD and XD and/or contract shall continue to apply.

Capacity and/or supply utilization under this rate schedule shall be on an as available basis for customers requesting retail and/or standby services. Subject to the Company's sole discretion, other incrementally obtained capacity and/or supply shall be assigned according to a Customer request queue or otherwise specified auction procedure. When necessary, such request queue or auction procedure shall be established in accordance with the terms outlined in the Company's *Nomination Procedure*.

The Company, upon notice to the Customer, may specify minimum levels of retail and/or standby nominations required for service under this rate schedule.

RATE R/S - Continued

RETAIL AND STANDBY RIDER

Service under Rate R/S is subject to the terms set forth in Section 22.2.

MONTHLY RATE TABLE

The charge for each Billing Month shall be the sum of the Customer Charge

Plus
The Capacity/Reservation Charge corresponding to the Customer's service election,

Plus
The Commodity Charge as shown below,

Plus
Administrative Service Fee: $75 per month.

Capacity/Reservation Charge:

Firm Retail Option: The applicable market price for available upstream capacity, plus the applicable charge for available system capacity, less any capacity charges paid under the Customer's applicable Rate Schedule, but in no case less than zero.

Firm Standby Option: The applicable Firm Standby Reservation Charge per MCF of DSR and/or per MCF of NSR.

a) The Firm Standby Reservation Charge shall be equal to the sum of the monthly contract demand rates charge by the Company's interstate pipeline suppliers divided by the sum of the daily contract demands.
b) The Firm Standby Reservation Charge shall be subject to increase or decrease whenever any of the Company's interstate pipeline suppliers make changes in their contract demand rates. Any change in the Standby Rate shall become effective on the first day of the month following the date on which the change in pipeline contract demand rate becomes effective.
c) The Firm Standby Reservation Charge revenues will be credited to the PGC.

Interruptible Standby Option: The applicable interruptible standby reservation charge per MCF of DSR and/or per MCF of NSR.

Plus

Commodity Charge: The distribution charge applicable under the Customer's Rate Schedule plus the applicable commodity cost, which shall be the identifiable additional cost of supply necessary to serve the Customer's usage, plus any applicable reservation cost of supply.

RATE R/S - Continued

RETAIL AND STANDBY RIDER

The minimum monthly bill under this rate schedule shall be the sum of the Customer and Capacity/Reservation Charges plus any commodity reservation costs per MCF of NSR.

SURCHARGES

Rider C – Extended TCJA Temporary Surcharge
Rider I – Distribution System Improvement Charge

Any charges or penalties imposed by pipeline suppliers as a result of usage under this rider shall, at the Company's sole discretion, be allocated to Customers according to each Customer's contractual obligation or be assigned to the Customer responsible for the incurrence of the charges or penalties.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

RATE IS

INTERRUPTIBLE SERVICE

AVAILABILITY

This Rate applies in the entire territory served by the Company. It is available to any commercial or industrial Customer using gas for any purpose when Customer has executed a Service Agreement with a term of at least one (1) year for use of gas under the terms of this Tariff.

Service under this Rate shall only be provided when, in the Company's sole discretion, sufficient system capacity is available.

Unless otherwise agreed by both Customer and Company, service under Rate IS is available only to Customer loads with documented installed capability to consume an alternate fuel, and the Customer must enter into a Service Agreement for a minimum term of one (1) year with monthly payments for service taken. The Customer shall remain liable for minimum bill requirements for the length of the Service Agreement under this Rate, including applicable penalties, in the event the Customer defaults on its Service Agreement before the end of its term.

The Customer and Company agree that a Manual Interruptible (MI) Customer must demonstrate that they have the capability of consuming at least 5,000 MCF of gas during April through October ("Off Peak Period"). For all Automatic Temperature Control ("ATC") Customers, the Customer shall install and operate equipment to transfer the fuel source of its interruptible equipment from natural gas to an alternate fuel at a predetermined temperature setting as determined annually by the Company.

The Company shall verify, prior to commencement of service for new Customers that the customer load being served qualifies under these provisions. The Company shall be permitted to inspect the facilities and piping at the premises of the Customer from time to time to confirm that the load being served so qualifies. The Company, at its discretion, may require such separate metering and piping and elimination of any cross-connection to non-qualifying end use equipment as may be necessary to enforce these provisions and to ensure the interruption of service hereunder during periods of restricted service. It is the Customer's responsibility to ensure qualifying alternate fuel capability is maintained in good working order as Company shall maintain no obligation for service during periods of interruption. If the Customer fails to meet any of the applicable conditions listed below, as determined by the Company in its sole discretion, the Company may discontinue service or transfer the Customer to the otherwise applicable firm or standby rate schedule, provided sufficient on-system capacity is available:

1) ability to maintain qualified alternate fuel facilities
2) 24-hour notification capability
3) maintain operable ATC equipment

Service will be provided by the Company where the Customer provides suitable gas delivered to a Company authorized contract receipt point, as determined by the Company in its sole discretion and only when in the opinion of the Company there are sufficient facilities and gas supply. The Company maintains sole discretion to determine the appropriate allocation of gas to Customers.

RATE IS - Continued

INTERRUPTIBLE SERVICE

Gas service in excess of volumes delivered by the Customer shall be provided only in accordance with applicable balancing provisions or in accordance with optionally elected and approved balancing or standby services.

INTERRUPTION NOTIFICATION

MI Customers agree to maintain a twenty-four hour capability to receive notification of interruptions by the Company. When notified by the Company, the MI customer must discontinue use of natural gas for the Rate IS account until notification of Company to resume use of natural gas under Rate IS. Except in an emergency circumstance, the Company will provide reasonable notice of any interruption at least two hours prior, or upon written request of the Customer, if agreed by Company, of up to six hours.

ATC Customers agree to maintain equipment required to automatically switch fuels from natural gas to Customer's alternate fuel and from alternate fuel back to natural gas based on outside temperatures, as determined solely by the Company and noticed annually to the Customer. The ATC equipment shall meet specifications as provided by the Company and shall be in working order at all times from November through March of each year.

The Company reserves the right to periodically verify MI and ATC Customer's alternate fuel as well as to verify the proper operation of ATC equipment.

MONTHLY RATE TABLE

Customer Charge: Charge as negotiated between the Customer and the Company.

Plus,

Distribution Charge:
Charge as negotiated between the Customer and Company based upon the alternate fuels that the Customer has the economic capability of consuming, inclusive of related business factors.

MINIMUM ANNUAL BILL

For ATC Customers: Shall be as negotiated by the Customer and Company but shall be no less than the product of five hundred (500) MCF times the distribution rate in effect on the first day of the Service Agreement or subsequent anniversary date if renewed Service Agreement.

For MI Customers: Shall be as negotiated by the Customer and Company but shall be no less than five thousand (5,000) MCF of natural gas in Off Peak Period times the distribution rate in effect on the first day of the Service Agreement or subsequent anniversary date if renewed Service Agreement.

RATE IS - Continued

INTERRUPTIBLE SERVICE

Unless the Company otherwise agrees, the Minimum Annual Bill shall be calculated at the end of any Service Agreement period, anniversary, or termination of service in accordance with terms of the Service Agreement. Volumes of natural gas taken under Standby Service during the Service Agreement period shall be credited to the Minimum Annual Bill volumes.

SURCHARGES and RIDERS

Rider C – Extended TCJA Temporary Surcharge
Rider I – Distribution System Improvement Charge

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

CHARGE FOR UNAUTHORIZED OVERRUN

Whenever it is necessary to restrict gas supplied under this Rate, the Company will provide due notice of such restriction. If a Customer, after having received due notice of restriction, shall take gas in excess of the amount made available by such notice, then Customer shall be billed for such excess gas at the rate of Fifty Dollars ($50.00) per MCF, or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater, plus the charge specified in the monthly rate table. Customer shall indemnify Company from any claims by third parties resulting from Customer's unauthorized overrun.

Gas delivered under the Rate IS or purchased under the Cash-Out provisions of Section 22.2 or the Retail and Standby Rider or taken under Rate NNS shall be included in the determination of Unauthorized Overrun gas.

RETAINAGE RATE

Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, AND IS, paragraph 22.1(j).

UGI GAS EXHIBIT F – CURRENT TARIFF

GAS CHOICE SUPPLIER TARIFF - PA P.U.C. NO. 7S

UGI UTILITIES, INC. - GAS DIVISION

GAS CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Aggregation Service

Issued: November 30, 2021

Effective for service rendered on and after December 1, 2021 in accordance with the Commission Order at Docket No. R-2021-3025652 entered October 7, 2021.

Issued By:

Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This supplement makes decreases and changes to existing rates(see page 2).

RULES AND REGULATIONS

1. THE CHOICE SUPPLIER TARIFF

1.1 Filing and Inspection. A copy of this Choice Supplier Tariff (Sections 1 – 11) (hereinafter "Supplier Tariff"), which includes the Charges and Rules and Regulations under which the Company will supply Aggregation Service to Company approved Natural Gas Suppliers (Choice Suppliers) serving customers under Rate Schedules RT and NT, is on file with the Pennsylvania Public Utility Commission and is available on the Company's website https://www.ugi.com/tariffs. **(C)**

1.2 Application. The provisions of the Supplier Tariff apply to all Choice Suppliers serving customers under Rate Schedules RT and NT.

1.3 Statement by Agents. No representative has authority to modify a Supplier Tariff rule or provision, or to bind the Company by any contrary promise or representation.

1.4 Rules and Regulations. The Rules and Regulations, as part of this Supplier Tariff, are a part of every Aggregation Agreement entered into by the Company pursuant to this Supplier.

1.5 Purpose of Tariff. This Supplier Tariff sets forth the basic requirements for interactions and coordination between the Company in its role as a Natural Gas Distribution Company (NGDC) and Choice Suppliers, and includes rules necessary for maintaining the delivery of gas to customers served under Rate Schedules RT and NT.

(C) Indicates Change

RULES AND REGULATIONS

2. CHOICE SUPPLIER QUALIFICATION

2.1 Service under this Tariff is contingent upon the Choice Supplier completing the Company's Choice Supplier Application Form to Serve Choice Customers (Application) and Company's approval of such Application. Choice Supplier shall include with its returned Application, payment of a non-refundable Enrollment Fee of five hundred dollars ($500). In the event the Choice Supplier submits an incomplete application, the Company shall provide written notice to the Choice Supplier of the Application's deficiencies. An incomplete Application will not be processed by the Company until it is fully completed by the Choice Supplier and received by the Company. Failure to submit a fully completed Application within thirty (30) calendar days following notice that the Application was incomplete will result in a rejection of the Application.

2.2 Choice Supplier must meet all pipeline credit standards and prove it is qualified by the pipeline to receive an assignment, release or transfer of pipeline capacity.

2.3 Processing of Application. The Company shall promptly process each Application and notify the Choice Supplier of the results of Company's review of such Application. If the Company rejects an application, the Company will provide a reason.

2.4 Approval of Application. Upon approval of Choice Supplier's Application, Company shall execute the duplicate originals of the Aggregation Agreement tendered by the Choice Supplier and return one copy to the Choice Supplier.

2.5 Supplemental Evaluations. Company may require additional periodic credit evaluations to ensure ongoing financial fitness as set forth in Section 8 of this Tariff. The Choice Supplier will be assessed a $250 fee for all credit evaluations performed by Company. The evaluation will be based on standard credit factors such as previous Choice Supplier's customer service record, Dun & Bradstreet or similar financial and credit ratings, trade references, bank information, unused line of credit, and financial information. Company shall have sole discretion to determine creditworthiness based on the above criteria but will not deny creditworthiness without reasonable cause.

2.6 A qualified Choice Supplier may opt to participate in the Purchase of Receivables ("POR") program offered by the Company by entering into a Purchase of Receivables Agreement. Upon approval of a Purchase of Receivables Agreement, the Company shall execute the duplicate originals of the Purchase of Receivables Agreement tendered by the Choice Supplier and return one copy to the Choice Supplier. A copy of the POR Agreement may be found on the Company's Energy Management website.

RULES AND REGULATIONS

3. CUSTOMER LIST

3.1 Customer Choice List. Company will maintain a list of Rate R, RT, N, and NT customers that have authorized the release of their information in a secure portion of a Web Site accessible to Choice suppliers in compliance with the requirements of Rule 3.2. When authorized by the customer, this list shall also include account number, address, rate code and / or historical usage.

3.2 Customer List Confidentiality. Such list shall only be accessible by Choice Suppliers that have executed a Confidentiality Agreement and are otherwise qualified to serve Rate RT and NT customers under this Tariff.

RULES AND REGULATIONS

4. CHOICE SUPPLIER OBLIGATIONS

4.1 Unless otherwise authorized by Company, Choice Suppliers must comply with the provisions of Section 7 of the Choice Supplier Tariff.

4.2 A Choice Supplier must provide and maintain a bond or other financial guarantee in a form and amount as set forth in Section 8 that is acceptable to Company and/or other PUC-approved Supplier of Last Resort.

4.3 A Choice Supplier must acquire or agree to acquire an adequate supply of natural gas to serve Choice Supplier’s Aggregation Pool and make or cause to be made arrangements by which such gas supplies can be transported to Company’s city gates, as directed by Company. Such supplies must be ranked on the transporting pipeline at the pipeline’s highest Predetermined Allocation ranking.

4.4 A Choice Supplier must enter into an Aggregation Agreement to serve Choice customers under Rate Schedules RT and NT.

4.5 A Choice Supplier must comply with Company system reliability requirements, including Daily Flow Directives (DFDs), Operational Flow Orders (OFOs), and notice requirements.

4.6 A Choice Supplier must comply with applicable communications standards, including approved internet based Electronic Data Interchange (EDI) procedures.

4.7 A Choice Supplier must cooperate with Company in the preparation of an annual reliability plan presented to the PUC.

4.8 A Choice Supplier must acquire and maintain a PUC license.

4.9 A Choice Supplier (including their nominating agents, if applicable) who nominates gas for delivery to the Company’s system must have and maintain Internet access. The Choice Supplier shall also provide Company with a valid email address and 24-hour contact information.

4.10 The Company’s provision of Aggregation Service is contingent upon the Choice Supplier paying all amounts billed to it by the Company in a timely manner.

4.11 Failure to comply with all Choice Supplier Obligations will result in the Company disqualifying the Choice Supplier from serving customers under Rate Schedules RT and NT. In the event the Company disqualifies a Choice Supplier, the Choice Supplier may appeal the disqualification to the PUC. If the PUC does not reverse the disqualification within 45 days, the Choice Supplier will be disqualified at the end of the 45-day period and its customers will be returned to sales service or switched to another Choice Supplier. Any Company disqualification will be on a non-discriminatory basis.

RULES AND REGULATIONS

4. CHOICE SUPPLIER OBLIGATIONS

4.12 If a Choice Supplier elects to participate in the Company's POR Program, the Choice Supplier must enter into a POR Agreement for the rate classes that it serves that will be included in the POR. The elected Rate Classes shall be one of the following: (1) RT only, (2) NT only, or (3) RT and NT. All receivables associated with basic natural gas supply services in the specific rate class, subject to the rate class elections made above, must be sold by the participating Supplier to the Utility. For the purposes of this provision, the phrase "basic natural gas supply services" shall include charges directly related to the physical delivery of natural gas to a retail customer but shall not include charges for "carbon-neutral" products, appliance maintenance service, energy efficiency services, termination or cancellation fees, security deposits or other products or services not directly related to the physical delivery of natural gas to a retail customers. Customer accounts that are billed for non-basic natural gas supply services will not be eligible for UGI's POR program. All of the NGS' customer accounts within the elected Rate Classes (subject to the volumetric limits contained in section 5.4) must be POR eligible accounts, with the exception of customers that purchase carbon-neutral products. NGSs may choose to use UGI consolidated billing for Non-POR eligible customers who are purchasing bundled "carbon-neutral" product offerings. The termination and reconnection provisions of Chapters 14 and 56 of the Public Utility Code and PUC regulations shall not be applicable to unpaid NGS charges for non-POR eligible accounts on consolidated billing. NGSs will be responsible for collecting unpaid NGS charges on non-POR eligible accounts on consolidated billing. UGI shall support rate-ready billing, and all NGS rates must conform to supported rate designs. For Purchased Customer Accounts, Company shall pay Choice Supplier an amount equal to 97.69% for residential amounts billed **(C)**
(inclusive of associated sales taxes) and 99.58% of non-residential amounts **(C)**
billed (also inclusive of taxes). Customer participation for NT shall be subject to Volumetric Eligibility pursuant to Section 5.4.

4.13 All existing customers of Choice Suppliers who elect to participate in the Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier and Company that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

All new customers enrolling with Choice Suppliers who are participating in Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier prior to enrollment, and by Company upon enrollment, that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

(C) Indicates Change

RULES AND REGULATIONS

5. OPERATIONAL REQUIREMENTS

5.1 Daily Delivery Requirements. The Company will communicate to each Choice Supplier a Daily Delivery Requirement (DDR). The DDR will be the required amount of gas to be delivered for the indicated date for each Choice Supplier's pool of customers served under Rate Schedules RT and NT and may specify the required points of delivery. The DDR includes a volume of gas that the Company will retain for Company use gas, and lost and unaccounted for gas, equal to 1.0% of total volume of gas delivered into its system for the Customer's account. Choice Suppliers who fail to deliver their DDR will be subject to penalties and imbalance charges as outlined in Rate AG. **(D)**

5.2 Daily Flow Directive. An order issued by the Company to address system management issues including actions necessary to comply with statutory directives and obligations. DFDs will be communicated to affected Customers or NGSs via e-mail if the Customer or NGSs prefer to receive notice in this manner and provide a valid e-mail address, or if no such preference is expressed, either electronically, by telephone, through the use of the media or by an alternate mutually agreed upon method between the Company and the Customer or NGS. DFD notices shall include an explanation of the cause of the DFD. Customers and NGSs must provide the Company with a 24-hour contact for DFDs. Failure to comply with a DFD may result in the Customer or NGS being assessed the penalty charge set forth in Section 22.4 of the Company's Gas Service Tariff.

5.3 Operational Flow Orders. A directive issued by the Company that is reasonably necessary to alleviate conditions that threaten the operational integrity of the Company's system, including actions necessary to comply with statutory directives and obligations OFOs will be communicated as soon as reasonably practical to affected Customers or NGSs via e-mail if the Customer or NGSs prefer to receive notice in this manner and provide a valid e-mail address, or if no such preference is expressed, either electronically, by telephone, through the use of the media or by an alternate mutually agreed upon method between the Company and the Customer or NGS. OFO notices shall include an explanation of the cause of the DFD. Customers and NGSs must provide the Company with a 24-hour contact for OFOs. Failure to comply with an OFO may result in the Customer or NGS being assessed the penalty charge set forth in Section 22.4 of the Company's Gas Service Tariff.

5.4 POR Volumetric Eligibility Requirements for Rate NT. All Rate NT Customers with annual usage of 1,000 Mcf or less will be eligible for inclusion into a POR program.

(D) Indicates Decrease

RULES AND REGULATIONS

6. BILLING AND PAYMENT

6.1 Billing Period. On or before the 15th of a month, Company shall send each Choice Supplier an invoice reflecting all charges incurred by the Choice Supplier for the prior calendar month activities. Such invoice may include charges related to adjustments for prior periods.

6.2 Payment. Payments will be due 10 days following issuance of the invoice. Choice Supplier shall make payment to the Company of such invoiced amount by wire transfer to the bank and account specified on the invoice. If the invoiced amount is less than $1,000, payment can be made by check, payable to the Company. Unpaid balances shall accrue interest at the rate of 1.5 percent per month. Unpaid balances may result in the Company accessing the financial security posted by the Choice Supplier and / or the Choice Supplier being disqualified from providing Aggregation Service.

6.3 Billing Dispute. If Choice Supplier asserts a good faith billing dispute, the Choice Supplier shall inform the Company in writing of such dispute and pay the undisputed amount. The disputed amount shall accrue interest at the effective prime rate of interest as published under "Money Rates" by "The Wall Street Journal", or the maximum contract rate permitted by law, whichever is less. The Choice Supplier and the Company shall endeavor to resolve any disputes promptly and the amount determined to be properly invoiced, plus accrued interest on such amount shall be paid to the Company within fifteen (15) days following such resolution. Unpaid amounts not subject to dispute shall accrue interest at the rate specified in 6.2.

6.4 Licensed Supplier Budget Billing. The Company will bill all budget billing amounts calculated and provided by the Licensed Supplier. The Company will not determine a Licensed Supplier's budget bill charge unless the account is being billed under the POR program.

RULES AND REGULATIONS

7. NOMINATION PROCEDURE

7.1 Customer Choice Nomination Procedure. The Nomination Procedure specifies requirements for nominating, scheduling, balancing, and communicating information relating to Choice Supplier's gas deliveries for customers served under Rates RT and NT.

7.2 Contact Persons. A list of Company contact persons will be posted on the Company's Web Site, located at https://ugi.outsystemsenterprise.com/UGIContacts_FO/, or its successor, along with their department affiliation, email address, and telephone number.

7.3 Mandatory Assignment. As used in this tariff the term "Firm Commodity Supply Alternative" shall mean a Company purchase of natural gas, delivered directly to its distribution system or at points along Company pipeline capacity routes (Commodity Delivery Points), constituting a component of Company's PGC supply portfolio and an alternative to pipeline capacity contracts upstream of the Commodity Delivery Points or other firm sources of PGC supply. Firm Commodity Supply Alternative contractual arrangements may require the payment of demand charges or minimum take requirements. Except as provided below, Choice supplier shall be required to accept releases of Company pipeline capacity combined with bundled city gate sales and, as applicable, peaking sales of gas from Company and sales of gas associated with Firm Commodity Supply Alternative arrangements, in accordance with the following assignments:

A monthly release of interstate pipeline capacity or allocation of Firm Commodity Supply Alternative in an amount equal to forty-three percent (43%) of the Peak **(C)** Day Delivery Requirement ("PDDR") of the Choice Customers served by the Choice Supplier during the month shall be released or allocated at a price equal to the projected weighted average demand cost of all PGC capacity, storage, peaking and Firm Commodity Supply Alternative assets, divided by .283. Effective November 1, **(C)** 2020, to the extent the full Firm Commodity Supply Alternative is not fully nominated by Choice Supplier to satisfy its DDR, the remaining daily quantity may be nominated to a non-Choice transportation customer or pool of non-Choice transportation customers.

The Company shall also provide Choice Suppliers with a must-take Monthly Bundled Sale Quantity ("MBSQ") during each winter month of November through March, and the Choice Supplier would be permitted to nominate and purchase gas at the Company's city gates throughout each winter month, subject to the Maximum Daily Quantity ("MDQ") limits, up to the MBSQ. The MDQ equals twenty-one percent(21%) **(C)** of the PDDR of the Choice Customers served by the Choice Supplier during the month multiplied by the percentage shown on the Company's Energy Management website under the heading Maximum Daily Bundled Sale Percentages. The minimum daily quantity is zero. Choice Suppliers are required to nominate to the Company a daily quantity for bundled sales no later than 2:00 P.M. Eastern Prevailing Time on each Intercontinental Exchange ("ICE") trading day for deliveries applicable to the ICE flow dates. If no nomination is received, the nomination quantity would default to zero. The Company reserves the right to issue Operational Flow Orders ("OFO") that can modify the daily bundled sale MDQ or require certain levels of deliveries from the released firm transportation contracts. These OFOs would be issued for operational reasons only. MBSQs would be based on the Company's storage withdrawal plan, to be updated annually, and communicated as a percentage of each Choice Supplier's pre-month normalized

(C) Indicates Change

RULES AND REGULATIONS

7. NOMINATION PROCEDURE - CONTINUED

delivery requirements, which will be shown on the Company's Energy Management website under the heading Must-Take Monthly Bundled Sale Percentages.

If the full MBSQ is not nominated and purchased by the end of each such winter month, the shortfall ("Bundled Sale Cash-In quantity") would be purchased by the PGC ("Bundled Sale Cash-In amount") as follows:

a. The DDR Variation Percentage is the sum of the actual DDRs experienced by a Choice Supplier divided by the sum of the pre-month average DDRs that was used to calculate the MBSQ, converted to a percentage. For any month where the DDR Variation Percentage is greater than ninety percent (90%), the Bundled Sale Cash-In amount would equal (1) the product of (a) 0.90 times the lowest absolute low for the Texas Eastern, M-2 receipts index price as published in Platts' Gas Daily for the applicable month of flow minus (b) the summer index price used for bundled sales (the "Bundled Sale Cash-In index") times (2) the Bundled Sale Cash-In quantity. If the resulting amount is positive, it would be credited to the Choice Supplier, or if negative, would be billed to the Choice Supplier.

b. In recognition of the effects of extreme warm weather conditions, shortfall amounts would be purchased as follows under such conditions:

   i. For any month where (a) the DDR Variation Percentage is less than or equal to ninety percent(90%) and (b) the Bundled Sale Cash-In quantity is less than or equal to the MBSQ minus the product of the DDR Variation Percentage times the MBSQ, then the Bundled Sale Cash-In amount would equal (1) the First of the Month Price called "Columbia Gas Transmission Corp., Appalachia" as published in Platts' Gas Daily Price Guide ("Inside FERC") for the month subsequent to the applicable month in which the Bundled Sale Cash-In quantity was created minus the summer index price used for bundled sales (the "Alternate Bundled Sale Cash-In Index") times (2) the Bundled Sale Cash-In quantity. If the resulting amount is positive, it would be credited to the Choice Supplier, or if negative, would be billed to the Choice Supplier.

   ii. For any month where (a) the DDR Variation Percentage is less than or equal to ninety percent (90%) and (b) the Bundled Sale Cash-In quantity is greater than the MBSQ minus the product of the DDR Variation Percentage times the MBSQ, then the Bundled Sale Cash-In amount would equal (1) the Alternate Bundled Sale Cash-In Index, as defined in Section 7.3.b.i, times the DDR Variation Percentage times the MBSQ plus(2) the Bundled Sale Cash-In Index, as defined in Section 7.3.a,times the difference of the Bundled Sale Cash-In quantity minus the product of the DDR Variation Percentage times the MBSQ. If the resulting amount is positive, it would be credited to the Choice Supplier, or if negative, would be billed to the Choice Supplier.

RULES AND REGULATIONS

7. NOMINATION PROCEDURE - CONTINUED

In addition to the bundled sales described above, Choice Suppliers shall be required to purchase from Company a separate bundled sale on peak days ("Peaking Sale") equal to an amount up to thirty-six percent (36%) of the PDDR of the Choice **(C)** Customers served by the Choice Supplier during the month. The Peaking Sale would be made on winter days when the Choice Supplier's DDR exceeds the sum of the released firm capacity and the MDQ associated with the bundled sale. The Peaking Sale quantity would be the difference of the Choice Supplier's DDR minus the sum of the released firm capacity and the MDQ associated with the bundled sale. The Peaking Sale price would be based on the commodity cost of the Company's peaking services. If weather conditions cause the Choice Supplier's DDR to exceed the Choice Supplier's PDDR, the Choice Supplier would be responsible for arranging for supplies to meet the additional delivery requirements for its Choice Customers.

Also in addition to the bundled sales described above, to the extent Company's design cold PGC supply portfolio includes Firm Commodity Supply Alternative contractual arrangements containing minimum take requirements, Choice Supplier shall also be required to make monthly purchases of natural gas from Company in an amount and at the commodity price Company would have been required to pay under the Firm Commodity Supply Alternative contractual arrangements had the Choice Customers projected to be served by the Choice Supplier during the month received PGC service. To the extent Company's design cold PGC supply portfolio includes Firm Commodity Supply Alternative contractual arrangements not containing minimum take requirements, Choice Supplier may elect on a month-to-month basis to make monthly bundled city gate purchases of natural gas from Company in an amount and at the commodity price Company would have been required to pay had the Choice Customers projected to be served by the Choice Supplier during the month received PGC service, provided, however, that nothing in this section shall preclude the Company from issuing OFOs requiring additional purchases of natural gas in accordance with the provisions of Section 5.3 of this tariff.

7.4 Capacity Recall. All capacity assigned, released or transferred by Company is subject to recall, or in the event:

a. A Choice Supplier is disqualified as an approved Choice Supplier on Company's system; or

b. The amount of capacity assigned, release or otherwise transferred is no longer required to serve the Choice Supplier's Pool; or

c. The Choice Supplier fails to comply with Section 4 of this tariff (Supplier Obligations) and the capacity is required by the Company or PUC approved Supplier of Last Resort to meet its firm commitments; or

d. The capacity is needed to protect the Company's gas distribution system integrity or meet the Company's public utility obligations.

(C) Indicates Change

RULES AND REGULATIONS

7. NOMINATION PROCEDURE - CONTINUED

7.5 Agents. A Choice Supplier may have one or more agents who perform one or more supply obligations under this Supplier Tariff. In the event such an agent or agents are utilized, Choice Supplier shall notify Company of the responsibilities of the Agent and shall provide Company with the Agent's valid e-mail address, 24-hour contact, and phone number for contact purpose. Choice Suppliers using Agents shall remain liable for all charges and penalties.

7.6 Determination of Capacity Assignment Quantities. Assignments, releases or transfers of upstream pipeline firm transportation capacity made pursuant to Section 7.3 shall be made on the basis of and in accordance with the supply portfolio held by Company at the time of assignment and the composition of the Choice Supplier's Pool. Each month the Company will evaluate and adjust the capacity releases quantity made to the Choice Supplier from time to time, as required.

7.7 City Gate Receipt Points. For nomination purposes, all transportation volumes received on behalf of customers served under Rates RT and NT shall be nominated to the Company's City Gate receipt points. Company reserves the right to specify delivery receipt points.

7.8 Daily Nominations. Choice Suppliers serving Rate RT and NT customers shall submit daily nominations equal to the DDR, consistent with the Company's requirements.

7.9 Third Party Supply Nominations - Customer Consent. All Company Choice Customers must provide consent to any Choice Supplier nominating on their behalf. Enrollments by Choice Suppliers are deemed to constitute that the customer has provided such consent. For transportation customers served under Rates RT and NT the Choice Supplier must maintain and produce upon request by Company evidence of customer consent within one business day notice.

RULES AND REGULATIONS

8. FINANCIAL SECURITY

8.1 Financial Security. A Choice Supplier shall provide financial security to ensure that Company and/or other PUC-approved Supplier of Last Resort is able to receive, without undue delay, funds or other forms of remuneration sufficient to meet the financial consequences of a Choice Supplier's failure to perform its natural gas supply delivery service obligations hereunder. Company may also use such forms of financial security to satisfy in part or in whole a Choice Supplier's obligation to pay the penalties authorized by this Supplier Tariff. The amount and the form of the security, if not mutually agreed upon by the Company and the Choice Supplier, shall be based on the criteria established under 52 Pa. Code § 62.111(c) and as set forth in this Section 8.

8.2 Amount of Financial Security. A Choice Supplier seeking to be licensed to provide service on the Company's system shall be required to provide 1) a minimum surety level of $50,000 or 2), if higher, the sum of the surety level requirements calculated on a customer basis equal to (i)$60.00 per customer for residential customers; and ii)$94.24/Dth times the Design Day Requirement (in Dth) for Choice Supplier's pool of non-residential customers. This security level shall be subject to adjustments as provided in Section 8.5. Provided, however, the Company reserves its right to file to change that methodology after the effective date of new rates established in the proceeding if the security levels prove inadequate.

8.3 Forms of Financial Security. For purposes of satisfying the amount of financial security determined under Section 8.2 hereof, the Choice Supplier shall provide financial security in one or more of the following manners, in a form reasonably acceptable to the Company and/or other PUC-approved Supplier of Last Resort, and shall reimburse Company for attorneys' fees and all related external costs incurred by Company in implementing and enforcing the form of financial security provided by Choice Supplier:

(a) cash;

(b) performance bond;

(c) irrevocable letter of credit;

(d) guarantee from a third party;

(e) call options satisfying the requirements of Section 8.4 hereof;

(f) in the case of Choice Suppliers with annual operating revenues of less than $1 million; real or personal property placed in escrow or other arrangement that would make the property readily available to Company in the event of the Choice Supplier's non-performance or entering into bankruptcy, provided that the Choice Supplier (i) provides a verified statement, certified by a third party report, showing that the Choice Supplier has clear title to the property and that the property has not been pledged as collateral, or otherwise encumbered in regard to any other legal or financial transaction; (ii) provides a current appraisal report of the market value of the property; and (iii) grant the Company, upon request, a security interest in such property in a form acceptable to Company;

(g) accounts receivable pledged or assigned to the Company pursuant to a Company PUC-approved POR program satisfying the requirements of Section 8.6 hereof; or

RULES AND REGULATIONS

8. FINANCIAL SECURITY – CONTINUED

(h) another form of financial security mutually acceptable to Company and Choice Supplier.

8.4 Call Option Requirements. A Choice Supplier may meet some or all of its financial security obligations determined under Section 8.2 hereof by providing to Company or paying the Company to procure a Call Option for a volume equal to the monthly Design Day Requirements of the Choice Supplier's customers served under Rate Schedules RT and NT. Unless otherwise authorized by Company, the Call Option must have a strike price equal to or less than the Choice Supplier's contract price(s) with its customers served under Rate Schedules RT and NT. The Call Option shall allow Choice Supplier or Company to call on a volume equal to the Choice Supplier's Design Day Requirement on each and every day the Call Option is in place such that the exercise on any day does not preclude or impact the ability to exercise the option on a subsequent day. Call Options shall be subject to the following requirements:

(a) If procured by Choice Supplier, the Call Option must enable Company to exercise the Call Option in the event of non-performance by the Choice Supplier without obtaining the prior consent of Choice Supplier;

(b) If procured by Choice Supplier, the Call Option may be exercised by it for any reason, including economic reasons, on any day when Company and/or other PUC-approved supplier of last resort does not need to exercise it because of Choice Supplier's failure to perform its natural gas supply delivery service obligations hereunder;

(c) Company shall specify the period over which the Call Option may be exercised;

(d) The Call Option may be a direct NYMEX instrument, or it may be obtained indirectly from a third party. If the Call Option is a direct NYMEX instrument, the Choice Supplier shall assign the applicable capacity to Company. If the Call Option is obtained indirectly from a third party, then the transaction point shall be at a Company-approved city gate receipt point; and

(e) Choice Supplier shall be responsible for the cost of the Call Option.

8.5 Adjustments to Financial Security Level. From time to time, the Company shall review the financial security provided by a Choice Supplier and determine whether any adjustments are required consistent with the formula under Section 8.2 hereof. The Company shall use the following factors to determine whether any such adjustments are required:

(a) A change in the Choice Supplier's recent operating history on Company's system or on other NGDS systems has materially affected Company system operation or reliability. A change that could materially affect the Company system or reliability may occur when the Choice Supplier fails to deliver natural gas supply sufficient to meet its customers' needs on 5 separate occasions within a 30-day period or fails to comply with Company Operational Flow Orders as defined at 52 Pa. Code § 69.11.

RULES AND REGULATIONS

8. FINANCIAL SECURITY - CONTINUED

(b) A significant change in the number of customers served, in the volume of gas delivered, or in the unit price of natural gas or a change in the class of customers being served by the Choice Supplier. A change over a consecutive 30-day period of 25% in the number of customers served, in the volume of gas delivered or in the average unit price of natural gas would represent a significant change.

(c) A change in the Choice Supplier's credit reports that materially affects the Choice Supplier's creditworthiness. A Choice Supplier's creditworthiness could be materially affected when two of the following credit rating companies change the Choice Supplier's credit rating: Dun & Bradstreet, Standard & Poor's Rating Services, Inc., TransUnion LLC, EQUIFAX Inc., Experian Information Solutions, Inc.

(d) A change in operational or financial circumstances that materially affects the Choice Suppliers' creditworthiness. A Choice Supplier's creditworthiness could be materially affected when two of the following investment rating companies change the Choice Supplier's rating of its issued securities from an investment grade or good rating to a speculative or moderate credit risk rating, and vice versa: Standard and Poor's Rating Services, Inc., Moody's Investment Services, Inc., Fitch, Inc., A.M. Best Company, Inc. and DBRS, Inc.

8.6 <u>POR Requirements</u>. A Choice Supplier may meet part or all of its financial security obligations determined under Section 8.2 hereof utilizing the accounts receivable pledged or assigned to the Company pursuant to a Company PUC-approved POR program, provided that Choice Supplier executes a Security Agreement which, among other things: (a) grants Company a first priority security interest in the accounts payable to Choice Supplier for the purchased receivables; and (b) grants Company an immediate right of set off against any account payable to Choice Supplier for any obligation owed by Choice Supplier to Company.

To reflect the variability in the amounts owed by Company to Choice Supplier for purchased receivables given seasonal variations in customer loads, the amount of this form of security will be determined pursuant to the following formula: (The average daily Mcf volume of gas delivered by the Choice Supplier during the lowest 30 day period of volume during the past 12 months for accounts enrolled in the POR program) times (the lowest rate per Mcf charged by the Choice Supplier during the past 12 months) times (the number of days between the purchase of and payment for a Choice Supplier's receivables).

8.7 <u>Notice</u>. If the Company determines, based on the criteria in Section 8.5 hereof, that an adjustment in the amount or type of security that a Choice Supplier must provide is warranted, the Company shall provide notice of its determination to the Choice Supplier in writing. The Choice Supplier shall comply with the Company's determination no later than 5 business days after the date the Choice Supplier was served with notice of the Company's determination. If the Choice Supplier disagrees with the Company's determination, the Choice Supplier may file a dispute with the Company, and the Company and the Choice Supplier must attempt to resolve the dispute within 30 days after the date that the Company was notified of the dispute.

RULES AND REGULATIONS

9. ENROLLMENT OF CUSTOMERS INTO RATE SCHEDULES RT AND NT

9.1 To be served under Rate Schedules RT and NT, a Customer must be enrolled by the Choice Supplier elected by the Customer. Such enrollment by the Choice Supplier must be provided in an electronic file to the Company via an approved internet-based EDI transaction. The requirement filed shall include:

a. The customer’s name;
b. The customer’s address;
c. The customer’s Company account number;
d. The specific transaction;
e. The elected billing option.

9.2 Company Confirmation. Company will electronically confirm receipt of the enrollment information and within one (1) business day and subsequently provide an electronic validation of the Choice Supplier’s transmitted information.

9.3 Determination of Gas Flow Date. For enrollments received on or before the 15^{th} of any calendar month, the customer will be switched to Rate Schedule RT and NT, where the customer does not respond within 5 days from the Company’s mailing of a letter confirming the election to be served by the Choice Supplier, on the Customer’s regularly scheduled meter reading date in the calendar month immediately following the month the enrollment information was received. For enrollments received after the 15^{th} of any calendar month, the customer will be switched to Rate Schedule RT and NT, where the customer does not respond within 5 days from the Company’s mailing of a letter confirming the election to be served by the Choice Supplier, on the Customer’s regularly scheduled meter reading date in the second calendar month following the month the enrollment information was received.

RULES AND REGULATIONS

10. RATE AG - AGGREGATION SERVICE

AVAILABILITY

Rate AG - Aggregation Service (AG Service) is available to and required for an approved Natural Gas Supplier (Choice Supplier) licensed by the PUC to provide natural gas supply service to customers who qualify to receive service under Rate RT (General Service - Residential Transportation) or Rate NT (General Service - Non-residential Transportation)(hereinafter a Choice Supplier).

AGGREGATION SERVICE

A Choice Supplier qualified to receive Rate AG Aggregation Service shall aggregate the load of customers served under Rates RT and NT customers in an Aggregation Pool. Such Aggregation Pool is limited to customers served under Rates RT and NT.

ASSIGNMENT OF COMPANY PIPELINE CAPACITY

Company has the right to require the Choice Supplier to accept a release, assignment or transfer of Company pipeline capacity on a recallable basis. The minimum such assignment shall be is one (1) Dth per day per pipeline path.

RATE TABLE

Balancing Fee for Choice Supplier ($/MCF) – As posted.

(Total Cost of Pipeline Assets Retained by Company for System Balancing - Balancing Related PGC Credits) divided by (Projected Annual Sales and Transportation Volumes Utilizing the Assets, as projected in each annual 1307(f) filing). This rate will be posted on Company's Delivery Service Web Site or its successor and will be updated as required.

Pipeline Capacity and Bundled Sales:
Choice Supplier shall be responsible for applicable charges pursuant to Section 7.

RULES AND REGULATIONS

10. RATE AG - AGGREGATION SERVICE - CONTINUED

PENALTIES

Failure to Deliver DDR:
The difference in price between the highest published index price for the Texas Eastern, M-3 and the lowest published index price for Texas Eastern, M-2 as published in *Platts' Gas Daily* on the table "Daily Price Survey" corresponding to the date the failure to deliver occurred, plus the applicable transportation charges from Texas Eastern M-2 to M-3, but shall not be lower than $0.25/per Dth, applied to the difference between the DDR and the delivered volumes, plus all incremental costs incurred by Company as a result of the failure to deliver the DDR.

The Company may not charge for delivering in excess or under of the DDR if the overdelivery or underdelivery is anticipated to benefit the distribution system's daily balancing position as determined by Company in its sole discretion.

Failure to Comply with an OFO or DFD: **(C)**
The Company has the right to issue Operational Flow Orders and Daily Flow Directives at any time. Failure to comply with any OFO or DFD shall result in a penalty charge of Fifty Dollars ($50) per Dth or the highest of the charges calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge for any delivery region, whichever is greater.

NOTICE

A Choice Supplier must provide Company, or any PUC-authorized alternative Supplier of Last Resort and its Rate RT and NT Customer(s) with ninety (90) days advance written notice of its intention to exit the market. In the event a Choice Supplier discontinues service or exits the market before its contract for natural gas supply service to a Rate RT and NT Customer expires and such Customer returns to its Supplier of Last Resort, Choice Supplier shall provide all contract billing data required by Company or other PUC-approved Supplier of Last Resort to render bills to Choice Supplier's customers for the period between Choice Supplier's default or exit from the market and the customer's next meter reading date.

BALANCING

Company will balance the daily difference, if any, between the anticipated Customer use, as communicated through the DDR, and the actual usage of Choice Supplier's customers. For this service, the Choice Supplier shall pay to Company the applicable Balancing Fees shown in this rate schedule, per MCF of Aggregation Pool usage, as measured at the meter.

(C) Indicates Change

RULES AND REGULATIONS

10. RATE AG - AGGREGATION SERVICE – CONTINUED

RECONCILIATION

Company shall calculate the difference between the actual deliveries of each Choice Supplier's Aggregation Pool, and the usage of each such Aggregation Pool. The Company shall adjust future DDRs to account for any usage differences between forecasted weather and actual weather. Where actual meter reads cannot be obtained, the Company will estimate usage and such estimate shall be deemed actual usage. At the time a Choice Supplier no longer has any Choice Customers enrolled, the cumulative difference between delivered volumes and usage of the Choice Supplier's Aggregation Pool shall be cashed out at Company's average cost of gas purchased for the most recent 12 months. The average cost of gas shall be calculated as the product of the total commodity cost of gas purchases including transportation and fuel used and accounted for the most recent 12 months, divided by tariff sales for the same 12-month period.

NATURAL GAS SUPPLY PLANS

Choice Supplier shall cooperate with Company in the preparation of such reliability plans required under Section 1317 of the Public Utility Code, and shall provide all reasonable information related to gas deliverability assets under its control required by Company including providing copies of pipeline capacity contracts or delivered supply contracts, or, in lieu of providing such contracts, warrant pertinent information as required by the Company or any regulatory authority. Choice Supplier shall also enter into any necessary contractual arrangements, or make any required regulatory filings, to ensure that contracts and assets under its control, which are relied upon in Company's reliability plan, are available to Company or PUC-authorized supplier of last resort in accordance with Choice Supplier's obligations under its Aggregation Agreement and this Tariff.

COMPLIANCE WITH THE PENNSYLVANIA PUBLIC UTILITY COMMISSION REQUIREMENTS

Choice Supplier shall at all times comply with all applicable PUC requirements and regulations.

UGI UTILITIES, INC.- GAS DIVISION

11. AGGREGATION AGREEMENT

FOR RATE SCHEDULES RT and NT

(Pro Forma)

This Aggregation Agreement for Rate Schedules RT and NT ("Aggregation Agreement") is made and entered into this _______ day of ______________, 20___, by and between UGI Utilities, Inc. – Gas Division, a Pennsylvania Corporation ("Company"), and __________________, a _________________________ ("Choice Supplier").

WHEREAS, Company is a Pennsylvania public utility that, amongst other things, provides intrastate transportation service to Rate RT and NT customers located within its certificated service territory; and

WHEREAS, Choice Supplier is engaged in the business of selling natural gas supply services, and desires to market such services to Rate RT and NT customers located within Company's certificated service territory; and

WHEREAS, pursuant to the terms and conditions set forth in this Aggregation Agreement, Company is willing to receive natural gas supplies at specified points of interconnection situated between Company's facilities and the facilities of one or more interstate natural gas pipeline companies to serve the aggregated load of Rate RT and NT customers served by Choice Supplier, and to provide other services to facilitate the provision by Choice Supplier of natural gas supply services to customers; and

WHEREAS, pursuant to the terms and conditions set forth in this Aggregation Agreement, Choice Supplier is willing to deliver natural gas supplies for receipt by Company for subsequent transportation and redelivery at specified end-use customer locations, and to acquire aggregation services from Company.

NOW, THEREFORE, intending to be legally bound hereby, Company and Choice Supplier agree as follows:

ARTICLE I. DEFINITIONS

For the purposes of this Aggregation Agreement, in addition to any definitions set forth in Company's Gas Service Tariff and *Nomination Procedure*, which are hereby incorporated herein by reference, the following definitions apply:

1. **Aggregation Service** means services provided by Company to Choice Supplier to facilitate the delivery of gas supplies to customers receiving service under Rates RT and NT.

2. **Balancing** means services provided by Company to cover differences between a Choice Supplier's Daily Delivery Requirement and the actual usage of the Choice Supplier's Aggregation Pool.

3. **Customer** means a recipient of service under Rate Schedules RT and NT that contracts for natural gas supply service from a Choice Supplier.

4. **Daily Delivery Requirement (DDR)** means the daily quantities of natural gas supplies a Choice Supplier is required to deliver for an Aggregation Pool, as forecasted and communicated by Company, and may specify the required points of delivery. Such forecast shall be calculated to include volumes needed for end-use requirements, prior imbalances and Company use and unaccounted for gas.

5. **Delivery Point** means a point specified by Company where Choice Supplier may deliver natural gas supplies for subsequent redelivery by Company to Choice Marketer's Rate RT and NT customers.

6. **Rate Ready Billing** is the method of billing used by the Company to calculate the natural gas supply services provided by the Choice Supplier. Under this method, the Company uses actual meter readings obtained by the Company, or estimated consumption when the Company is unable to obtain an actual meter reading, and billing rate information provided by the Choice Supplier to calculate the bill.

7. **Transportation** means a service provided by Company on its facilities that enables gas owned by others to be received into, moved through, and delivered out of facilities owned, leased, or operated and controlled by Company.

8. **Upstream Capacity Assignment, Release or Transfer** means the process to provide access to interstate pipeline capacity and storage contracts owned by Company to Choice Supplier pursuant to Company's tariff and any applicable regulatory rules.

ARTICLE II. TERM

This Aggregation Agreement shall become effective on _________________ and shall remain in effect, unless terminated pursuant to Section 6.1 hereof, or by either party by providing ninety (90) days' prior written notice, for so long as Choice Supplier is qualified to receive Rate AG service from Company. In the event this Aggregation Agreement expires or terminates, Company shall have no obligation, as between Choice Supplier and Company, to accept any natural gas supplies tendered by Choice Supplier for receipt into Company's facilities, and Choice Supplier's payment and financial obligations shall continue until fully discharged.

ARTICLE III. CHOICE SUPPLIER'S OBLIGATIONS

1. **Compliance**. Choice Supplier agrees that it shall comply with all of the applicable terms and conditions of Company's Gas Service Tariff and Company's Supplier Tariff, both of which are hereby incorporated by reference.

2. **Creditworthiness**. Choice Supplier shall establish, and maintain throughout the term of this Aggregation Agreement, and thereafter until all of Choice Supplier's payment obligations incurred under this Aggregation Agreement have been fully discharged, a satisfactory Financial Security status with Company. To enable the Company to determine credit status, Choice Supplier will provide to the Company the following: 1) relevant financial information to determine creditworthiness; 2) appropriate trade and banking references; and 3) written consent for Company to conduct a credit investigation. In addition, Choice Supplier shall comply with the Financial Security provisions of Company's Supplier Tariff, and may, based on Choice Supplier's credit standing with Company, be required to provide financial security in excess of the minimum amounts specified therein.

3. **Standards of Conduct**. Choice Supplier shall abide by all standards of conduct and other legal requirements applicable to Choice Supplier's line of business, including but not limited to the standard of conduct applicable to Choice Suppliers set forth in rules and regulations established by regulatory bodies having jurisdiction over Choice Supplier's activities, and other applicable law.

4. **Payments**. Choice Supplier will remit payment for all services within 10 days after receipt of Company invoice. A late payment charge of 1.50% per month will be applied to all outstanding balances as of the due date.

5. **Customer List**. Choice Supplier shall execute an Electronic Trading Partner Agreement and will keep confidential any customer information acquired either directly or indirectly from Company and use such information solely for the purpose of offering natural gas supply service to Rate RT and NT customers. In the event the Company determines the Choice Supplier impermissibly released customer information to another party, in addition to all available remedies, Company may, at its option, immediately cancel this Aggregation Agreement.

ARTICLE IV. COMPANY'S OBLIGATIONS

1. **DDR**. Company shall provide Choice Supplier with its DDR for each Gas Day. Company shall accept receipt of all gas volumes up to the DDR. Company shall have the right to accept, but shall in no instance be required to accept, an Over-delivery by Choice Supplier. The acceptance of such over delivery shall not constitute any waiver of any provisions of the Company’s Gas Service Tariff or *Nomination Procedure*.

2. **Monthly Statement**. Company shall bill Choice Supplier by the 15th of each month for services provided by Company during the preceding month and other amounts due to Company.

3. **Enrollment Notification.** Company shall generate and send a letter to all customers enrolled by a Choice Supplier indicating the supplier selected and the date service from the Choice Supplier is scheduled to commence. All customers enrolled by

the 15th of each month will be transferred to their respective Choice Supplier effective with their next calendar meter read if customer does not respond within five (5) days following confirmation to challenge the enrollment. Company shall send an electronic message confirming the selection to the Choice Supplier.

4. **Rate AG.** Company shall provide all of the other aggregation services applicable to Choice Supplier specified in the Rate AG provisions of its tariff.

ARTICLE V. BILLING SERVICE

5.1 **Standard Billing Service**. Company shall bill Choice Supplier's Rate RT and NT customers for natural gas supply services provided by Choice Supplier on a rate-ready basis unless (a) a Choice Supplier not participating in the Company's POR program elects to provide a separate bill for its charges or (b) a Choice Supplier's customer elects to receive a separate bill for such services from its Choice Supplier. Choice Supplier must provide all billing rate information no later than fifteen (15) days prior to the effective date of such rate. Company will input all requests for new plans within a reasonable time frame based on the number of requests received.

5.2 **Standard Billing Charges**. Choice Supplier shall pay to Company the following fees for billing services:

Billing Fee $0.25/Bill.

Billing Adjustment Fee

Affecting One (1) Month - $3.10/Revised Bill

Affecting More than One (1) Month - $3.60/Revised Bill

5.3 **Negotiated Billing Service**. In the event a Choice Supplier wants Company to provide a billing service other than the Standard Billing Service, such service shall be negotiated between Company and Choice Supplier.

5.4 **Choice Supplier Budget Billing.** The Company will bill all budget billing amounts calculated and provided by the Choice Supplier unless the account is being billed under the POR program, in which case the Company will provide budget billing to the customer. The Company will not determine or reconcile a Licensed Supplier's budget bill charge if the Licensed Supplier is not participating in the Company's POR program.

ARTICLE VI. REMEDIES

6.1. **Termination Upon Default**. In addition to other rights a party may have under this Aggregation Agreement, if either party fails to perform an obligation, or breaches any representation or warranty ("Defaulting Party") under this Agreement, then the other party (Non-Defaulting Party") shall have the right to terminate this Agreement by providing prior written notice thereof to the Defaulting Party. Termination pursuant to this Article shall be without waiver of any additional remedy, whether at law or in equity, to which the party not in default otherwise may be entitled for breach of this Agreement.

6.2. **Limitation of Liability**. Except as expressly permitted under this Agreement and Company's Gas Service Tariff, neither party shall be entitled to recover incidental, consequential or punitive damages, or lost profits, for any breach by the other party of an obligation, representation or warranty under this Agreement, provided such limitation shall not apply to willful or grossly negligent misconduct on the part of the Defaulting Party.

ARTICLE VII. REPRESENTATIONS, WARRANTIES AND INDEMNIFICATION

Choice Supplier warrants that 1) it shall have good title to all natural gas tendered for receipt by Company hereunder, or is authorized by the owner of such gas to tender it for delivery to Company, and 2) such gas will be free and clear of all liens, encumbrances, and claims whatsoever. Choice Supplier shall fully indemnify

Company, and save it harmless from all suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of a breach of such warranties.

ARTICLE VIII. LIMITATION OF THIRD PARTY RIGHTS

This Agreement is entered into solely for the benefit of the Company and the Choice Supplier and is not intended and should not be deemed to vest any rights, privileges or interests of any kind or nature to any third party, including, but not limited to the Customers that comprise Choice Supplier's Pool under this Agreement.

ARTICLE IX. SUCCESSION AND ASSIGNMENT

This Agreement shall be binding upon and inure to the benefit of the successors and assigns of the respective parties hereto. However, no assignment of this Agreement, in whole or in part, will be made without the prior written approval of the non-assigning party. The written consent to assignment shall not be unreasonably withheld.

ARTICLE X. APPLICABLE LAW AND REGULATIONS

This Agreement shall be construed under the laws of the State of Pennsylvania and shall be subject to all valid applicable State, Federal and local laws, rules, orders, and regulations. Nothing herein shall be construed as divesting or attempting to divest any regulatory body of any of its rights, jurisdiction, powers or authority conferred by law.

ARTICLE XI. NOTICES AND CORRESPONDENCE

Written notice and correspondence to Company shall be addressed as follows:

UGI Utilities, Inc. – Gas Division

1 UGI Drive

Denver, PA 17517

Attention: Manager, Tariff & Supplier Administration

Email: EDI-GAS@UGI.COM

Written notices and correspondence to Choice Supplier shall be addressed as follows:

Name

Address

Attention:________________

Telephone:

Email:

Either party may change its address for receiving notices effective upon receipt, by written notice to the other party.

ARTICLE XII. MISCELLANEOUS

12.1 No modification of the terms and provisions of this Agreement shall be or become effective except by execution of written contracts or by modification of Company's Gas Service Tariff.

12.2. No waiver by any party of any one of more defaults by any other party of any provisions of this Agreement shall operate or be construed as a waiver of any subsequent or previous default or default, whether of a like or a different character.

12.3. In the event any tax or assessment is imposed, directly or indirectly, upon the gas tendered to, or received by Company for redelivery, Choice Supplier agrees to bear the amount of such tax or assessment. In the event that Company is required to pay such tax, Choice Supplier agrees to reimburse Company for such payment.

12.4. The subject heading of the articles of this Agreement are inserted for the purpose of convenient reference and are not intended to be a part of the Agreement nor considered in any interpretation of the same.

12.5. In the event of a conflict between the provisions of this Agreement and Company's Gas Service Tariff, the provisions of Company's Gas Service Tariff shall govern.

IN WITNESS WHEREOF, the parties hereto executed this Agreement on the day and year first above written.

ATTEST:	UGI UTILITIES, INC. – GAS DIVISION
__________________________	BY___________________________
ATTEST	CHOICE SUPPLIER
__________________________	BY___________________________

BOOK XI

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS EXHIBIT F – PROPOSED SUPPLEMENT NO. 32 TO UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S

UGI UTILITIES, INC. – GAS DIVISION – PA P.U.C. NOS. 7 & 7S SUPPLEMENT NO. 32

DOCKET NO. R-2021-3030218

Issued: January 28, 2022 Effective: March 29, 2022

UGI UTILITIES, INC. – GAS DIVISION

GAS TARIFF

INCLUDING THE GAS SERVICE TARIFF NO. 7

AND

THE CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Service and Choice Aggregation Service

in the

Territory Described Herein

Issued: January 28, 2022

Effective for service rendered on and after March 29, 2022.

Issued By:

Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This tariff makes Increases/Decreases/Changes to existing rates (see page 2-2(b)).

LIST OF CHANGES MADE BY THIS SUPPLEMENT
(Page Numbers Refer to Official Tariff)

Cover Page
- Updated to reflect Supplement Number, Notice language, Issue and Effective dates.

Table of Contents, Pages 3-4.
- Updated for all Tariff revisions detailed below.

Description of Territory, Pages 5-19.
- Description of Territories has been revised from the former South, North and Central rate districts to a consolidated rate district presentation.
- Pages 19(a) and 19(b) have been added as a pagination change and intentionally left blank.

Rule 5, Extension Regulation, Page 35.
- Subsection 5.1(b)(1) language has been modified to replace the "Company's Allowable Investment Amount" with the "Customer contribution amount".

Rule 10, Rider A, State Tax Adjustment Surcharge, Page 48.
- The State Tax Adjustment Surcharge rate has been reset to 0.00%.
- Rate GBM, which no longer exists, was removed from the applicable list of rates.

Rule 11, Rider B, Section 1307(f) Purchased Gas Costs, Page 50.
- Reference to 22A.6 has been renumbered as 22.6.

Rule 12, Rider C, Extended TCJA Temporary Surcharge, Pages 53-54.
- Rider C, Extended TCJA Temporary Surcharge has ended and has been removed and replaced with Rider C, Weather Normalization Adjustment.

Rule 13, Rider D, Merchant Function Charge, Page 55.
- The rate has increased for Residential PGC Customers to 2.27% and for Non-Residential PGC Customers to 0.44%.

Rule 15, Price to Compare, Page 57.
- The Price to Compare has changed as a result of the change to the Merchant Function Charge.

Rule 16, Rider F, Universal Service Program, Page 59.
- Annual Reconciliation – the CAP credit bad debt offset language has been updated and will be applied where CAP enrollment exceeds CAP enrollees as of September 30, 2022.

Rule 19, Distribution System Improvement Charge, Page 63.
- The rate has been reset to 0.00%.

Rule 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, Pages 81(a)-81(i)
- Section 22.A has been renumbered Section 22. All references to 22.A have been renumbered to 22.
- These pages have been repaginated. Previous pages 81(a)-81(i)have been renumbered as 73-81 which were previously intentionally left blank.

Rate R – General Service – Residential, Page 85.
- The Customer Charge and Distribution Charge have been increased.
- Rider C Extended TCJA Temporary Surcharge has ended and has been replaced with Rider C Weather Normalization Adjustment.

LIST OF CHANGES MADE BY THIS SUPPLEMENT - Continued
(Page Numbers Refer to Official Tariff)

Rate RT – General Service – Residential Transportation, Page 86.
- The Customer Charge and Distribution Charge have been increased.
- Rider C Extended TCJA Temporary Surcharge has ended and has been replaced with Rider C Weather Normalization Adjustment.

Rate GL – General Service – Gas Light Service, Page 88.
- The Distribution Charge has been increased.
- Rider C Extended TCJA Temporary Surcharge has ended and has been removed.
- Punctuation was corrected and a period was added following the word “modify” under Surcharges and Riders.

Rate N – General Service – Non-Residential, Page 89.
- The Customer Charge and the Distribution Charge have been increased and have been changed to reflect a unified distribution charge.
- Rider C Extended TCJA Temporary Surcharge has ended and has been replaced with Rider C Weather Normalization Adjustment.

Rate NT – General Service – Non-Residential Transportation, Page 90.
- The Customer Charge and the Distribution Charge have been increased and have been changed to reflect a unified distribution charge.
- Rider C Extended TCJA Temporary Surcharge has ended and has been replaced with Rider C Weather Normalization Adjustment.

Rate DS – Delivery Service, Pages 94.
- The Maximum Distribution Charge has been increased and has been changed to reflect a unified distribution charge.
- Rider C Extended TCJA Temporary Surcharge has ended and has been removed.

Rate NNS – No-Notice Service, Page 96-97.
- Terms and Conditions – Language that referenced terms prior to November 1, 2020 that was no longer applicable was removed.
- The unit cost per MCF has been recalculated and updated.

Rate MBS – Monthly Balancing Service, Page 98-98(a).
- Terms and Conditions – Language that referenced terms prior to November 1, 2020 that was no longer applicable was removed. In addition, Section 22A.2 has been renamed Section 22.2.
- The Rate MBS charged to Rates DS/IS, LFD, and XD has been recalculated and updated.

Rate LFD – Large Firm Delivery Service, Page 100.
- The Maximum Demand Charge and Distribution Charge have been increased.
- Rider C Extended TCJA Temporary Surcharge has ended and has been removed.

Rate XD – Extended Large Firm Delivery Service, Page 103.
- The Maximum Average Delivery Charge has been increased.
- Rider C Extended TCJA Temporary Surcharge has ended and has been removed.

Rate R/S – Retail and Standby Rider, Page 107.
- Rider C Extended TCJA Temporary Surcharge has ended and has been removed.

Rate IS – Interruptible Service, Page 110.
- Rider C Extended TCJA Temporary Surcharge has ended and has been removed.

LIST OF CHANGES MADE BY THIS SUPPLEMENT - Continued
(Page Numbers Refer to Official Tariff)

Choice Supplier Tariff

Cover Page
- Updated to reflect Supplement Number, Notice language, Issue and Effective dates.

Rule 4, Choice Supplier Obligations, Page 115.
- Subsection 4.12 – The residential and commercial Purchase of Receivable rates have been updated as a result of the change to the Merchant Function Charge.

Rule 7, Nomination Procedure, Page 118-119.
- Subsection 7.3 – Change made to correct capitalization of “Choice supplier” to “Choice Supplier”.
- Subsection 7.3 – Language has been removed that referenced a Maximum Daily Bundled Sale Percentages heading on the Company’s Energy Management website to reflect changes made to the Company’s Energy Management website navigation.
- Subsection 7.3 – Language has been removed that referenced a Must Take Monthly Bundled Sale Percentages heading on the Company’s Energy Management website to reflect changes made to the Company’s Energy Management website navigation.

Rule 9, Enrollment of Customers into Rate Schedules RT and NT, Page 125.
- Subsection 9.3 – Language was added to include enrollments processed in addition to enrollments received.

Rule 11, Aggregation Agreement for Rate Schedules RT and NT (Pro Forma), Page 136.
- Article XI – For written notice and correspondence to the Company, the Attention line has been updated to reflect the contact as Rates Department – Choice Administrator.
- Article XI – The line following “Attention” has been removed from the written notice and correspondence to Choice Supplier.

TABLE OF CONTENTS

(C) Indicates Change

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(C) Indicates Change

Description of Territories **(C)**

ADAMS COUNTY

Townships

Cumberland	Freedom

ARMSTRONG COUNTY

City

Parker

BEDFORD COUNTY

Boroughs

Bedford	Everett

Townships

Bedford	Colerain	Monroe
Napier	Snake Spring Valley	West Providence

BERKS COUNTY

City

Reading

Boroughs

Adamstown (part)	Bally	Birdsboro
Boyertown	Centerpoint	Fleetwood
Hamburg	Kenhorst	Kutztown
Laureldale	Leesport	Lyons
Mohnton	Mt. Penn	New Morgan
Robesonia	St. Lawrence	Shillington
Shoemakersville	Sinking Spring	Topton
Wernersville	West Reading	Womelsdorf
Wyomissing	Wyomissing Hills	

Townships

Alsace	Amity	Bern
Caernarvon	Centre	Colebrookdale
Cumru	Douglass	Exeter
Heidelberg	Hereford	Jefferson

(C) Indicates Change

Description of Territories - Continued **(C)**

Longswamp	Lower Alsace	Lower Heidelberg
Maiden Creek	Marion	Maxatawny
Muhlenberg	Ontelaunee	Perry
Richmond	Robeson	Rockland
Ruscombmanor	South Heidelberg	Spring
Tilden	Union	Washington
Windsor		

BLAIR COUNTY

Boroughs

Martinsburg	Roaring Spring

Townships

Huston	North Woodbury	Taylor
Woodbury		

BRADFORD COUNTY

Boroughs

Alba	Burlington	Canton
Sylvania	Troy	

Townships

Armenia	Burlington	Canton
Columbia	Granville	LeRoy
Ridgebury	Smithfield	South Creek
Springfield	Troy	Ulster
Wells	West Burlington	

BUCKS COUNTY

Boroughs

Perkasie	Quakertown	Richlandtown
Riegelsville	Sellersville	Silverdale
Trumbauersville		

Townships

Durham	East Rockhill	Haycock
Hilltown	Milford	Nockamixon
Richland	Springfield	West Rockhill

(C) Indicates Change

Description of Territories - Continued **(C)**

CARBON COUNTY

Boroughs

Bowmanstown	East Side	Jim Thorpe
Lehighton	Palmerton	Weissport

Townships

Banks	East Penn	Kidder
Lower Towamensing	Mahoning (part)	Packer

CENTRE COUNTY

Boroughs

Philipsburg	South Philipsburg

Township

Rush

CHESTER COUNTY

Borough

Oxford

Townships

East Coventry (part)	East Nottingham	Elk
Honey Brook (part)	Lower Oxford	North Coventry (part)
Upper Oxford	West Nottingham	

CLARION COUNTY

Boroughs

Callensburg	Silgo

Townships

Ashland	Beaver	Clarion
Elk	Farmington	Highland
Knox	Licking	Limestone
Millcreek	Monroe	Paint
Perry	Piney	Richland
Salem	Toby	Washington

(C) Indicates Change

Description of Territories – Continued **(C)**

CLEARFIELD COUNTY

Boroughs

Chester Hill	Clearfield and Environs	Curwensville
Wallaceton		

Townships

Boggs	Bradford	Decatur
Knox	Lawrence	Morris
Pike		

CLINTON COUNTY

City

Lock Haven

Boroughs

Avis	Beech Creek	Flemington
Mill Hall	Renovo	South Renovo

Townships

Allison	Bald Eagle	Beech Creek (portion)
Castanea	Chapman	Crawford
Dunnstable	Gallagher	Grugan
Noyes	Pine Creek	Wayne
Woodward		

COLUMBIA COUNTY

Boroughs

Berwick	Briar Creek	Centralia

Town

Bloomsburg

Townships

Briar Creek	Conyngham	Hemlock
Mifflin	Montour	Scott
South Centre		

(C) Indicates Change

Description of Territories - Continued **(C)**

CUMBERLAND COUNTY

Boroughs

Camp Hill	Carlisle	Lemoyne
Mechanicsburg	Mt. Holly Springs	New Cumberland
Shippensburg	Shiremanstown	West Fairview
Wormleysburg		

Townships

Dickinson	East Pennsboro	Hampden
Lower Allen	Middlesex	Monroe
North Middleton	Shippensburg	Silver Spring
Southampton	South Middleton	Upper Allen

DAUPHIN COUNTY

City

Harrisburg

Boroughs

Dauphin	Highspire	Hummelstown
Middletown	Paxtang	Penbrook
Royalton	Steelton	

Townships

Conewago	Derry (including Hershey)	East Hanover
Jackson	Jefferson	Lykens
Londonderry	Lower Paxton	Lower Swatara
Middle Paxton	Rush	South Hanover
Susquehanna	Swatara	West Hanover
Williams		

FOREST COUNTY

Borough

Tionesta

Townships

Barnett	Green	Harmony
Jenks	Tionesta	

(C) Indicates Change

Description of Territories – Continued (C)

FRANKLIN COUNTY

Boroughs

Orrstown	Shippensburg	Waynesboro

Townships

Greene (part)	Guilford (part)	Hamilton (part)
Letterkenny (Army Depot)	Southampton	Washington

FULTON COUNTY

Borough

McConnellsburg

Townships

Ayr (part)	Todd

HUNTINGDON COUNTY

Boroughs

Huntingdon	Mapleton	Mill Creek
Mount Union		

Townships

Brady	Henderson	Juniata
Oneida	Shirley	Smithfield
Union	Walker	

JEFFERSON COUNTY

Borough

Summerville

Township

Barnett

JUNIATA COUNTY

Townships

Tuscarora	Lack	Milford

(C) Indicates Change

Description of Territories – Continued (C)

LACKAWANNA COUNTY

Cities

Carbondale	Scranton

Boroughs

Archbald	Blakely	Clarks Green
Clarks Summit	Dalton	Dickson City
Dunmore	Jermyn	Jessup
Mayfield	Moosic	Moscow
Old Forge	Olyphant	Taylor
Throop	Vandling	

Townships

Abington	Benton	Carbondale
Clifton	Covington	Elmhurst
Fell	Glenburn	Greenfield
Jefferson	La Plume	Madison
Newton	North Abington	Ransom
Roaring Brook	Scott	South Abington
Spring Brook	West Abington	

LANCASTER COUNTY

City

Lancaster

Boroughs

Adamstown (part)	Akron	Columbia
Denver	East Petersburg	Elizabethtown
Ephrata	Lititz	Manheim
Marietta	Millersville	Mount Joy
Mountville	New Holland	Quarryville
Strasburg		

Townships

Brecknock	Caernarvon	Clay
Colerain	Conoy	Earl
East Earl	East Cocalico	East Donegal
East Drumore	East Hempfield	East Lampeter
Ephrata	Lancaster	Leacock

(C) Indicates Change

Description of Territories – Continued **(C)**

Little Britain	Manheim	Manor
Mount Joy	Paradise	Penn
Pequea	Rapho	Strasburg
Upper Leacock	Warwick	West Cocalico
West Donegal	West Earl	West Hempfield
West Lampeter		

LEBANON COUNTY

City

Lebanon

Boroughs

Cleona	Cornwall	Myerstown
Palmyra	Richland	

Townships

Annville	Bethel	Cold Spring
East Hanover	Jackson	Millcreek
North Annville	North Cornwall	North Lebanon
North Londonderry	South Annville	South Lebanon
South Londonderry	Swatara	Union
West Cornwall	West Lebanon	

LEHIGH COUNTY

Cities

Allentown	Bethlehem (part)

Boroughs

Alburtis	Catasauqua	Coopersburg
Coplay	Emmaus	Fountain Hill
Macungie	Slatington	

Townships

Hanover	Lower Macungie	North Whitehall
Salisbury	South Whitehall	Upper Macungie
Upper Milford	Upper Saucon	Washington
Weisenburg	Whitehall	

(C) Indicates Change

Description of Territories – Continued **(C)**

LUZERNE COUNTY

Cities

Hazleton	Nanticoke	Pittston
Wilkes-Barre		

Boroughs

Ashley	Avoca	Conyngham
Courtdale	Dallas	Dupont
Duryea	Edwardsville	Exeter
Freeland	Forty Fort	Harvey’s Lake
Hughestown	Kingston	Laflin (part)
Larksville	Laurel Run	Luzerne
Nescopeck	New Columbus	Nuangola
Pittston	Plymouth	Pringle
Shickshinny	Swoyersville	Sugar Notch
Warrior Run	West Hazleton	West Pittston
West Wyoming	White Haven	Wyoming
Yatesville		

Townships

Bear Creek	Buck	Butler
Conyngham	Dallas	Dennison
Dorrance	Exeter	Fairmount
Fairview	Foster	Franklin
Hanover	Hazel	Hollenback (part)
Hunlock	Huntington	Jackson
Jenkins (part)	Kingston	Lake
Lehman	Nescopeck	Newport
Pittston	Plains	Plymouth
Rice	Ross	Salem
Slocum	Sugarloaf	Union
Wilkes-Barre	Wright	

LYCOMING COUNTY

City

Williamsport

Boroughs

Duboistown	Hughesville	Jersey Shore
Montgomery	Montoursville	Muncy

(C) Indicates Change

Description of Territories – Continued **(C)**

Picture Rocks	Salladsburg	South Williamsport

Townships

Anthony	Armstrong	Bastress
Brady	Clinton	Eldred
Fairfield	Franklin	Hepburn
Jackson	Jordan	Limestone
Loyalsock	Lycoming	McNett
Mifflin (part)	Millcreek	Moreland
Muncy	Muncy Creek	Nippennose
Old Lycoming	Penn (part)	Piatt
Porter	Shrewsbury (part)	Susquehanna
Upper Fairchild	Washington	Wolf (part)
Woodward		

MCKEAN COUNTY

Boroughs

Eldred	Mount Jewett	Port Allegany

Townships

Annin	Ceres	Eldred
Hamlin	Keating	Liberty
Norwich	Otto	Sergeant

MIFFLIN COUNTY

Boroughs

Burnham	Juniata Terrace	Lewistown
McVeytown		

Townships

Armagh	Bratton	Brown
Decatur	Derry	Granville
Menno	Union	

MONROE COUNTY

Boroughs

Delaware Water Gap	East Stroudsburg	Mount Pocono
Stroudsburg		

(C) Indicates Change

Description of Territories – Continued **(C)**

Townships

Chestnuthill	Coolbaugh	Eldred
Hamilton	Middle Smithfield	Paradise
Pocono	Ross	Smithfield
Stroud	Tobyhanna	Tunkhannock

MONTGOMERY COUNTY

Townships

Douglass	New Hanover	Limerick (restricted)

MONTOUR COUNTY

Borough

Danville

Townships

Cooper	Liberty (part)	Limestone
Mahoning	Valley	

NORTHAMPTON COUNTY

Cities

Bethlehem (part)	Easton

Boroughs

Bangor	Bath	East Bangor
Freemansburg	Glendon	Hellertown
Nazareth	Northampton	North Catasauqua
Pen Argyl and Vicinity	Portland	Roseto
Stockertown	Tatamy	Walnutport
West Easton	Wilson	Wind Gap

Townships

Allen	Bethlehem	Bushkill
East Allen	Forks	Hanover
Lehigh	Lower Mount Bethel	Lower Nazareth
Lower Saucon	Palmer	Plainfield
Upper Mount Bethel	Upper Nazareth	Washington
Williams		

(C) Indicates Change

Description of Territories – Continued (C)

NORTHUMBERLAND COUNTY

Cities

Shamokin	Sunbury

Boroughs

Kulpmont	Marion Heights	Milton
Mount Carmel	Northumberland	Riverside
Snydertown	Turbotville	Watsontown

Townships

Coal	Delaware	East Cameron
East Chillisquaque	Jordan	Lewis Twp.
Little Mahanoy	Lower Augusta	Mount Carmel
Point	Ralpho	Rockefeller
Shamokin	Turbot	Upper Augusta
Washington	West Cameron	West Chillisquaque
Zerbe		

PIKE COUNTY

Borough

Milford

Townships

Dingman	Lehman	Milford
Westfall		

POTTER COUNTY

Boroughs

Austin	Bingham	Coudersport
Galeton	Hebron	Oswayo
Shinglehouse	Ulysses	

Townships

Abbott	Allegany	Clara
Eulalia	Genesee	Harrison
Hector	Hebron	Homer
Keating	Oswayo	Pike

(C) Indicates Change

Description of Territories – Continued **(C)**

Pleasant Valley	Portage	Roulette
Sharon	Summit	Sweden
Sylvania	Ulysses	West Branch
Wharton		

SCHUYLKILL COUNTY

City

Pottsville

Boroughs

Ashland	Auburn	Cressona
Deer Lake	Frackville	Gilberton
Girardville	Gordon	Landingville
McAdoo	Mechanicsville	Middleport
Minersville	Mount Carbon	New Philadelphia
Orwigsburg	Palo Alto	Port Carbon
Port Clinton	Ringtown	St. Clair
Schuylkill Haven		

Townships

Blythe	Branch	Butler
Cass	East Union	East Norwegian
Foster	Hubley	Kline
Mahanoy (part)	New Castle	North Manheim
Norweigan	Ryan	South Manheim
Union	Upper Mahantongo	West Brunswick
West Mahanoy		

SNYDER COUNTY

Boroughs

Selinsgrove	Shamokin Dam

Townships

Middlecreek	Monroe	Penn

SUSQUEHANNA COUNTY

Boroughs

Forest City	Uniondale

(C) Indicates Change

Description of Territories – Continued (C)

Townships

Auburn	Clifford

TIOGA COUNTY

Boroughs

Blossburg	Elkland	Knoxville
Lawrenceville	Liberty	Mansfield
Roseville	Tioga	Wellsboro
Westfield		

Townships

Bloss	Brookfield	Charleston
Chatham	Clymer	Covington
Deerfield	Delmar	Duncan
Elkland	Farmington	Gaines
Hamilton	Jackson	Lawrence
Liberty	Middlebury	Nelson
Osceola	Putnam	Richmond
Rutland	Shippen	Sullivan
Tioga	Union	Ward
Westfield		

UNION COUNTY

Borough

Lewisburg

Townships

Buffalo (part)	East Buffalo (part)	Gregg
Kelly (part)	Lewis	Union (part)
West Buffalo (part)	White Deer	

VENANGO COUNTY

City

Oil City

Boroughs

Rouseville	Sugarcreek

(C) Indicates Change

Description of Territories – Continued **(C)**

Townships

Clinton	Cornplanter	Cranberry
Pinegrove	President	Richland
Rockland		

WAYNE COUNTY

Boroughs

Bethany	Hawley	Honesdale
Waymart		

Townships

Berlin	Canaan	Cherry Ridge
Clinton	Dyberry	Oregon
Palmyra	Paupack	Texas

WYOMING COUNTY

Boroughs

Factoryville	Laceyville	Meshoppen
Nicholson	Tunkhannock	

Townships

Braintrim	Clinton	Eaton
Exeter	Falls	Forkston
Lemon	Mehoopany	Meshoppen
Monroe	Nicholson	North Branch
Northmoreland	Noxen	Overfield
Tunkhannock	Washington	Windham

YORK COUNTY

Townships

Fairview	Newberry	

(C) Indicates Change

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(C) Indicates Change

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(C) Indicates Change

RULES AND REGULATIONS

5. EXTENSION REGULATION

5.1 Obligation to Extend or Expand.

(a) Under the rules set forth below and under normal conditions of construction and installation, upon written application, the Company will extend or expand its facilities within its service territory, provided that (a) the requested extension or expansion will not adversely affect the availability or deliverability of gas supply to existing customers and (b) the Company's investment in facilities is warranted by the Annual Base Revenue to be derived from the extension. The costs of extending or expanding facilities beyond the Company’s Allowable Investment Amount shall be paid by the Extension Applicant as a contribution. Extension contributions may be excused, in whole or in part, in accordance with Rule 5.1(b). Upon request, the Company will provide Customers with a written explanation and reasonable detail of the cost-benefit analysis used in clause (b) above including estimated project costs, the Company’s maximum allowable investment, and the Company’s Annual Base Revenues. In addition, the Company will provide the Customer with a written timetable for the anticipated construction of the upgrade and written notice of completion.

(b) No contribution amount shall be required for an extension of facilities if all of the following conditions, as determined by the Company, are met:

(1) Service location is directly accessible from an existing or proposed (non-high pressure) Company main that would be extended up to one hundred fifty (150) feet;

(2) Service length is one hundred fifty (150) feet or less;

(3) Customer will utilize gas service as their primary heating source and be served under Rates R, RT, N or NT;

(4) Construction does not cross third party non-public property, private right-of-way or complex obstruction (stream, culvert, excessive hillside, etc.)and does not present any abnormal or unusual construction conditions or require unusual permitting requirements.

(5) Extensions not meeting all of the above conditions (1) through (4) shall have the Customer contribution amount determined upon incremental investment amount **(C)** required beyond those permitted by the construction conditions stated above.

(6) These modified extension provisions shall not be applied to customers along existing GET Gas designated mains nor be permitted as a method to extend existing GET Gas mains where GET Gas surcharge payments remain in effect.

(C) Indicates Change

RULES AND REGULATIONS

10. RIDER A

STATE TAX ADJUSTMENT SURCHARGE

The State Tax Adjustment Surcharge is applicable to the net monthly rates and minimum charges contained in this Tariff. The surcharge shown below will be recomputed when a tax rate used in the calculation changes and/or the Company implements a change in rates.

The recomputation of the surcharge will be submitted to the PUC within 10 days after the occurrence of a reason for surcharge recomputation shown above. If the recomputed surcharge is less than the one in effect the Company will, and if more may, submit a tariff or supplement to reflect such recomputed surcharge, the effective date of which shall be 10 days after the filing.

Rider A - State Tax Adjustment Surcharge is 0.00% **(D)**

This Rider applies to Rates R, RT, GL, N, NT, DS, and LFD. **(C)**

(D) Indicates Decrease **(C) Indicates Change**

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

As applicable, to the extent such charges are not directly paid, Purchased Gas Costs shall include credits related to the use of PGC capacity by transportation customers where the Customer or NGS utilizes Company assigned or released pipeline capacity. In addition, revenues related to balancing services provided pursuant to Sections 22.2 and 22.4; Rate NNS; Rate MBS; capacity or commodity gas sales made pursuant to Customer elections under the Retail Standby Rider; Unauthorized Overrun; OFO, DFD and NGS penalty charges and bundled city gas sales made to NGSs shall be credited to the PGC. Such credits shall be reduced annually by the Economic Benefit Peaking Supply (EBPS Credit)reductions calculated pursuant to Rule 22.6 of the Rules and Regulations. **(C)**

"E" - Experienced net overcollection or undercollection of purchased gas costs ("E-Factor"). Such net overcollection or undercollection statement shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. Each over-under collection statement shall also provide for refund or recovery of amounts necessary to adjust for over or underrecoveries of E factor amounts under the previous 1307(f)rate.

Interest shall be computed monthly at the rate provided for in Section 1307(f)(5) of the Public Utility Code from the month that the over or undercollection occurs to the effective month such overcollection is refunded or such undercollection is recouped.

Additionally, supplier refunds will be included in the calculation of "E" with interest added at the annual rate of six percent (6%) calculated in accordance with the foregoing procedure, beginning with the month such refund is received by the Company.

Computation and Application of the E-Factor

The E-Factor shall be computed to the nearest one-hundredth cent (0.01¢) per Mcf in accordance with the formula set forth below:

E-Factor = (-E/S)

Each E-Factor so computed shall be applied to customer's bill for a one (1) year period during the Computation Year.

"S" - Projected MCF of gas to be billed to Customers during the projected period when rates will be in effect.

(C) Indicates Change

RULES AND REGULATIONS

12. Rider C

WEATHER NORMALIZATION ADJUSTMENT **(C)**

Applicability and Purpose:
A Weather Normalization Adjustment ("WNA") shall be applied to bills of Residential and Non-Residential customers under Rate Schedules R, RT, N and NT, for any bills rendered during the heating season October through May.

WNA is a distribution charge adjustment and is considered a basic service charge.

Calculated WNA amounts shall be subject to Rider A – State Tax Adjustment Surcharge and Rider I – Distribution System Improvement Charge. No additional riders or surcharges will be applied to the calculated WNA.

Calculation of Adjustment Amount:
The WNA will be applied to October through May billing cycles and shall be calculated on a customer account specific basis in accordance with the formula below:

WNBC = BLMC + [(NHDD / AHDD) x (AMC-BLMC)]
WNAC = WNBC – AMC
WNA = WNAC x Distribution Charge

(a) Weather Normalized Billing Ccfs("WNBC") will be calculated as the Base Load Monthly Ccfs ("BLMC") added to the product of the Normal Heating Degree Days ("NHDD") divided by the Actual Heating Degree Days ("AHDD") and the Actual Monthly Ccfs ("AMC") less the BLMC. Weather Normalized Billing Ccfs (WNBC) will only be calculated if the AMC exceeds the BLMC. WNA will not be applicable for the billing period if AMC is less than the BLMC.

(b) BLMC shall be established for each customer using the customer's actual average daily consumption from the billing system, measured in Ccfs, using bills with read dates of June 21st thru September 20th over a thirty-six-month period multiplied by the number of days in the billing period. The average daily base load is recalculated monthly using the most recent thirty-six months of bill history. If less than twelve months of bill history is available for the premise, an average base load for the related customer class will be applied.

(c) AMC shall be measured for each customer and billing cycle and will be inclusive of any heating value corrections.

(d) NHDD shall be applied on a Delivery Region specific basis as determined by the customer's geographical location and, for any given day within a billing period, shall be based upon the Delivery Region's 15-year average for the given day. NHDD shall be updated every 5 years using the methodology established in the Company's general rate case proceeding at R-2021-3030218 with the next scheduled update of the NHDD to be effective on October 1, 2025, and thereafter every five years.

(C) Indicates Change

RULES AND REGULATIONS

12. Rider C - Continued

WEATHER NORMALIZATION ADJUSTMENT **(C)**

(e) AHDD shall be the actual experienced heating degree days during the billing cycle for the customer's assigned Delivery Region, as determined by the customer's geographical location. A Delivery Region's AHDD shall be based upon experienced actual Gas Day temperatures as reported by the National Oceanic and Atmospheric Administration (NOAA) for weather stations located within that Delivery Region pursuant to the application of the Company's established Delivery Region calculation methodology.

(f) The period for which both NHDD and AHDD will be measured for each billing period used for the WNA calculation will be based on the starting day of the customer's billing cycle minus one day through last day of billing cycle minus one day. If AHDD is unavailable for any day(s) during that period, the respective NHDD for the same day(s) will also be excluded from the calculation, thereby excluding any days missing AHDD from the WNBC calculation.

(g) AMC will be subtracted from the WNBC to compute the Weather Normalized Adjustment Ccfs ("WNAC").

(h) The WNAC shall then be multiplied by the applicable Rate Schedule Distribution Charge based on service rendered to compute the WNA amount that will be charged or credited to each Residential and Non-Residential customer served under Rate Schedules R, RT, N and NT.

(i) In the event a customer's bill needs to be canceled and rebilled at any time, the WNA will be recalculated using the most recently available data for the billing period. In some cases, updates in data used in the calculation, may result in a different WNA for the billing period. Bills requiring manual processing shall not have WNA applied.

(j) The Company will file a report detailing weather normalization information with the Commission annually by December 1st for the preceding twelve-month period ending September 30th.

(C) Indicates Change

RULES AND REGULATIONS

13. RIDER D

MERCHANT FUNCTION CHARGE

Applicability and Purpose

This Rider shall be applied to rates for each MCF (1,000 cubic feet) of gas supplied under Rate Schedules R and N of this Tariff and shall be reflected in the Price to Compare. The Rider is equal to the fixed percentage, established by the PUC in Company’s last general base rate proceeding, of purchased gas costs which are expected to be uncollectible, and shall not be reconciled to reflect actual results. Rider D is intended to make Company’s Price to Compare more comparable to the gas supply service prices offered of other Natural Gas Suppliers that presumably reflect anticipated uncollectible expenses.

Rider D Charge

Rider D charges shall be equal to 2.27% for Residential PGC Customers and 0.44% Non-Residential PGC Customers of Rider B (Purchased Gas Costs). **(I)**

The collection of the Rider D charges will be summarized by Rate Schedule sub-accounts in the Gas Operating Revenue FERC Account No. 480000 for Rate R and 481000 for Rates N. The associated costs are recorded in FERC Account Nos. 904001 and 904002.

(I) Indicates Increase

RULES AND REGULATIONS

15. PRICE TO COMPARE

The Price to Compare ("PTC") is composed of the Annual C-Factor, Annual E-Factor, Gas Procurement Charge and Merchant Function Charge. The PTC rate will change whenever any components of the PTC change. The current PTC rate is detailed below:

Price to Compare

	Rate R (CCF)	**Rate N (MCF)**	
Annual C-Factor	$ 0.59486	$ 5.9486	
Annual E-Factor	$ 0.03281	$ 0.3281	
Gas Procurement Charge	$ 0.00660	$ 0.0660	
Merchant Function Charge	$ 0.01425	$ 0.0276	**(I)**
Total Price to Compare	$ 0.64852	$ 6.3703	**(I)**

(I) Indicates Increase

RULES AND REGULATIONS

16. RIDER F - Continued

UNIVERSAL SERVICE PROGRAM

QUARTERLY ADJUSTMENT

Any time that the Company makes a change in base rates or PGC rate affecting residential customers, the Company shall recalculate the Rider USP rate pursuant to the calculation described above to reflect the Company's current data for the components used in the USP rate calculation. The Company shall file the updated rate with the PUC to be effective one (1) day after filing.

ANNUAL RECONCILIATION **(C)**

On or before November 1 of each year, the Company shall file with the PUC data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended September. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the CAP quarterly rate adjustment to be effective December 1. Actual recoverable costs shall reflect actual CAP costs, actual application costs, actual pre-program arrearage forgiveness, actual LIURP and actual Hardship Administrative costs. Actual recoverable CAP credit costs and pre-program arrearage forgiveness shall be based upon actual CAP credits granted and pre-program arrearage forgiveness granted less a 9.2% adjustment for amounts granted to participants in excess of the number of CAP enrollees as of September 30, 2022. The 9.2% adjustment related to CAP credits and pre-program arrearage forgiveness will be based on the following:

For each reconciliation period, the average annual CAP credit per participant will be determined by dividing the total actual CAP credits granted during the reconciliation period by the average monthly number of participants receiving CAP credits during the reconciliation period. The average monthly number of participants receiving CAP credits exceeding the number of CAP enrollees as of September 30, 2022 will be multiplied by the average annual CAP credit granted per participant and then multiplied by 0.0920 in order to determine the amount of the CAP Credits which will not be recovered through Rider USP.

For each reconciliation period, the average pre-program arrearage forgiveness per participant will be determined by dividing the total actual pre-program arrearage forgiven during the reconciliation period by the number of participants receiving pre-program arrearage forgiveness. The number of participants receiving pre-program arrearage forgiveness exceeding the number of CAP enrollees as of September 30, 2022 will be multiplied by the average pre-program arrearage forgiveness per participant and then multiplied by 0.0920 in order to determine the amount of the pre-program arrearage forgiveness which will not be recovered through Rider USP.

(C) Indicates Change

RULES AND REGULATIONS

19. Rider I

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC)

In addition to the net charges provided for in this Tariff, a charge of 0.00% will apply. **(D)**

19.A.1 Purpose. To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not recoverable through the DSIC.

19.A.2 Eligible Property.

The DSIC-eligible property will consist of the following:

- Piping, Couplings, Valves, Excess Flow Valves, Risers - Distribution & Transmission. (374, 376, 365, 367)
- Measuring & Regulator Stations – Distribution & Transmission (375, 378, 379, 366, 369, 370)
- Gas Service Lines and Insulated and Non-Insulated Fittings (378, 380)
- Meters, Meter Bars, Meter Installations (381, 382)
- House Regulators & Installations (383, 384)
- Industrial & Farm Tap Measuring & Regulator Station Equipment (385, 386)
- Miscellaneous Equipment and Material– Distribution & Transmission (387, 371)
- Equipment – Electronic Systems & Software (391)
- Vehicles, Power Equipment, Tools, Shop & Garage Equipment (392, 394, 396)
- Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities.
- Gathering lines (332)
- Storage lines (353)
- Other related capitalized costs.

19.A.3 Computation of the DSIC. The DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update.

(D) Indicates Decrease

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS (C)
Effective November 1, 2020

22.1 Application of Rates **(C)**

(a) Applicable Rates: DS, LFD, XD and IS.

(b) Notification of Delivery; Nomination Procedures. Customer shall notify the Company of any and all gas deliveries to the Company's system, including, but not limited to, the provision of nomination, revised nomination and scheduling information, in accordance with the Company's *Nomination Procedure*, as may be amended from time to time, and made available on the Company's Gas Management Website ("Nomination Procedure"). The quantity of gas received on behalf of the Customer shall be determined by allocation or other method by the Company if required in its sole discretion. It is the Customer's responsibility to arrange that any necessary billing information be provided to the Company and/or delivery gas source.

(c) Nominating Agents. A Customer shall notify the Company of its designated nominating agent ("Agent") for purposes of nominating the volumes of natural gas to be delivered to the Company's system on the Customer's behalf in accordance with the Nomination Procedures. Customer shall notify Company, on a form designated by the Company in the Nomination Procedures, of the responsibilities of the Agent, and shall provide Company with the Agent's valid e-mail address and valid 24-hour contact information. Customer shall remain liable for all charges and penalties notwithstanding Customer's designation and use of an Agent in accordance with the provisions herein.

(d) Penalties for Customer's Default. Customers failing to provide nomination, billing, scheduling, agent, supplier and/or other required information to the Company or pipeline(s)in accordance with the provisions of the Tariff, or otherwise failing to comply with the Company's *Nomination Procedure*, shall be subject to applicable imbalance charges and, in addition, be charged an Administrative Scheduling Fee in an amount no greater than $1,000 per day for every day such required information is delayed. If a Customer default of these provisions occurs and is occurring for a period of 90 days, the Company may impose retail or standby rates on the Customer's account beginning the first day after such 90-day period through and until such time as the Company deems the Customer default to have been resolved.

(e) Sequencing for Billing. Unless otherwise agreed by the Company and the Customer, customer-owned gas delivered under the transportation rate schedules shall be sequenced for billing as the first gas through the meter, and gas purchased under the Retail and Standby Rider shall be sequenced for billing purposes as the last gas through the meter. Gas billed under firm rate schedules shall be billed prior to gas billed under interruptible rate schedules. In lieu of otherwise specified tariff provisions, where the Company and Customer agree, Company shall use pipeline metering facilities for measuring and billing total deliveries to the Customer's facility.

(C)Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued **(C)**

(f) Payment of Charges, Penalties. The Customer shall pay the Company for any and all additional charges incurred on the Customer's behalf or resulting from the Customer's actions or inactions which the Company can demonstrate arise out of the provision of transportation service including, but not limited to, pipeline transportation and service charges. Any such charge, penalty or obligation imposed by a pipeline transporter or supplier as result of balancing of gas delivered to the Customer shall be paid by the Customer in addition to otherwise applicable charges.

(g) The Billing Pool Agent is required to notify Company at least ten days prior to dropping a Customer from a Billing Pool. If adequate advance notice is not provided, the Company reserves the right to not drop the Customer from the Billing Pool.

(h) Billing Pools. One or more transportation Customers may join together in pooled transactions for the purchase and delivery of gas. The Company may allocate among all such customers the volumes of gas or imbalances for purposes of determining responsibility for charges, rates, penalties or other obligations imposed by the Company, or in connection with operation of the pool. A Supplier to a Billing Pool must notify the Company prior to initiating gas deliveries. A Customer is required to submit in writing a request for entry into a Billing Pool.

(1) Each Billing Pool shall appoint an Agent who will coordinate nomination, billing, reconciliation, allocation and any other necessary communication between the Billing Pool and the Company.

(2) All members of a Billing Pool shall be of like balancing service election. The Company may restrict formation or operation of any Billing Pool in order to meet like balancing service election or pipeline imposed eligibility requirements.

(3) Automated Meter Reading. The Company has the right as a condition of being a pool member, to install, at the Customer's expense, automated meter reading ("AMR") equipment for the purposes of daily collection or monitoring, and billing Customer volumes at each related service meter. Where AMR equipment is installed, the Customer shall maintain, at its expense, unless otherwise directed by the Company, a dedicated phone connection and electric service to the AMR equipment which will allow the Company unlimited remote access to the AMR device at all times. Failure to maintain a required phone and/or electric service may result in Customer being removed from a Billing Pool and being placed on a rate schedule not requiring daily measurement capability.

(4) Service under Rate NNS is required by, and shall be individually billed to, any and all members of a Billing Pool except when all pool members are monitored on a daily basis through the use of Company owned AMR equipment at all meter locations. Additionally, service under Rate MBS is required by, and shall be individually billed to, any and all members of a Billing Pool when the billing month for each pool member does not end on the same calendar date; Billing Pools having all customers monitored and billed through the use of Company owned AMR equipment at all meter locations shall be exempt from this requirement.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued **(C)**

(i) Recognition of Supplies. Volumes transported on behalf of the Customer will be recognized in the Customer's current billing month based on nominated or scheduled volumes information and may be adjusted after notification is received from the pipeline supplier(s) of the volumes transported on behalf of the Customer. Volumes scheduled shall be determined on the basis of best available actual or confirmed pipeline and/or Company information at the time of billing.

(j) Unless otherwise negotiated under Rate XD, the Company shall retain for Company use gas, and lost and unaccounted for gas, 1.0% of the total volume of gas delivered into its system for the Customer's account.

22.2 Balancing and No-Notice Service. **(C)**

(a) Each Customer shall use best efforts to balance purchases, deliveries and receipts of gas at all times. Except as specified in 22.1(f), for the purposes of balancing excess deliveries and shortfalls and purchasing services under Rates NNS and MBS, Billing Pools may be treated as a single entity. Subject to the terms and conditions set forth below, the Company shall provide no-notice and monthly balancing services under Rate Schedules NNS and MBS. Service under Rate Schedules NNS and MBS is available only for inadvertent fluctuations, limited by the terms and conditions of each Rate Schedule, and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided. In the event the Customer fails to use best efforts to balance deliveries and receipts, or otherwise misuses no-notice or balancing services as determined by the Company in its sole discretion, Section 22.4 shall apply for the period of such default or misuse.

(b) Daily Balancing. The Company shall allow Customer's daily demand to inadvertently vary from daily scheduled deliveries by +/-4.5% without imposing Daily Balancing Charges, provided the total daily quantity taken does not exceed Customer's Daily Firm Requirement, MDQ or otherwise specified contract demand limit. Daily imbalances in excess of the +/-4.5% tolerance, unless otherwise provided by service elected under Rate NNS, shall be assessed a Maximum Daily Excess Balancing Charge in accordance with Section 22.4 under Critical Day and Non-Critical Day criteria unless otherwise specified in Customer's contract, in addition to the charges specified in Rates DS, LFD, XD and IS, on all such quantities.

(c) Imbalance Resolution. Customer's monthly imbalances will be calculated at the end of each billing period to determine if any overdelivery (excess) or underdelivery (shortfall) condition exists for volumes scheduled versus volumes metered. If the Customer is determined to be in an imbalance condition, and has not elected service under Rate MBS or has exceeded the 10% imbalance allowance provided under Rate MBS, then the Company shall sell and the Customer shall buy, subject to the 5 percent limitation under Rate MBS, any shortfall amount according to the following cash-out pricing:

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued **(C)**

Shortfall Percent	Cash-Out Price
Up to 5%	Shortfall Monthly Index(“SMI”)
Greater than 5%, but not greater than 15%	SMI x 1.1
Greater than 15%, but not greater than 25%	SMI x 1.3
Greater than 25%	SMI x 1.5

Likewise, the Customer shall sell, and the Company shall buy any excess amount according to the following cash-out pricing:

Excess Percent	Cash-Out Price
Up to 5%	Excess Monthly Index (“EMI”)
Greater than 5%, but not greater than 15%	EMI x 0.9
Greater than 15%, but not greater than 25%	EMI x 0.7
Greater than 25%	EMI x 0.5

The SMI (Shortfall Monthly Index) shall be the average of the published *Gas Daily* Midpoint index prices corresponding to the Customer’s Delivery Region during the Customer’s billing month as listed below:

Delivery Region	Index
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The EMI (Excess Monthly Index) shall be the average of the published *Gas Daily* Midpoint index prices corresponding to the Customer’s Delivery Region during the Customer’s billing month as listed below:

Delivery Region	Index
North	Tennessee, zone 4-300 leg
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

Customer Delivery Region shall be assigned to each Customer in accordance with Customer's delivery location within the Company's distribution system.

The SMI and EMI are applicable to the above tables only for inadvertent monthly imbalances. The HMI (Highest Monthly Index) or the LMI (Lowest Monthly Index) as defined below shall apply respectively to shortfall and excess conditions in those situations where intentional imbalances are involved.

The HMI shall be calculated as the highest of the published *Gas Daily* Absolute index prices for the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	Index
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The higher of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The LMI shall be calculated as the lowest published *Gas Daily* Absolute prices for the Customer's Delivery Region during the Customer's billing month as listed below:

Delivery Region	Index
North	Tennessee, zone 4-300 leg PLUS the applicable transportation costs from Tennessee, zone 4 to zone 4.
Central	The lower of Transco, zone 6 non-N.Y. or Transco, Leidy Line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The lower of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C)Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued **(C)**

(d) The Company may extend the balancing period for gas volumes and may increase volumes eligible for balancing in its discretion, but only if it determines that such action is consistent with its obligations to other customers.

(e) Supply Transfers. In order to facilitate Monthly balancing related to inadvertent imbalances in Company’s sole discretion, the Company shall allow Supply Transfers among Customers and Billing Pools, Customers-to-Billing Pools and Billing Pools-to-Customers at a fee of $125 per transaction, provided however: (1) such transfer is requested prior to the end of the billing month for both the transferee and the transferor, (2) such transfer is physically possible given pipeline interconnection and delivery point limitations which require transfers to be between parties located on the same segment of the Company’s distribution system, and system supplies, and reliability are not adversely affected.

(f) Competitive Volume Customers. In the case of Customers or applicants seeking service for facilities with a design volume capability allowing for direct connection to transmission or gathering lines for bypass of Company facilities, Company shall have the right to establish daily and monthly balancing tolerances at levels other than those specified in subsections (b) and (c) of this Section 22.2 to reflect specific operational limitations or to protect the interests of other Customers, as determined by the Company in its sole discretion. Additionally, the Company may establish special nomination rules, imbalance resolution rules and communication protocols that reflect the Customer’s or applicant’s commercial alternatives, and which are consistent with its obligations to other Customers.

22.3 Service Agreement and General. **(C)**

(a) Limitation on Liability.

(1) The Company shall not be liable for curtailment of service under Rates DS, LFD, XD and IS, or loss of the Customer's gas as a result of any steps taken to comply with any law, regulation or order of any governmental agency with jurisdiction to regulate, allocate or control gas supplies or the rendition of service hereunder, and regardless of any defect in such law, regulation or order.

(2) Gas transported and delivered by the Company to the Customer hereunder shall be and remain the property of the Customer. The Customer shall be responsible for maintaining all insurance it deems necessary to protect its property interest in such gas before, during and after receipt by the Company.

(3) The Company shall not be liable for any loss to the Customer arising from or out of service hereunder, including loss of gas in the possession of the Company or any other cause, except gross or willful negligence of the Company's own employees or agents. The Company reserves the right to commingle gas of the Customer with other supplies.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

(b) Warranty, indemnity and special provisions. The receipt of service constitutes Customer's agreement to the following representations and warranties, together with related provisions in the service agreement:

(1) clear and marketable title to the Customer's gas;
(2) delivery points, pressure, quality and other specifications acceptable to gas transmission pipeline(s) and the Company;
(3) eligibility of the Customer for service;
(4) existence of lawful authority for sale, transportation and delivery;
(5) agreement to pay all excise, sales, use, gross receipts, or other taxes (other than income taxes), all tariff charges and all penalties, charges, fees for transportation, balancing etc., associated with delivered gas, which may be levied upon or incurred by the Company at any time;
(6) agreement to indemnify and hold the Company harmless from breach of representations or warranties, and any liability associated with Customer's gas while on the Company's system.

Copy of Gas Purchase Agreements, Other Documents. When requested by the Company, the Customer shall provide the Company with a copy of Customer's gas purchase contract and any related transportation, marketing and brokerage contracts, or, in lieu of providing such contracts, certify pertinent information as required by the Company, and, in order to meet state or federal requirements, provide a sworn affidavit setting forth the Customer's cost of gas for the period requested by the Company. The Company shall endeavor to protect the confidentiality of information provided by the customer in accordance with this provision. The Company will provide such information to third parties only when required to do so by law, regulation or order and in such case, will attempt to maintain confidentiality to the extent possible.

22.4 Maximum Daily Excess Balancing Charge **(C)**

The Daily Excess Balancing Charge that occurs on Critical Days shall be as follows:

The charge for exceeding daily balancing limits shall be ten times the highest price as published in *Gas Daily* on the table “Daily Price Survey.” For each delivery region as listed in the table below. This rate shall not be lower than the maximum penalty charge for unauthorized daily overruns as provided for in the FERC-approved gas tariffs of the interstate pipelines which deliver gas into Pennsylvania.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued (C)

Delivery Region	**Index**
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.
Central	The higher of 1) Transco, zone 6 non-N.Y. or 2) Transco, Leidy Line receipts plus the applicable transportation costs from Transco Zone 6 to Zone 6.
South	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	The higher of Texas Eastern, M-3 or Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

The Daily Excess Balancing Charge that occurs on Non-Critical Days shall be as follows:

Daily Imbalance Percent	Penalty
Up to 15%	GDI
Greater than 15%, but not greater than 30%	GDI x 2
Greater than 30%, but not greater than 45%	GDI x 3
Greater than 45%, but not greater than 60%	GDI x 4
Greater than 60%	GDI x 5
Intentional imbalances	GDI x 5

The GDI (Gas Daily Index) shall be equal to the difference in price between the highest published *Gas Daily* index price and the lowest published *Gas Daily* index price for the Customer’s Delivery Region as listed below but shall not be lower than $0.25/Mcf.

Delivery Region	**Highest Index Price**	**Lowest Index Price**
North	Tennessee, zone 4- 300 leg plus the applicable transportation costs from Tennessee Zone 4 to Zone 4.	Tennessee, zone 4- 300 leg
Central	Transco zone 6, non-N.Y.	Transco, Leidy line receipts plus the applicable transportation costs from Transco zone 6 to zone 6.
South	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.
West	Texas Eastern, M3	Texas Eastern, M-2 receipts plus the applicable transportation costs from Texas Eastern M-2 to M-3.

(C) Indicates Change

RULES AND REGULATIONS

22. GENERAL TERMS FOR DELIVERY SERVICE FOR RATE SCHEDULES DS, LFD, XD, AND IS Effective November 1, 2020 – Continued **(C)**

The Company shall not charge any Maximum Daily Excess Balancing Charges if the Customer's Excess Daily Imbalance is anticipated to benefit the distribution systems daily balancing position as determined by Company in its sole discretion.

22.5 Operational Flow Orders and Daily Flow Directives **(C)**

The Company has the right to issue Operational Flow Orders and Daily Flow Directives at any time. Failure to comply with any OFO or DFD shall result in a penalty charge of Twenty-Five ($25) per Mcf or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater.

22.6 Cost of Assigned Capacity. **(C)**

In addition to applicable interstate pipeline demand charges, the associated demand charges to customers, or their NGS, served under Rates DS and LFD, and who utilize assigned PGC capacity, will include 100% and 50% pro rata allocation of annual Peaking Supply service demand costs, respectively. The associated demand charges will be reduced by a pro rata share of the Economic Benefit of Peaking Supply (EBPS Credit). The EBPS Credit shall mean a pro rata share of (a) the value of Peaking Supply utilized in off system sales transactions and included in the PGC share of the Revenue Sharing Incentive Mechanism revenues, plus (b) the Commodity Price Differential, which shall be, as measured for the date of Peaking Supply delivery, the aggregate difference, if positive, between the Gas Daily price applicable to the zone of delivery (i.e., Texas Eastern M3 for deliveries in the South and West Delivery Regions with the exception of deliveries from Mt. Bethel and Transco Z6 NNY for deliveries made in the North and Central Delivery Regions and deliveries from Mt. Bethel) and the actual price paid for actual Peaking Supply deliveries into the UGI distribution system. The EBPS Credit shall be applied in the calculation of associated demand charges in the second billing month after the credit has accrued (e.g., December accrued credits will be used to reduce the February associated demand charges) and shall not, on an annual basis, exceed the annual incremental demand charges for Peaking Services charged to Rate DS and LFD customers, or their NGS, as described above.

(C) Indicates Change

RATE R

GENERAL SERVICE – RESIDENTIAL

AVAILABILITY

This rate applies to all Residential Customers in the entire gas service territory of the Company and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company’s gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $19.95 per customer **(I)**

Plus Distribution Charge: $0.49996/Ccf **(I)**

Plus SURCHARGES and RIDERS
- Rider A – State Tax Adjustment Surcharge
- Rider B – Section 1307 (f) Purchased Gas Cost
- Rider C – Weather Normalization Adjustment **(C)**
- Rider D – Merchant Function
- Rider E – Gas Procurement Charge
- Rider F – Universal Service Program
- Rider G – Energy Efficiency and Conservation
- Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT

In accordance with Section 8.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(I) Indicates Increase (C) Indicates Change

RATE RT

GENERAL SERVICE – RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies to all Residential Customers in the entire gas service territory who are served by a qualified Choice Supplier receiving service under Rate AG and available at one location, for the total requirements of any residential Customer. Residential Customers are customers receiving the Company's gas service to a single-family dwelling or building, or through one meter to four or fewer units in a multi-family dwelling or premises used as a single family.

MONTHLY RATE TABLE

Customer Charge: $19.95 per customer **(I)**

Plus Distribution Charge: $0.49996/Ccf **(I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C - Weather Normalization Adjustment **(C)**
Rider F - Universal Service Program
Rider G – Energy Efficiency and Conservation
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase (C) Indicates Change

RATE GL

GENERAL SERVICE - GAS LIGHT SERVICE

AVAILABILITY

This service is available for street, highway, driveway or other lighting or sign illumination, where measurement by meter of the gas consumed is not practicable or economical. As used herein, “light” means a single lamp or sign having one (1) gas-flow orifice and one (1) or more mantles, and of a type approved by the Company.

MONTHLY RATE TABLE

Distribution Charge: $0.49996/Ccf **(I)**

Plus

SURCHARGES and RIDERS **(C)**

Rider A - State Tax Adjustment Surcharge
Rider B – Section 1307(f) Purchased Gas Cost
Rider I – Distribution System Improvement Charge

Monthly usage is assumed to be 1.8 Mcf, however, for larger consumption input fixtures, the Company reserves the right to modify. **(C)**

BILLS DUE

All bills for continuing service are due each month when rendered, and the final due date stated on the bill shall be no less than fifteen (15) days from the date of presentation. Upon discontinuance of service, bills are due and payable upon presentation.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

SPECIAL TERMS AND CONDITIONS

Gas will be supplied to lights furnished, erected and maintained by the customer only when equipped with regulators and such devices as the Company considers necessary for turning lights on and off for maintenance and safety purposes.

(I) Indicates Increase (C) Indicates Change

RATE N

GENERAL SERVICE – NON-RESIDENTIAL

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Non-Residential Customers, using gas for any purpose including gas purchased by another public utility for resale. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate N service may not be applied to supplement or back up any transportation service.

MONTHLY RATE TABLE
Customer Charge: $30.00 per customer **(I)**

Plus Distribution Charge: $4.0413/Mcf **(C,I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider B - Section 1307(f) Purchased Gas Cost
Rider C – Weather Normalization Adjustment **(C)**
Rider D – Merchant Function Rider
Rider E – Gas Procurement Charge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE
The Customer Charge as set forth above.

MINIMUM BILL PROVISION
If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

PAYMENT
In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(I) Indicates Increase (C) Indicates Change

RATE NT

GENERAL SERVICE – NON-RESIDENTIAL TRANSPORTATION

AVAILABILITY

This Rate applies in the entire territory served by the Company and is available to all Customers who are served by a Choice Supplier receiving service under Rate AG, except residential Customers, using gas for any purpose. Service will be supplied only where the Company's facilities and the available quantity of gas are suitable to the service desired. Rate NT service may not be applied to supplement or back up any transportation or retail service.

MONTHLY RATE TABLE

Customer Charge: $30.00 per customer **(I)**

Plus Distribution Charge: $4.0413/Mcf **(C,I)**

Plus SURCHARGES and RIDERS

Rider A - State Tax Adjustment Surcharge
Rider C – Weather Normalization Adjustment **(C)**
Rider G – Energy Efficiency and Conservation
Rider H - Technology and Economic Development
Rider I – Distribution System Improvement Charge

MINIMUM CHARGE

The Customer Charge as set forth above.

MINIMUM BILL PROVISION

If natural gas service is discontinued at the request of the Customer, the Company shall not be under any obligation to resume service to the same Customer at the same premise within twelve months unless it shall receive an amount equal to the minimum charge for each month up to a maximum of twelve months of the intervening period.

Customer at the same premise who requires seasonal service and has gas shut off and turned on within twelve-month period billed in an amount equal to the minimum charge under the applicable rate for each month service was shut off up to the 12-month intervening period.

(I) Indicates Increase (C) Indicates Change

RATE DS

DELIVERY SERVICE

AVAILABILITY

This service applies in the entire territory served by the Company. Firm Delivery Service shall be provided for all volumes supplied by the Customer for which the Company has available on system delivery capacity, subject to Section 21 - Gas Emergency Planning provisions of the Company's tariff, applicable rules and regulations of the PUC and any other governmental mandates.

The Customer must execute a Service Agreement for not less than (1) one year. The contract shall continue in force for consecutive (1) year periods unless cancelled by the Customer upon ninety (90) days written notice to Company prior to the expiration of a contract term.

Gas service in excess of volumes delivered by the Customer shall only be provided in accordance with applicable delivery service balancing provisions or in accordance with optionally elected and approved balancing or standby services.

Service under Rate DS is subject to the terms set forth under Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Capacity Charge if applicable, and the Distribution Charge as described below. The following are maximum rates.

Customer Charge: $260.00 per month

Plus Capacity Charge: The Company's unitized weighted average cost of firm transportation capacity per elected MDQ.

Plus Maximum Distribution Charge: $2.9977/Mcf **(C, I)**

Plus

SURCHARGES and RIDERS **(C)**

Rider A - State Tax Adjustment Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I – Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

(I) Indicates Increase (C) Indicates Change

RATE NNS

NO-NOTICE SERVICE

AVAILABILITY

This Rate is available upon request to any Customer served on Rate DS, LFD, XD or IS who, after review and acceptance of such request by Company, has entered into a service agreement with Company for service under Rate NNS. The term of the service agreement shall be concurrent with that of the Customer's underlying Delivery Service Schedule.

Service under this Rate is available for inadvertent fluctuations only and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided.

Service to large volume users, such as electric generation facilities, may be limited as determined by the Company. Service under Rate NNS is subject to the terms and conditions set forth under Section 22 General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS.

TERMS AND CONDITIONS **(C)**

Customers shall elect a specific level of no-notice service under this Rate. Such election shall be made through the specification of a No-Notice Allowance ("NNA"), in MCF per day, of an amount no less than 4.5% and no greater than 100% of Customer's Daily Firm Requirement, Maximum Daily Quantity or otherwise specified daily contract limit. The elected NNA shall be effective for a fixed period equal to the lesser of one year or the remaining balance of the Customer's service agreement or, a lesser time period mutually agreeable to both the Customer and the Company. In no instance shall a NNA be effective for a period of less than one month. Rate NNS service elections in excess of 4.5%, are interruptible.

No-notice service shall be provided under this Rate whereby the Company shall forward or bank no-notice supplies to the Customer on a daily basis in such amounts necessary to balance the Customer's daily deliveries with the Customer's daily consumption. Forwarded amounts shall be limited in amount by the lesser of the sum of the Customer's daily nomination plus elected NNA or, the Customer's DFR, MDQ or otherwise specified contract limit except as allowed. Banked amounts shall be limited to an amount no greater than the Customer's NNA election.

Customer electing an NNA shall be billed for no-notice service according to that specific level of service.

Volumes in excess of the daily limits shall be subject to Daily Excess Imbalance Charges as set forth in Section 22.4 General Terms For Delivery Service for Rate Schedules DS, LFD, XD and IS on all such excess quantities, in addition to the charges specified in the Customer's Delivery Service Schedule.

(C) Indicates Change

RATE NNS - Continued

NO-NOTICE SERVICE

EXCESS REQUIREMENT OPTION

The Excess Requirement Option is available on an interruptible basis to any delivery service Customer served under Rates XD, LFD. This Option shall extend the no-notice provisions of Rate NNS, on solely a best efforts basis, during periods where Customer's daily requirements exceed transportation contract service limits.

Customer must nominate a Daily Excess Requirement ("DER") under this Option in an amount no less than 5 Mcf per day and no greater than 25% of Customer's DFR or otherwise specified contract limit. On days where service under the Excess Requirement Option is required, Customer will have the right, subject to the terms and conditions set forth herein, to take gas in excess of Customer's DFR or otherwise specified contract limit provided such excess is no greater than the nominated DER amount.

Service taken in excess of the sum of Customer's DFR and DER on any day shall be considered Excess Take or Unauthorized Overrun as determined by Customer's Delivery Service Schedule and service agreement.

Unauthorized gas forwarded or returned to the Company by the Customer shall be considered imbalance gas and shall be subject to either the balancing provisions set forth under Section 22.2 of General Terms for Delivery Service for Rate Schedules DS, LFD, XD and IS or the Customer's otherwise applicable transportation balancing service.

MONTHLY RATE TABLE (Basic NNS Service)

$0.1860 per Mcf per day of elected NNA **(C,I)**

plus

MONTHLY RATE TABLE (Excess Requirement Option)

$4.50 per Mcf per day of elected DER.

(C) Indicates Change (I) Indicates Increase

RATE MBS

MONTHLY BALANCING SERVICE

AVAILABILITY

This Rate is available upon request to any Customer served on Rate DS, LFD, XD or IS who, after review and acceptance of such request by Company, has entered into a Service Agreement with Company for service under Rate MBS. The term of the Service Agreement shall be concurrent with that of the Customer's underlying Rate Schedule.

Service under Rate MBS is available for inadvertent fluctuations only, limited to an amount not to exceed 10% of the customer's total scheduled deliveries for the month, and is not available to speculate as to fuel prices or otherwise to permit imbalances which reasonably could have been avoided. Service under Rate MBS is subject to the terms set forth in Section 22 General Terms For Delivery Service for Rate Schedules DS, LFD, XD, and IS.

Rate MBS is available as a monthly banking service for Customer transportation deliveries. Service under Rate MBS allows Customer transportation imbalances (metered volumes less total scheduled nominations) which are within 10% of Customer's total scheduled nominations for the month to be carried forward in the Customer's MBS Account ("Balance Account") for redelivery of excesses or receipt of shortfalls in subsequent months.

TERMS AND CONDITIONS

Balance Account Operation. To the extent Customer's total deliveries exceed Customer's total consumption at the end of a Billing Month, the excess volumes shall be added to the Customer's Balance Account. To the extent Customer's total consumption exceeds Customer's total deliveries at the end of a Billing Month, the shortfall volumes shall be subtracted from the Customer's Balance Account.

Balance Account Limits. At no time, as calculated at the end of a Billing Month, shall a Customer exceed a Balance Account excess or shortfall balance greater than 10% of the Customer's total scheduled deliveries for the month, as determined by the Company in its sole discretion. Any such imbalance over 10% (excess or shortfall) shall be subject to the Cash-in/Cash-out pricing set forth in Section 22.2 for monthly imbalance volumes in excess of 5%, with the remaining imbalance volumes to be carried over into the calculation of the Customer’s imbalance volumes for the following month. **(C)**

The Company, in its sole discretion, may zero out the Customer's Balance Account at the end of any Billing Month by purchasing or selling such net imbalance volumes in the Customer's Balance Account at the prevailing month's Cash-In/Cash-Out pricing at set forth in Section 22.2, provided such zero out may occur only if necessitated by operational needs of the Company or as a result of a requirement of an applicable interstate pipeline.

(C) Indicates Change

RATE MBS - Continued

MONTHLY BALANCING SERVICE

MONTHLY RATE TABLE

Monthly Transportation Volume

Rate DS/IS	$0.0437/Mcf x Monthly Billed Volumes	**(I)**
Rate LFD	$0.0263/Mcf x Monthly Billed Volumes	**(I)**
Rate XD	$0.0221/Mcf x Monthly Billed Volumes	**(I)**

The Company will update the average monthly imbalance utilized in the development of Rate MBS charges annually with the actual average monthly imbalance for the 12-month period ending September to determine the new Rate MBS charges effective December 1 each year. The Company shall include the new Rate MBS charges as part of its annual PGC compliance filing.

(I) Indicates Increase

RATE LFD - Continued

LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be the sum of the Customer Charge, the Demand Charge, the Distribution Charge and any Excess Take Charge as described below. The following are maximum rates.

Customer Charge: $670.00

Plus
Maximum Demand Charge: $5.9965/Mcf of Customer’s elected DFR. **(I)**

Plus
Maximum Distribution Charge: $1.2386/Mcf (all volumes) **(I)**

Plus
SURCHARGES and RIDERS **(C)**

Rider A - State Tax Adjustment Surcharge
Rider G – Energy Efficiency and Conservation
Rider H – Technology and Economic Development
Rider I - Distribution System Improvement Charge
Rider J – Gas Delivery Enhancement Rider

RETAINAGE RATE

Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, AND IS, paragraph 22.1(j).

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

EXCESS TAKE CHARGE

Except as provided in the Company's *Nomination Procedure*, for authorized usage on any day in excess of the Daily Firm Requirement there will be a charge of $6.00 per MCF in addition to the charges specified in the rate table.

(C) Indicates Change (I) Indicates Increase

RATE XD -Continued

EXTENDED LARGE FIRM DELIVERY SERVICE

MONTHLY RATE TABLE

The charge for each monthly billing period shall be negotiable and shall be the sum of the Customer Charge, Distribution Charge, Demand Charge if applicable, and the Minimum Annual Bill as described below.

The following are maximum rates.
Customer Charge: Charge as determined by negotiation.

Plus
Maximum Demand Charge: Charge as determined by negotiation.

Plus
Maximum Average Delivery Charge: $1.2386/Mcf **(I)**

Plus
SURCHARGES and RIDERS **(C)**

Rider I – Distribution System Improvement Charge

RETAINAGE RATE

Unless otherwise agreed between the Customer and the Company, Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, and IS, paragraph 22.1(j)

MINIMUM BILL

Minimum Bill Volumes and terms shall be defined in the Service Agreement and determined by negotiation.

CHARGE FOR OTHER TRANSPORTATION

If the Customer chooses to use the Company as agent in regard to transportation service by others, any costs calculated by or billed to the Company, with regard to such agency, shall be billed to the Customer by the Company and may include an applicable administrative fee as agreed by the Customer and Company.

(C)Indicates Change (I) Indicates Increase

RATE R/S - Continued

RETAIL AND STANDBY RIDER

The minimum monthly bill under this rate schedule shall be the sum of the Customer and Capacity/Reservation Charges plus any commodity reservation costs per MCF of NSR.

SURCHARGES **(C)**

Rider I – Distribution System Improvement Charge

Any charges or penalties imposed by pipeline suppliers as a result of usage under this rider shall, at the Company's sole discretion, be allocated to Customers according to each Customer's contractual obligation or be assigned to the Customer responsible for the incurrence of the charges or penalties.

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

(C)Indicates Change

RATE IS - Continued

INTERRUPTIBLE SERVICE

Unless the Company otherwise agrees, the Minimum Annual Bill shall be calculated at the end of any Service Agreement period, anniversary, or termination of service in accordance with terms of the Service Agreement. Volumes of natural gas taken under Standby Service during the Service Agreement period shall be credited to the Minimum Annual Bill volumes.

SURCHARGES and RIDERS **(C)**

Rider I – Distribution System Improvement Charge

PAYMENT

In accordance with Section 8 of this Tariff.

LATE PAYMENT CHARGE

Late Payment Charges shall be billed in accordance with Section 8, Billing and Payment, paragraph 8.7.

CHARGE FOR UNAUTHORIZED OVERRUN

Whenever it is necessary to restrict gas supplied under this Rate, the Company will provide due notice of such restriction. If a Customer, after having received due notice of restriction, shall take gas in excess of the amount made available by such notice, then Customer shall be billed for such excess gas at the rate of Fifty Dollars ($50.00) per MCF, or the charge calculated in compliance with Section 22.4 Maximum Daily Excess Balancing Charge, whichever is greater, plus the charge specified in the monthly rate table. Customer shall indemnify Company from any claims by third parties resulting from Customer's unauthorized overrun.

Gas delivered under the Rate IS or purchased under the Cash-Out provisions of Section 22.2 or the Retail and Standby Rider or taken under Rate NNS shall be included in the determination of Unauthorized Overrun gas.

RETAINAGE RATE

Company Use and Unaccounted For gas shall be retained in accordance with Section 22, General Terms for Delivery Service for Rate Schedules DS, LFD, XD, AND IS, paragraph 22.1(j).

(C)Indicates Change

UGI UTILITIES, INC. - GAS DIVISION

GAS CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules

Governing the

Furnishing of

Gas Aggregation Service

Issued: January 28, 2022

Effective for service rendered on and after March 29, 2022.

Issued By:

Paul J. Szykman
Chief Regulatory Officer
1 UGI Drive
Denver, PA 17517

https://www.ugi.com/tariffs

NOTICE

This supplement makes changes to existing rates(see page 2).

RULES AND REGULATIONS

4. CHOICE SUPPLIER OBLIGATIONS

4.12 If a Choice Supplier elects to participate in the Company's POR Program, the Choice Supplier must enter into a POR Agreement for the rate classes that it serves that will be included in the POR. The elected Rate Classes shall be one of the following: (1) RT only, (2) NT only, or (3) RT and NT. All receivables associated with basic natural gas supply services in the specific rate class, subject to the rate class elections made above, must be sold by the participating Supplier to the Utility. For the purposes of this provision, the phrase "basic natural gas supply services" shall include charges directly related to the physical delivery of natural gas to a retail customer but shall not include charges for "carbon-neutral" products, appliance maintenance service, energy efficiency services, termination or cancellation fees, security deposits or other products or services not directly related to the physical delivery of natural gas to a retail customers. Customer accounts that are billed for non-basic natural gas supply services will not be eligible for UGI's POR program. All of the NGS' customer accounts within the elected Rate Classes (subject to the volumetric limits contained in section 5.4) must be POR eligible accounts, with the exception of customers that purchase carbon-neutral products. NGSs may choose to use UGI consolidated billing for Non-POR eligible customers who are purchasing bundled "carbon-neutral" product offerings. The termination and reconnection provisions of Chapters 14 and 56 of the Public Utility Code and PUC regulations shall not be applicable to unpaid NGS charges for non-POR eligible accounts on consolidated billing. NGSs will be responsible for collecting unpaid NGS charges on non-POR eligible accounts on consolidated billing. UGI shall support rate-ready billing, and all NGS rates must conform to supported rate designs. For Purchased Customer Accounts, Company shall pay Choice Supplier an amount equal to 97.59% for residential amounts billed **(C)** (inclusive of associated sales taxes) and 99.42% of non-residential amounts **(C)** billed (also inclusive of taxes). Customer participation for NT shall be subject to Volumetric Eligibility pursuant to Section 5.4.

4.13 All existing customers of Choice Suppliers who elect to participate in the Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier and Company that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

All new customers enrolling with Choice Suppliers who are participating in Company's optional Purchase of Receivables program shall be provided notice by the Choice Supplier prior to enrollment, and by Company upon enrollment, that (a) the Company will be providing one bill for all Company and Choice Supplier charges, (b) all payments should be made to the Company, (c) any unpaid amounts shall be subject to late payment charges, (d) the Company may request a security deposit for amounts which include Choice Supplier charges and (e) the Company maintains the right to terminate service for any unpaid Company or Choice Supplier charges, pursuant to Pennsylvania Public Utility Code regulations.

(C) Indicates Change

RULES AND REGULATIONS

7. NOMINATION PROCEDURE

7.1 Customer Choice Nomination Procedure. The Nomination Procedure specifies requirements for nominating, scheduling, balancing, and communicating information relating to Choice Supplier’s gas deliveries for customers served under Rates RT and NT.

7.2 Contact Persons. A list of Company contact persons will be posted on the Company’s Web Site, located at https://ugi.outsystemsenterprise.com/UGIContacts_FO/, or its successor, along with their department affiliation, email address, and telephone number.

7.3 Mandatory Assignment. As used in this tariff the term “Firm Commodity Supply Alternative” shall mean a Company purchase of natural gas, delivered directly to its distribution system or at points along Company pipeline capacity routes (Commodity Delivery Points), constituting a component of Company’s PGC supply portfolio and an alternative to pipeline capacity contracts upstream of the Commodity Delivery Points or other firm sources of PGC supply. Firm Commodity Supply Alternative contractual arrangements may require the payment of demand charges or minimum take requirements. Except as provided below, Choice Supplier **(C)** shall be required to accept releases of Company pipeline capacity combined with bundled city gate sales and, as applicable, peaking sales of gas from Company and sales of gas associated with Firm Commodity Supply Alternative arrangements, in accordance with the following assignments:

A monthly release of interstate pipeline capacity or allocation of Firm Commodity Supply Alternative in an amount equal to forty-three percent (43%) of the Peak Day Delivery Requirement (“PDDR”) of the Choice Customers served by the Choice Supplier during the month shall be released or allocated at a price equal to the projected weighted average demand cost of all PGC capacity, storage, peaking and Firm Commodity Supply Alternative assets, divided by .283. Effective November 1, 2020, to the extent the full Firm Commodity Supply Alternative is not fully nominated by Choice Supplier to satisfy its DDR, the remaining daily quantity may be nominated to a non-Choice transportation customer or pool of non-Choice transportation customers.

The Company shall also provide Choice Suppliers with a must-take Monthly Bundled Sale Quantity (“MBSQ”) during each winter month of November through March, and the Choice Supplier would be permitted to nominate and purchase gas at the Company’s city gates throughout each winter month, subject to the Maximum Daily Quantity (“MDQ”) limits, up to the MBSQ. The MDQ equals twenty-one percent(21%) of the PDDR of the Choice Customers served by the Choice Supplier during the month multiplied by the percentage shown on the Company’s Energy Management website. The minimum daily quantity is zero. Choice Suppliers are required to **(C)** nominate to the Company a daily quantity for bundled sales no later than 2:00 P.M. Eastern Prevailing Time on each Intercontinental Exchange (“ICE”) trading day for deliveries applicable to the ICE flow dates. If no nomination is received, the nomination quantity would default to zero. The Company reserves the right to issue Operational Flow Orders (“OFO”) that can modify the daily bundled sale MDQ or require certain levels of deliveries from the released firm transportation contracts. These OFOs would be issued for operational reasons only. MBSQs would be based on the Company’s storage withdrawal plan, to be updated annually, and communicated as a percentage of each Choice Supplier’s pre-month normalized

(C) Indicates Change

RULES AND REGULATIONS

7. NOMINATION PROCEDURE - CONTINUED

delivery requirements, which will be shown on the Company's Energy Management website. **(C)**

If the full MBSQ is not nominated and purchased by the end of each such winter month, the shortfall ("Bundled Sale Cash-In quantity") would be purchased by the PGC ("Bundled Sale Cash-In amount") as follows:

a. The DDR Variation Percentage is the sum of the actual DDRs experienced by a Choice Supplier divided by the sum of the pre-month average DDRs that was used to calculate the MBSQ, converted to a percentage. For any month where the DDR Variation Percentage is greater than ninety percent (90%), the Bundled Sale Cash-In amount would equal (1) the product of (a) 0.90 times the lowest absolute low for the Texas Eastern, M-2 receipts index price as published in Platts' Gas Daily for the applicable month of flow minus (b) the summer index price used for bundled sales (the "Bundled Sale Cash-In index") times (2) the Bundled Sale Cash-In quantity. If the resulting amount is positive, it would be credited to the Choice Supplier, or if negative, would be billed to the Choice Supplier.

b. In recognition of the effects of extreme warm weather conditions, shortfall amounts would be purchased as follows under such conditions:

   i. For any month where (a) the DDR Variation Percentage is less than or equal to ninety percent(90%) and (b) the Bundled Sale Cash-In quantity is less than or equal to the MBSQ minus the product of the DDR Variation Percentage times the MBSQ, then the Bundled Sale Cash-In amount would equal (1) the First of the Month Price called "Columbia Gas Transmission Corp., Appalachia" as published in Platts' Gas Daily Price Guide ("Inside FERC") for the month subsequent to the applicable month in which the Bundled Sale Cash-In quantity was created minus the summer index price used for bundled sales (the "Alternate Bundled Sale Cash-In Index") times (2) the Bundled Sale Cash-In quantity. If the resulting amount is positive, it would be credited to the Choice Supplier, or if negative, would be billed to the Choice Supplier.

   ii. For any month where (a) the DDR Variation Percentage is less than or equal to ninety percent (90%) and (b) the Bundled Sale Cash-In quantity is greater than the MBSQ minus the product of the DDR Variation Percentage times the MBSQ, then the Bundled Sale Cash-In amount would equal (1) the Alternate Bundled Sale Cash-In Index, as defined in Section 7.3.b.i, times the DDR Variation Percentage times the MBSQ plus(2) the Bundled Sale Cash-In Index, as defined in Section 7.3.a,times the difference of the Bundled Sale Cash-In quantity minus the product of the DDR Variation Percentage times the MBSQ. If the resulting amount is positive, it would be credited to the Choice Supplier, or if negative, would be billed to the Choice Supplier.

(C) Indicates Change

RULES AND REGULATIONS

9. ENROLLMENT OF CUSTOMERS INTO RATE SCHEDULES RT AND NT

9.1 To be served under Rate Schedules RT and NT, a Customer must be enrolled by the Choice Supplier elected by the Customer. Such enrollment by the Choice Supplier must be provided in an electronic file to the Company via an approved internet-based EDI transaction. The requirement filed shall include:

a. The customer's name;
b. The customer's address;
c. The customer's Company account number;
d. The specific transaction;
e. The elected billing option.

9.2 Company Confirmation. Company will electronically confirm receipt of the enrollment information and within one (1) business day and subsequently provide an electronic validation of the Choice Supplier's transmitted information.

9.3 Determination of Gas Flow Date. For enrollments received and processed on or **(C)** before the 15th of any calendar month, the customer will be switched to Rate Schedule RT and NT, where the customer does not respond within 5 days from the Company's mailing of a letter confirming the election to be served by the Choice Supplier, on the Customer's regularly scheduled meter reading date in the calendar month immediately following the month the enrollment information was received and processed. For enrollments received and processed after the 15th **(C)** of any calendar month, the customer will be switched to Rate Schedule RT and NT, where the customer does not respond within 5 days from the Company's mailing of a letter confirming the election to be served by the Choice Supplier, on the Customer's regularly scheduled meter reading date in the second calendar month following the month the enrollment information was received and processed. **(C)**

(C) Indicates Change

ARTICLE XI. NOTICES AND CORRESPONDENCE

Written notice and correspondence to Company shall be addressed as follows:

UGI Utilities, Inc. – Gas Division

1 UGI Drive

Denver, PA 17517

Attention: Rates Department – Choice Administrator **(C)**

Email: EDI-GAS@UGI.COM

Written notices and correspondence to Choice Supplier shall be addressed as follows:

Name

Address

Attention: **(C)**

Telephone:

Email:

Either party may change its address for receiving notices effective upon receipt, by written notice to the other party.

(C) Indicates Change

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 1-R

Rebuttal Testimony of
Christopher R. Brown

Topics Addressed:	**Overview of Company's Rebuttal Case** **Impact of Inflation on Company's Costs** **Management Performance** **Average Bill Comparison** **NRG Issues** **Heat Content Adjustment Programming Cost** **Issues Impacting Competitive Customers** ***Pro Se* Complainants and Public Input Hearings**

Dated: May 17, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher R. Brown. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 1, on January 28, 2022.

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to certain portions of the direct testimony and exhibits of: (1) Bureau of Investigation and Enforcement ("I&E") witnesses Anthony Spadaccio (I&E St. No. 2) and Ethan H. Cline (I&E St. No. 4); (2) Office of Consumer Advocate ("OCA") witnesses Dante Mugrace (OCA St. No. 1), David J. Garrett (OCA St. No. 2), Jerome D. Mierzwa (OCA St. No. 3), and Roger D. Colton (OCA St. No. 4); (3) Office of Small Business Advocate ("OSBA") witness Robert D. Knecht (OSBA St. No. 1); (4) NRG Energy, Inc. ("NRG") witness Christopher Reyes (NRG St. No. 1). I also respond to witnesses who testified during the April 13, 2022 Public Input Hearings.

Q. Are you sponsoring any exhibits as part of your rebuttal testimony?

A. Yes, I am sponsoring UGI Gas Exhibits CRB-1R and CRB-2R.

II. OVERVIEW OF COMPANY'S REBUTTAL CASE

Q. Would you please provide a summary of the Company's rebuttal testimony?

A. The Company's rebuttal testimony responds to each of the individual issues raised by the opposing parties. In some limited instances, the Company has agreed with the opposing party positions. However, for the most part, the other parties' arguments are factually wrong, reflect a misapplication or rejection of basic ratemaking principles, conflict with long-standing Pennsylvania Public Utility Commission ("Commission") precedent, or all of the above.

Q. Please describe the positions taken by other parties in response to UGI Gas's proposed revenue increase.

A. UGI Gas requested an $82.7 million increase in annual operating revenues, although the Company's most recent data and updates within rebuttal now justify an increase of $87.6 million. By comparison, I&E proposed a revenue increase of $18,072,000, and OCA proposed a revenue decrease of ($38,673,989). OSBA does not undertake an analysis to support a revenue requirement in Mr. Knecht's direct testimony.

Q. Are the revenue requirement amounts proposed by I&E and OCA reasonable?

A. No. I&E's and OCA's proposals simply do not reflect the facts or sound application of fundamental ratemaking principles. Further, the revenue requirements offered by I&E and OCA would significantly hinder the Company's ability to provide safe and reliable service to customers. UGI Gas will invest approximately $795 million during the future test year ("FTY") and the fully projected future test year ("FPFTY") in infrastructure and business systems to ensure that its service is safe, reliable, and customer-focused. Therefore, either the limited rate increase (as proposed by I&E) or the significant rate decrease (as proposed by OCA) would not support core functions of UGI Gas as a natural gas utility, the many jobs supported by the Company's capital program, or the positive economic impacts associated with the Company's work.

Q. How did the parties reach their lower revenue requirement recommendations?

The biggest differences in the revenue requirement recommendations are driven by: (1) unreasonable adjustments to the return on equity and capital structure; (2) reductions to budgeted plant in service investments made in error or lacking sound basis; (3) invalid adjustments to projected revenues; (4) improper adjustments to projected operating expenses; and (5) adjustments to the Company's cash working capital claim, which rely on flawed operating expense adjustments. Many of their witnesses' recommendations are founded on significant deviations from the standard ratemaking principles historically applied by the Commission. All of the I&E and OCA recommendations are fully addressed by the Company's witnesses in their rebuttal testimony.

III. IMPACT OF INFLATION ON THE COMPANY'S CASE

Q. Are there any economic conditions impacting the Company's operations that have changed since the base rate case filing was made in January?

A. Yes. In particular, inflation has significantly increased in recent months, and continues to do so. The material impacts of this inflation must be called out here as an important matter. The consumer price index ("CPI") jumped 8.5% in March 2022 from 12 months earlier, the sharpest year-over-year increase in over 40 years (since 1981).[1] Just recently, the April 2022 inflation numbers were reported to be 8.3%. As a result, the Company is proposing several key inflation-related adjustments in its rebuttal case and highlighting the impacts in key areas where adjustment could be made but the Company has chosen not to do so.

Q. Please identify the inflation related adjustments included as part of the Company's rebuttal position that impact the overall claim in this case.

A. The Company has seen escalating costs due to increased inflationary and other economic factors affecting the Company's operations. Specifically, the cost of future issuances of long-term debt will result in higher interest rates than the data from January 2022 that was reflected in the filed case, as further discussed by Paul R. Moul in his rebuttal testimony (UGI Gas St. No. 6-R). Additionally, Timothy J. Angstadt (UGI Gas St. No. 9-R) will discuss and quantify the FPFTY claim impacts of increased contractor costs that the Company is now experiencing based on recent request for proposal responses and contract negotiations that occurred after the January filing. The impact of these two adjustments on the Company's updated revenue requirement claim is approximately $7.1 million.

Q. Are there any other adjustments that you are making related to the current amount of inflation in the economy?

A. No, but I would like to note that as discussed in my direct testimony, the Company is experiencing increased turnover in its employee ranks, and the increasing inflation has caused the Company to continue to look at additional ways to address the impacts to our

[1] https://www.bls.gov/news.release/cpi.nr0.htm

employees. As a result, since the time of the original filing in this case, the Company is preparing an enhanced merit increase program to be rolled out later this year.

Q. Please describe the enhanced merit increase program that is being considered by the Company and why it was developed.

A. The Company reviewed unemployment rates, inflation impacts including the CPI, as well as nationwide pay trends.[2] The national pay increase surveys indicate that average salary increases are near five percent annually, substantially higher than the three percent budgeted merit increase that the Company has in its FY23 budget. The Company has developed a proposal to increase the targeted merit increase amount to five percent annually, or a total increase of two percent over the current budgeted levels of three percent. The increase would impact employees other than those who are covered by collective bargaining agreements. This two percent increase equates to an additional $960,000 to the Company's FPFTY anticipated operating expenses (after the removal of 17 positions from the Company's budget as proposed by OCA Witness Mugrace, and further discussed in the rebuttal testimony of Tracy Hazenstab (UGI Statement No. 2-R)).

Q. Is the Company increasing its as filed claim for the $960,000 related to this anticipated change?

A. No. The Company is not including this as an adjustment in its overall rebuttal testimony updates and revenue requirement calculation. However, to the extent the Commission decides that any salary and wages adjustments are warranted, the Company requests that

[2] The World at Work salary budget survey, Pearl Meyer survey, and Mercer's Global Comp Planning Report.

the Commission consider the additional $960,000 in merit increase expenditures as an offset to any further downward salary and wage adjustments in this case.

Q. Do you have any further thoughts on the impact of inflation on the Company's operations?

A. Inflation has broad and pervasive impacts on the Company's operations and is expected to touch almost every daily activity that UGI Gas undertakes. However, the Company is not proposing numerous specific adjustments for the anticipated increased operating expenses related to inflation, other than those noted above. I believe the Commission should consider the overall economic climate and these inflationary pressures on the cost of goods and services that the Company procures as part of providing safe and reliable service when deciding the merits of the Company's requested base rate increase. Additionally, the Commission should be aware that the Company's exposure to inflationary forces outside the areas it has quantified above represents increased financial risk for the Company and further supports the Company's claimed cost of equity, as discussed in Mr. Moul's rebuttal testimony.

IV. MANAGEMENT PERFORMANCE

Q. Do any parties oppose the Company's proposed 20 basis point adjustment to the equity return for management effectiveness?

A. Yes. I&E and OCA both recommend no adjustment to the equity return to recognize the Company's management effectiveness.

Q. Please summarize I&E's reasons for rejecting the proposed management effectiveness adjustment.

A. On page 48 of I&E Statement No. 2, Mr. Spadaccio claims that the management performance items detailed in my direct testimony "fall within the categories of reliability, customer satisfaction, and safety, which are required of every public utility company under 66 Pa. C.S.A. § 1501." (I&E St. No. 2 at 48). Mr. Spadaccio also claims that public utility companies should not be rewarded in any fashion for goodwill through additional basis points in a rate case. Specifically, he states "if the Company is effective at controlling operating and maintenance costs, those savings should flow through to ratepayers and/or investors." (*Id*.)

Q. Please summarize OCA's basis for rejecting the proposed management effectiveness adjustment.

A. On page 70 of OCA Statement No. 2, Mr. Garrett similarly rejects any return on equity ("ROE") related to management performance. He calls the 0.2% ROE management adjustment a "premium." However, he provides no support that the Commission considers management performance-related ROE amounts to be premiums. While he alleges that the 0.2% portion of the ROE is arbitrary and unsupported, he offers no testimony to counter the Management Effectiveness and Performance section in my direct testimony (UGI Gas St. No. 1), which supports and justifies the 0.2% adjustment. Instead, he focuses on a prior Commission decision to justify his conclusory position. Specifically, Mr. Garrett testifies that the Commission rejected a management performance adjustment in a recent UGI Gas case. He states:

> In the last rate case for the UGI Gas division, UGI Gas proposed a 25-basis point premium for management effectiveness. The Commission found that 'such an upward adjustment is contrary to the public interest.' The Company's management performance claim in this case encompasses activities commenced as early as 2010 or projected to occur well past the end of the FPFTY. Similarly, communications tools implemented by UGI in 2015 and 2018 came several years after introduction by another Exelon affiliate.

(OCA St. No 2 at 70-71.)

Q. Do you have any initial response to this quoted testimony from Mr. Garrett?

A. There are several problems with this part of Mr. Garrett's testimony. First, the Commission case he cites to does not involve UGI Gas. He cites to a PECO Energy Company ("PECO") case at Docket No. R-2020-3018929, wherein PECO sought a 25-basis point adjustment to its ROE. While he calls it a UGI Gas case in his citation, he is referring to a PECO case. That is evidenced in the above quote where he claims that communication tools were implemented several years after introduction by another Exelon affiliate. Exelon and PECO are affiliates. UGI Gas and Exelon are related in no way and are not affiliates. Moreover, while Mr. Garrett claims that the Commission found that PECO's request for a management performance based adder was contrary to the public interest (based on his above quoted language), neither the Commission nor the administrative law judge made that conclusion in the PECO case and instead drew a conclusion that was limited to the facts of the case. Mr. Garrett's testimony quoted above is incorrect and misleading and should be wholly rejected.

Q. Do you have a response to I&E's and OCA's contention that the Company should not benefit from management performance items because they relate to the Company's regulatory obligation to provide safe and reliable service?

A. Yes. First, it appears that I&E and OCA simply disagree with Pennsylvania law, and in particular the provisions of 66 Pa. C.S. § 523, which gives the Commission specific authority to consider management performance in setting base rates including, in the case of Natural Gas Distribution Companies ("NGDCs"), "[a]ction or failure to act to encourage development of cost-effective energy supply alternatives" as well as "other relevant and material evidence of efficiency, effectiveness and adequacy of service." While the witnesses from I&E and OCA are certainly correct that reliability, customer satisfaction, and safety are all critical elements of UGI Gas's provision of utility service to customers, it is clear that Pennsylvania law allows the Commission to consider the Company's exceptional performance in those areas.

Q. Has the Commission recently exercised its authority under Section 523 of the Public Utility Code?

A. Yes, the Commission recently awarded a management incentive addition to UGI Utilities, Inc. – Electric Division's ("UGI Electric's") cost of equity in UGI Electric's base rate case at Docket No. R-2017-2640058. In that proceeding the Commission stated:

> [W]e are persuaded by the arguments of UGI that its management performance related to its implementation of a voluntary LTIIP, a fully voluntary EE&C Plan, programs focusing on enhancing customer satisfaction, and initiatives related to workforce safety and training is laudable and warrants consideration as a factor in our final cost of equity allowance. The unrebutted record evidence indicates that UGI has been consistently recognized for high customer satisfaction. Additionally, UGI has consistently exceeded its benchmark service reliability metrics …

Opinion and Order entered Oct. 4, 2018 at 114.

Q. Does UGI Gas have many of the same types of programs and attributes as those identified in the Commission's Order related to UGI Electric?

A. Yes, it does. UGI Gas has filed a voluntary Long-Term Infrastructure Improvement Plan ("LTIIP") and a voluntary Energy Efficiency and Conservation ("EE&C") Plan. The Company has undertaken a variety of programs to improve customer service and increase the safety of its employees and the public. And, like UGI Electric, UGI Gas has exceptional customer satisfaction performance, including placing first or second in customer satisfaction in J.D. Power awards over multiple years. The accomplishments highlighted in my direct testimony are the kind that this Commission has considered in the recent past as indicating a management performance adder is appropriate.

Q. I&E and OCA assert that the accomplishments you have identified do not justify a management performance adder. Please respond.

A. Both I&E and OCA are simply wrong in concluding that the many Company initiatives outlined on pages 30-39 of my direct testimony, supporting the proposed management efficiency adjustment, are the minimum actions required to provide safe and reliable service under 66 Pa.C.S. §1501. As the Commission recognized in the above-quoted passage from the UGI Electric 2018 base rate case, the implementation of an LTIIP and EE&C Plan are not the minimum actions. Instead, they are voluntary actions that provide important public benefits, such as significantly improving public safety, advancing energy conservation, and promoting the more efficient use of energy, including encouraging combined heat and power installations in the Commonwealth. Another example of the Company's voluntary effort to improve is its adoption of UNITE. UGI Gas's extensive UNITE initiatives, which are designed to provide the Company's employees with the advanced tools needed to support key customer service and operational initiatives and enhance future performance, cannot reasonably be considered the minimum actions necessary to meet the standards of 66 Pa. C.S. § 1501.

Q. Do you agree with the suggestion that the Company's programs are merely meeting its bare minimum obligations under the Public Utility Code?

A. No, I do not. There is ample evidence that the Company is constantly exploring and implementing innovative solutions to improve safety, benefit customers, and support the goals of the Commission and the Commonwealth. For instance, UGI Gas has recently been actively engaged in developing the Renewable Natural Gas ("RNG") market in Pennsylvania. This market offers significant local environmental and economic benefits, as well as increases the sources of supply available on the UGI Gas system and thereby increases competition and improves the Company's resiliency. UGI Gas is the first Pennsylvania NGDC that has received Commission approval to incorporate RNG into its supply portfolio, and it is doing so in an innovative way that allows its customers to benefit from this new on-system source of supply while maintaining cost effectiveness. This is just one example of a comprehensive effort by UGI Gas that is not compelled by 66 Pa. C.S. § 1501 but brings many benefits to customers and the Commonwealth. In addition, UGI Gas's implementation of the many enhanced safety initiatives outlined in my direct testimony go far beyond what would reasonably be considered the minimum actions necessary to meet the standards of 66 Pa. C.S. §1501. Moreover, while still pending before the Commission at Docket No. P-2020-3019196, the Company has filed to voluntarily modify the percent-of-income payments under its CAP program to lower levels in an attempt to make natural gas service more affordable to these low-income customers. The Company also worked to incorporate an Emergency Relief Program in its last base rate case which was focused on enhancing customer assistance during the COVID pandemic.

Q. Is there any other critical flaw with OCA's and I&E's contention that the actions you have identified are necessary to meet the standards of 66 Pa. C.S. § 1501?

A. Yes, there is a significant error with I&E's and OCA's characterization of these actions and achievements as being necessary minimums. Most if not all of these are voluntary efforts undertaken by the Company. It is illogical to conclude that a utility such as UGI Gas, which consistently exceeds the required actions as a regulated public utility and has shown a tremendous commitment to embracing voluntary programs that target improvements across the spectrum of its operations, is merely meeting its minimum service requirements in Pennsylvania under 66 Pa. C.S. § 1501.

Q. Do you have any further comments on the claims made by I&E and OCA that the Company has merely shown performance that meets the Company's basic obligations?

A. It is patently illogical that UGI Gas's exceptional customer satisfaction performance, as demonstrated by the J.D. Power awards, shows only minimally acceptable performance pursuant to 66 Pa. C.S. § 1501. The Company has been recognized for many years as a leader in customer satisfaction amongst its peers. That, by definition, is an indication of performance that vastly exceeds the minimum threshold claimed by I&E and OCA.

Moreover, I&E does not believe that UGI Gas should be entitled to any management performance adder related to its diversity and inclusion efforts, which extend beyond hiring practices and vendor procurement (*i.e.*, policies set forth in 52 Pa. Code § 69.803), or even be permitted to recover some costs associated with those efforts. My direct testimony detailed these efforts, including the Company's Belonging, Inclusion, Diversity, and Equity ("BIDE") initiative, Black Organization Leadership and Development ("BOLD") group, Women's Impact Network ("WIN") and the Veteran Employee Team ("VET"). None of these initiatives are required by Commission regulation, and they create a positive working environment for all individuals. Additionally, UGI Gas's management performance initiatives that extend beyond regulatory obligations include the Company's environmental stewardship, sustainability, and community engagement commitments detailed on pages 32-35 of my direct testimony.

Q. Do you have any final thoughts on the operation of Section 523 of the Public Utility Code?

A. Yes. The provisions of 66 Pa. C.S. § 523 provide the Commission with an important tool to incent utilities to achieve enhanced levels of performance and to implement voluntary programs needed to both provide important benefits to customers and advance important public policy goals. In my view, it is critically important for the Commission to carefully consider and reward superior performance to encourage and maintain high levels of performance to the benefit of ratepayers and the Commonwealth as a whole. As I have demonstrated, UGI Gas certainly meets the required standard.

V. <u>AVERAGE BILL COMPARISON</u>

Q. In his direct testimony, does I&E witness Ethan H. Cline criticize the Company's average bill impact analysis associated with the proposed rate increase?

A. Yes. Mr. Cline takes issue with my testimony wherein I stated that this case will produce lower average customer bills than those paid by customers in 2008. (*See* UGI Gas St. No. 1 at 7.) According to Mr. Cline, the reason why UGI Gas claims that the average bill impact, under the currently proposed rate increase, is lower than the average bills from 2008 is that UGI Gas is including purchased gas costs ("PGC") in its analysis. (I&E St. No. 4 at 24). It is Mr. Cline's position that the PGC costs were higher in 2008 than they are currently and UGI Gas has no control over PGC costs and therefore cannot take credit for the cost difference due to lower PGC costs. Mr. Cline also states that PGC costs do not change because of a rate case. (*Id*. at 24-25.)

Q. Why is the total average bill a relevant metric for consideration?

A. The analysis performed was a bill comparison focused on customer affordability. From a customer affordability perspective, it is not logical to do a partial bill comparison because that is not how customers experience a gas bill. The Company's comparison of historic total customer bills provides a data point showing that the customer's bill as a result of this case will still be within the range of their historic experience.

Q. Do you agree with Mr. Cline's statement that UGI Gas has no control over the gas costs paid by UGI Gas customers?

A. No, I do not. As explained in the Company's annual 1307(f) PGC cases, the Company implements a procurement policy designed to procure natural gas and capacity at the least-cost for PGC customers and to promote price stability. UGI Gas utilizes a supply optimization model and a load duration analysis to plan and manage natural gas demand and supply balances, and uses hedging tools to reduce price volatility to its customers. UGI Gas also considers bidding on released capacity or releasing its own capacity when doing so aligns with its procurement needs and provides economic benefits to its customers. Additionally, the Company flows credits to its PGC customers from short-term off-system capacity releases, storage asset management agreements, and off-system sales pursuant to a revenue sharing mechanism in the Company's Gas Service Tariff. These measures demonstrate that UGI Gas undertakes extensive activities to ensure the lowest possible gas prices for its customers while being positioned to meet peak winter day demand.

Q. Are there any other items in Mr. Cline's testimony that you would like to address?

A. Yes, Mr. Cline identified that I had inadvertently excluded National Fuel Gas Distribution Corporation ("National Fuel") from the average bill comparison chart included in my direct testimony. I agree with Mr. Cline that if the Company performs a comparison to other Pennsylvania NGDCs' average bills in the future, it should include National Fuel. However, this oversight does not substantially change the analysis that UGI Gas's projected average bill is comparable to our peer companies in Pennsylvania.

VI. NRG ISSUES

A. STANDARDS OF CONDUCT

Q. Do you have any initial comments regarding Mr. Reyes's testimony on the Standards of Conduct?

A. Yes, I do. UGI Gas is committed to its compliance with the Commission's Standards of Conduct at 52 Pa. Code § 62.142, and the Company shows that commitment through annual training, internal audits, regular meetings, and process reviews by senior management and Company executives that I will describe in greater detail in this section of my testimony. Further, Mr. Reyes does not make any specific fact-based allegations in his testimony that relate to the Standards of Conduct. He only offers speculation. UGI Gas is fully compliant with the Standards of Conduct and is already subject to the audit authority of the Commission. There is simply no action required by the Commission as a result of Mr. Reyes's testimony.

Q. On pages 5-6 of his testimony, NRG witness Reyes expresses that he is concerned about UGI Gas's compliance with the Standards of Conduct related to employees who have switched positions between UGI Gas and UGI Energy Services, Inc. ("UGIES"). What is your response?

A. Mr. Reyes's concerns are unfounded. UGI Corp. prepares and provides extensive training regarding the importance of adhering to the Standards of Conduct when interacting with all market participants, including affiliates and employees of affiliates. This training ensures that employees understand the legal requirements and that no sharing of prohibited information occurs.

Q. On pages 8-9 of his testimony, Mr. Reyes states that UGI did not indicate how frequently its training materials are provided to employees or whether UGI Gas audits the practices of employees to ensure compliance. What is your response?

A. UGI Gas conducts annual training of its employees on the Standards of Conduct. This training is mandatory for employees that may engage with suppliers, undertake market activities, or have access to competitively sensitive data. UGI Gas monitors employee participation in this training to ensure that all such Company employees are trained on the Standards of Conduct. For employees to be considered trained, they must pass a test related to the training every year.

Q. On page 5 of his direct testimony, Mr. Reyes states that he has "personally observed employees migrating back and forth between UGI and UGIES." Do you wish to comment?

A. Yes. UGI Gas and UGIES do not share any employees as defined in 52 Pa. Code § 62.142(a)(13). However, when UGI Gas employees perform general administration or support services to UGIES, the costs are allocated in accordance with Commission approved affiliate interest agreements and a cost allocation manual (in accordance with 52 Pa. Code § 62.142(a)(9)). While Mr. Reyes did not identify any specific employees which he claimed were shared in his testimony, in discovery he did identify three management employees from UGIES that were previously UGI Gas employees. These three individuals have extensive training and experience relating to the Commission's Standards of Conduct and are trained every year. Moreover, UGI Corp. and its subsidiaries use an open, public, and competitive hiring process. The fact that there are employment applications from affiliate employees is not surprising, given the geographic limitations for many of the positions for which these entities are hiring. As long as employees are thoroughly trained in the Standards of Conduct and those Standards are followed, nothing prohibits an employee leaving UGI Gas to work for UGIES or vice versa. In fact, over the last three years, UGI Gas only had a total of 13 employees leave UGI Gas to take positions with UGIES, out of a total of approximately 1,700 employees of UGI Gas.

Q. Mr. Reyes recommends that the Commission direct UGI Gas to provide a full accounting to the Bureau of Technical Utility Services, within 60 days of a final order in this proceeding, of all employees, along with their titles and job descriptions, who migrate back and forth between UGI Gas and UGIES, along with documentation of how their salaries are allocated. Do you agree with his recommendation?

A. No, I do not. As I mentioned previously, the Company maintains adequate training and controls in place to assure compliance. Further, there is no allocation of salaries between the two companies. The only allocations associated with UGI Gas and UGIES are those related to services provided by UGI Corp. to its subsidiaries, or other costs that are allocated after the specific review by and approval of affiliate interest agreements by the Commission, in accordance with the Public Utility Code.

Q. Mr. Reyes recommends that the Commission direct the Bureau of Audits to examine UGI Gas's compliance with cost allocation, accounting, and record keeping requirements relating to UGIES. Do you agree?

A. No, I do not agree with Mr. Reyes's recommendation. UGI Gas fully complies with all cost allocation, accounting, and record-keeping requirements, and is subject to regular audits by the Bureau of Audits that, among other things, address affiliate relations and cost allocations. Specifically, in its most recent Focused Management and Operations Audit issued in October 2019, the Bureau of Audits made five findings and recommendations in these areas to improve the Company's tracking of affiliate costs and timekeeping for services rendered to affiliates. In its Implementation Plan, the Company accepted all but one of the recommendations and findings (the exception being related to updating affiliate interest agreements) and put into place a timetable for accomplishing those goals. In connection with the audit, UGI Gas submits annual status update reports and has indicated in those reports that it fully implemented the Bureau of Audits' recommendations that the Company had accepted. The most recent of these annual reports was filed with the Commission on December 15, 2021. Regarding the one finding the Company rejected related to updating its affiliate interest agreements, the Company noted that it had recently received re-approval of those agreements in its merger proceeding at Docket No. A-2018-3000381, which was approved one year earlier.

Q. Mr. Reyes recommends that the Commission direct UGI Gas to periodically conduct an internal audit that is designed to review compliance with the Standards of Conduct and report to the Office of Competitive Market Oversight ("OCMO") on a quarterly basis all measures it has taken and how it has handled any departures from the requirements. What is your response?

A. I do not agree with Mr. Reyes's recommendation. In addition to the periodic audits from federal and state regulators that UGI Gas is subject to, the Company has conducted an internal audit of its practices to ensure compliance with the Standards of Conduct and continues to monitor its operations for any issues or practices that may need to be modified in order to avoid a reportable incident. The Company also has robust internal training and encourages employees to use a variety of internal reporting resources, including an anonymous ethics hotline, if they identify any possible violations or reportable incidents. To the extent a reportable incident is discovered as part of its internal process, UGI Gas would certainly take any and all steps required to ensure that it complies with state and federal regulations. Again, this proposal by Mr. Reyes would utilize limited Company and OCMO resources where there is no evidence that these actions are needed, especially since the Company already has adequate practices and controls in place to monitor compliance.

Q. Do you have anything else you wish to add regarding the recommendations of Mr. Reyes on the Standards of Conduct?

A. Yes, I do. In his testimony, Mr. Reyes raises the specter of very serious allegations regarding UGI Gas's compliance with the Standards of Conduct but provides not one single piece of evidence to support his assertions. To the extent that Mr. Reyes believes there is a violation of the Standards of Conduct, the Commission's regulations provide him with the dispute resolution process set forth in 62 Pa. Code § 62.142(b). This procedure provides for a dispute resolution process that requires the natural gas supplier ("NGS") to inform the Company of its concerns so that they can be resolved between the parties without Commission intervention. If the parties are unable to resolve the dispute, the matter is referred to the Office of Administrative Law Judge for mediation, and then, if those efforts are unsuccessful, the affected party may file a formal complaint with the Commission. As UGI Gas has received no formal notice from NRG pursuant to 62 Pa. Code § 62.142(b), which would begin the dispute resolution process established by the Commission's regulations, NRG should not be permitted to disrupt this base rate proceeding with unfounded allegations concerning UGI Gas's behavior with its affiliate.

B. AUBURN GATHERING STATION

Q. On page 10 of his testimony, Mr. Reyes states that he is concerned about UGIES undertaking "risk-free" projects to acquire assets and then selling them to UGI Gas because several of UGI Gas's recent supply expansion activities, including the Auburn Gathering System, have been met by UGIES. How do you respond?

A. Mr. Reyes is mistaken about the nature of the Auburn transaction. Specifically, UGI Gas pursued the Auburn lease at the behest of a customer that requested the ability to expand its supply options to include Tennessee Gas Pipeline Company. To provide the service requested by the customer, UGI Gas needed to lease capacity on the Auburn pipeline. The cost of this transaction is entirely assigned to the customer. Further, UGI Gas fully explained and disclosed the nature of this project in its filing at Docket No. G-2021-3028753, which was approved by the Commission on November 22, 2021.

Q. On pages 10-11 of this testimony, Mr. Reyes suggests that there are instances where information concerning the capability of UGI Gas's system is only known to UGI and UGIES. He specifically points to capacity related to Sunbury as an example of this. What is your response?

A. As the Company stated in its 2019 Gas Base Rate case at Docket No. R-2018-3006814, where the issue of delivery rules on Sunbury was raised by certain suppliers, Sunbury was a publicly noticed open season that was certificated by the Federal Energy Regulatory Commission ("FERC") at Docket No. CP15-525. The subsequent rules relating to delivery on Sunbury were developed through a collaborative process that determined delivery requirements and acceptable substitutes based on the hydraulic and supply characteristics of each geographic segment of the UGI Gas system. The entirety of this process was transparent and prioritized the interests of the Company's customers, by increasing their sources of supply and ability to purchase from a wider variety of supply sources to enhance the competitive marketplace. As was the situation in the 2019 Gas Base Rate case, there is no basis here for claiming that the delivery rules and capacity on the Sunbury system were the product of anything other than a logical application of hydraulic modeling and delivery needs for the UGI Gas system.

Q. Mr. Reyes recommends that the Commission should direct UGI Gas to provide information to NGSs that outlines the full capabilities of its delivery system. (NRG St. No. 1 at 3.) What is your response?

A. The Commission does not need to make such a directive, because UGI Gas readily offers the information NRG is seeking to suppliers on its system. All of the available interconnections on the UGI Gas system for suppliers are identified on the Company's Energy Management Website ("EMW"). In addition, system flexibility is offered to suppliers in the form of ranges for delivery points, by UGI delivery region for suppliers to deliver to certain customer pools. UGI Gas has regularly scheduled supplier collaboratives to review its system demands, address any new or changed circumstances, and provide suppliers with an opportunity to ask the Company questions or seek additional information or insight into the Company's distribution system and delivery regions. These meetings provide suppliers ample opportunity to request, or inquire about, the information Mr. Reyes seeks. As a result, Mr. Reyes's recommendation on this point is unnecessary. UGI Gas has provided delivery rule information consistently to all suppliers and will continue to do so through its EMW, supplier collaboratives, and other means as necessary.

C. AUTOMATION OF SUPPLIERS NOTIFICATIONS

Q. On pages 11-12 of his testimony, Mr. Reyes states that NRG is experiencing ongoing operational issues regarding lack of timely notifications of utility cuts, which occur when a nomination made by an NGS needs to be corrected over the weekend. What is a "utility cut"?

A. UGI Gas is not familiar with this term. However, according to Mr. Reyes, a "utility cut" is "a mismatch in nominated supply between the interstate pipeline and the receiving utility resulting in a failure to meet the required obligation to the utility." (*See* UGI Gas Exhibit CRB-1R.) According to Mr. Reyes a "utility cut" can be initiated by either an interstate pipeline or a utility where supplier nominations do not match interstate delivery information.

Q. Do you agree with Mr. Reyes that these events pose a problem on the UGI Gas system?

A. No, I do not agree. Mr. Reyes provides no evidence regarding the specific operational issues he claims that NRG is experiencing, and he cannot itemize the dates or frequency with which NRG has experienced this issue on UGI Gas's system or the magnitude of the impact in either volumes or dollars to NRG. (*See* UGI Gas Exhibit CRB- 1R.) I am also personally unaware of any instances where UGI Gas has cut supply over a weekend due to a mismatch between nominations provided by a natural gas supplier, like NRG. Further, UGI Gas is not aware of any other suppliers who have concerns similar to those raised by the testimony of Mr. Reyes.

Q. Mr. Reyes recommends that UGI Gas be directed to implement automated programming for these notifications or implement weekend staffing. Do you agree?

A. No, I do not agree. First, I am not sure if automated programming can be reasonably accomplished to compare and analyze supplier nominations on the UGI Gas EMW and the various interstate pipelines and interconnects that provide service to UGI Gas. Mr. Reyes proposes a solution that, if workable, would likely have a very significant operational cost to UGI Gas without evidence that there is an issue to address. Further, I do not believe that UGI Gas should be the party responsible for finding a solution to Mr. Reyes's concerns, if there is such a problem to be solved. Based on a review of the discovery responses provided by NRG on this topic, the primary issue appears to be related to a lack of communication between NRG and its third-party suppliers over weekends. UGI Gas is not a party to those transactions. Finally, NRG fails to show that the issue represents a significant problem that threatens the Company's ability to provide service to customers or has widespread impacts that harm the competitive market. Without such evidence, the Commission should not direct UGI Gas to implement a likely expensive solution to an unproven problem with unknown benefits.

Q. Do you have any other comments relating to this topic?

A. Yes, I do. Based on Mr. Reyes's definition, a "utility cut" may include a mismatch between a supplier's submitted volumes and the pipeline nominations identified on the Electronic Bulletin Board. As a courtesy to suppliers, UGI Gas regularly reviews nominations to help ensure that entries submitted by suppliers align with pipeline nominations, and the Company identifies obvious data entry errors that could potentially subject a supplier to a nomination mismatch. To provide this feedback to suppliers for their weekend nominations, the deadline for Saturday, Sunday, and Monday nominations is on Friday at 2:00 p.m. A review of the Company's records indicates that NRG regularly fails to meet this deadline for its Sunday and Monday nominations. As a result, UGI Gas employees do not have sufficient time during normal business hours to review NRG nominations for Sunday and Monday and provide courtesy notice of errors by NRG or their third party suppliers. Prior to asking the Commission to direct UGI Gas to undertake a likely expensive solution to a problem that may exist only for NRG, NRG should first show that it is in compliance with the weekend nomination deadlines.

D. WEIGHTED AVERAGE COST OF DELIVERED GAS

Q. On pages 13-14 of his testimony, Mr. Reyes states the Weighted Average Cost of Delivered Gas ("WACOD") does not show the individual impacts of a specific rate case. How do you respond?

A. Mr. Reyes' claim is somewhat misleading. The Company does identify when FERC rate changes, including the impacts of Natural Gas Act Section 4 rate proceedings, are first included in the WACOD. The Company also identifies when any adjustments are made to reflect the final rates, as well as refunds associated with final rates that are lower than the filed rates charged during the interim period. While the Company does not separately itemize FERC rate impacts in the overall calculation of the WACOD or show an individual Section 4 proceeding's particular impact on a monthly basis over time (as Mr. Reyes's testimony suggests), this is because the WACOD calculation includes many moving parts, and teasing out the effects of a single FERC proceeding would require the Company to keep and update numerous individual WACOD files that would contain no longer valid or applicable pipeline rates, and calculate the WACOD to track each separate component of data.

Q. Mr. Reyes recommends that UGI Gas be required to include more detailed information concerning the effect of pipeline rate changes on its Electronic Bulletin Board or through other means, including providing the information by electronic mail to suppliers. (NRG St. No. 1 at 15.) Do you agree?

A. No. NRG is a sophisticated entity, and Mr. Reyes admits that NRG monitors and participates in FERC proceedings on behalf of its customers. (*See* UGI Gas Exhibit CRB-2R.) As a result, NRG should be fully capable of assessing, with a reasonable degree of certainty, the impacts of various FERC proceedings on its cost of transportation service it relies upon in serving its customers. Further, the process currently utilized by UGI Gas is applied consistently to all impacted customers and suppliers, and therefore does not have a discriminatory impact on NRG as compared to other suppliers.

Q. Mr. Reyes also recommends that the Economic Benefit of Peaking Service ("EBPS") and LFD gross up be removed from the LFD WACOD rates. (NRG St. No. 1 at 15-16). Do you agree?

A. No, I do not. The WACOD is a mechanism that is intended to fully reflect the costs of providing the transportation program to the customers who utilize it. Therefore, the EBPS and LFD costs are appropriately incorporated into the WACOD. While Mr. Reyes proposes that UGI Gas direct bill these charges to shopping customers, any modifications, and specifically any efforts to separately identify on customer bills the costs of or credits associated with the transportation service offered by the Company, will cause the Company to incur additional and unnecessary programming costs to change the bill format in order to accommodate new information.

VII. <u>HEAT CONTENT ADJUSTMENT PROGRAMMING COSTS</u>

Q. Please describe the Company's heat content adjustment factor.

A. On May 26, 2021, UGI Gas filed a tariff supplement at Docket No. R-2021-3026078 seeking to add a heat content adjustment factor to customer bills. This adjustment factor ensures that the inclusion of gas with a lower British Thermal Unit ("BTU") content on the UGI Gas system does not adversely impact UGI Gas customers when such gas is metered on a volumetric (per CCF or MCF) basis. This adjustment factor was made necessary by the anticipated impacts of RNG that has been and will be added to the UGI Gas system in coming years. The heat content adjustment factor recognizes that RNG that enters the UGI Gas system will have a heat content, measured in British Thermal Units ("BTU"), around 970 BTUs. This heat content is at the lower end of the allowable heat content identified in the Company's gas quality specifications. Without the heat content adjustment factor, customers receiving significant amounts of RNG will require a greater volume of gas to achieve the same heating output as traditionally sourced gas (e.g., from interstate pipelines), which would result in higher metered volumes and higher bills. The Commission approved the heat content adjustment factor tariff supplement on August 5, 2021.

Q. What concern did OSBA raise in regard to the Company's heat content adjustment factor?

A. Mr. Knecht identifies that OSBA intends to contest the budgeted cost for information system rate base associated with the heat content adjustment factor. (OSBA St. No. 1 at 25.)

Q. What costs were associated with the project identified by Mr. Knecht.

A. The Company identified $2.0 million in costs, which were the budgeted itemized internal costs associated with necessary programming to reconfigure the Company's billing system to calculate the heat content adjustment factor and apply it to customer bills.

Q. **Do you believe that these costs should be disallowed?**

A. No, I do not. At a minimum, I believe that Mr. Knecht would agree that: (1) the heat content adjustment factor is the appropriate response to the presence of lower BTU gas on the UGI Gas system; and (2) the failure to implement such an adjustment factor could cause economic harm to customers receiving significant quantities of lower BTU gas.

Q. How are IT projects like the heat content adjustment programming costs budgeted?

A. These costs were incurred by Company employees undertaking standard tasks associated with their employment. Specifically, IT projects are given individual budgets and then are tracked internally on a project basis. However, as the resources being used to accomplish many of these projects are internal full-time IT employees, any hours that were budgeted for a particular project but ultimately not needed are reallocated to other necessary IT projects. And that, indeed, is exactly what happened with regard to the heat content adjustment factor IT project. The $2 million identified by Mr. Knecht reflects the total budget for the three phases of the project. The first phase of the project came in significantly under its anticipated budget and ahead of schedule, and ultimately only used $662,319 of internal IT resources and no external resources, rather than the originally budgeted $1,101,182. As a result, the remaining project budget for phase one was allocated to other IT projects that could be addressed once the resources allocated to the heat content adjustment factor became available. The second and third phases of this project, which allow for a system-wide rollout of the adjustment factor and optimization of the functionality to wrap up the project, are similarly anticipated to be under budget, with any remaining budget then going to other IT projects that were identified and put in the queue after the heat content adjustment factor. The IT costs identified for the heat content adjustment factor are appropriately included in the Company's overall claim, as they are a necessary measure to protect customers from any disproportionate impact that may occur from the changing supply resources on the UGI Gas system and fully utilize internal Company resources.

VIII. ISSUES IMPACTING COMPETITIVE CUSTOMERS

A. CAPACITY ASSIGNMENT

Q. OCA witness Mierzwa disagrees with the Company's proposal to continue existing procedures for capacity releases to Rate XD customers in the former UGI South Rate District. (OCA St. No. 3, at 42-43.) Why does he oppose the existing capacity assignment procedures for capacity releases to Rate XD customers?

A. Currently, in the former UGI South Rate District, "Rate XD customers are assigned Columbia Gas Transmission ("TCO") firm transportation ("FT") pipeline capacity and are assessed the same rates UGI Gas is charged for that capacity by TCO." (OCA St. No. 3 at 43.) According to Mr. Mierzwa, this existing procedure is unreasonable because "TCO capacity released to Rate XD customers in the former South District is among the Company's lowest cost capacity resources," and Rate XD customers should not have preferential access to the Company's lowest cost capacity resources while PGC and Choice transportation customers are held responsible for the costs associated with the Company's higher cost capacity resources." (OCA St. No. 3 at 43.)

Q. What is Mr. Mierzwa's recommendation?

A. He recommends that "Rate XD customers…continue to be assigned TCO capacity until their current service contracts expire, at which time Rate XD customers should be assessed the same charges for released capacity that are assessed to Rate LFD customers." (OCA St. No. 3 at 43.)

Q. Do you agree with this recommendation?

A. No. I disagree with Mr. Mierzwa's recommendation. The cost of UGI Gas's interstate pipeline capacity, including on TCO, has been increasing due to recent Section 4 proceedings at FERC. Further increasing capacity charges for Rate XD customers that have historically received TCO capacity (all of whom have competitive alternatives) may result in these customers terminating service from UGI Gas or, perhaps more likely, demanding a reduction to the base distribution charges they currently pay.

Q. Please provide a brief history of the Company's capacity release program and describe how the Company determines which capacity is to be used in calculating the rates for large transportation customers.

A. The Company's current capacity release program dates from before the settlement of the Company's 1995 base rate proceeding at Docket No. R-00953297 ("1995 Settlement"), which was approved by Commission Order entered August 21, 1995 ("1995 Order"). Pursuant to the 1995 Settlement, the Company was permitted to continue assigning Rate XD customers up to 50,241 Dth of Columbia/Columbia Gulf Capacity and provide a credit to the PGC for the cost of that capacity. *See* 1995 Order ¶ 18. The 1995 Settlement provided that for capacity released to Rate LFD customers, the PGC would be credited an amount equal to the quantity of firm capacity provided to Rate LFD customers multiplied by the weighted average cost of firm transportation on all pipelines serving the Company, exclusive of capacity assigned to Rate XD customers. *See* 1995 Order ¶ 20. The capacity charges for Rate XD and LFD customers, at that time, did not include the cost of storage capacity or peaking capacity. Subsequently, the capacity charges were incorporated into the Company's tariff and its service agreements with large transportation customers. The 1995 Settlement precluded any challenge to the capacity charges for Rate XD and LFD customers until the next base rate proceeding.

In the Company's 2016 base rate proceeding at Docket No. R-2015-2518438, the capacity release program was again proposed, unchanged from the one approved in the 1995 Settlement, and no party challenged the program in testimony. The Commission-approved settlement ("2016 Settlement") provided that, unless specifically enumerated, the Company's tariff filing was approved as proposed. 2016 Settlement ¶ 16. Currently, nearly all of the 50,241 Dth of Columbia capacity has been subscribed to, and no new Rate XD customers are eligible for a release of this capacity at Columbia maximum tariff rates without an existing customer lowering its election to make the capacity available.[3] Current and new Rate LFD customers may elect to receive a capacity release of firm transportation capacity from the Company based on the capacity charge formula agreed to in the 1995 and 2016 base rate proceedings. For Rate XD customers, this methodology has remained unchanged for more than 25 years and its continuation has been relied upon by both the XD customers and the Company alike for contract renegotiation purposes and supply sourcing as well.

Q. Do you agree with Mr. Mierzwa's recommendation to charge Rate XD customers the cost of WACOD plus 50% of peaking demand charges upon the expiration of their service agreements?

A. No. Rate XD customers are considered competitive customers due to their access to alternative fuel sources or their ability to bypass utility service and connect directly to an

[3] Because of the fluctuating thermal to volumetric conversion between Dekatherms and million cubic feet, the Columbia capacity is not fully subscribed; however, there is insufficient capacity to subscribe additional XD customers.

interstate pipeline or their ability to move operations to other facilities located outside the UGI Gas service territory. For this reason, they pay negotiated rates. Any increase in costs to these customers increases the likelihood that they will leave utility service, or conversely will have an offsetting decrease in their negotiated distribution rate due to the increase in their pipeline capacity rate. If a significant number of large transportation customers stopped taking distribution service from the utility, the Company could be required to seek base rate relief based on lost revenues from these very large customers, thus resulting in increased distribution rates to the remaining customers. Additionally, these XD customers employ thousands of people who also live within the Company's service territory. Many of these employees are UGI Gas customers themselves (at their primary residence), so to the extent that these XD customers may move their business operations to other locations outside the UGI Gas service territory (due to higher energy costs as proposed by Mr. Mierzwa), there could be additional economic implications to UGI Gas's customer base and anticipated future revenue streams beyond the potential loss of XD customer revenue. Accordingly, Mr. Mierzwa's proposal should not be adopted.

B. RATE INCREASE ALLOCATION TO RATE CLASSES XD AND IS

Q. In addition to Mr. Mierzwa's proposal, where there any other positions advanced that would impact competitively situated customers?

A. Yes, OSBA witness Knecht proposes to move $2 million of the proposed rate increase for Rate N/NT to the Rate XD and Rate IS customer groups.

Q. Do you agree with this adjustment?

A. No, I do not agree with this adjustment. Mr. Knecht correctly notes that the dollars he has identified as rate reductions reflected by the Company for Rates XD and IS merely reflect the reset of the DSIC rate back to zero. (OSBA St. No. 1 at 15). Mr. Knecht also acknowledges that these customers are paying negotiated rates. (*Id.*) Finally, Mr. Knecht acknowledges that these customers are paying significantly above the system average under current rates. (OSBA St. No. 1, Table RDK-4). Mr. Knecht's own facts do not support his proposed allocation.

Q. Why should Mr. Knecht's proposed adjustment to Rates XD and IS be rejected?

A. The customers paying Rates XD and IS are competitively situated customers with negotiated rates, as I described in the prior section of my testimony regarding capacity assignments. This means they have options that could either allow them to bypass the UGI Gas system or they may move their operations outside the Company's service territory and, overall, are very sensitive to contract terms. The fact that these customers have negotiated contracts limits the Company's ability to increase their rates between negotiation periods. Said differently, Mr. Knecht's proposal could not be translated into costs borne by the customers in the customer class he has identified, because the majority of the customers in these two rate classes will not have contracts that are renegotiated in the FPFTY as many are under multi-year contract terms.

Q. Why is it inappropriate to impute the reduction associated with the DSIC onto the base contract rates paid by Rate XD and IS?

A. The Commission has recognized that for competitively situated customers, such as the Rate XD and IS customers, the Company may not be able to apply the DSIC charge.

Specifically, the Commission stated in *Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Distribution System Improvement Charge*, Docket P-2012-2338282, p. 57 (Order entered May 22, 2014):

> In our *Final Implementation Order*, we stated that "utilities should have the flexibility to *not* apply the DSIC surcharge to customers with competitive alternatives and customers having negotiated contracts from the utility." *Final Implementation Order* at 46 (emphasis in original). We also acknowledged the reality of a public utility's contractual relationship with competitive customers in stating that, "[w]here the customer negotiated rates based on competitive alternatives, it would be contrary to the contract terms and counterproductive in the long term to add costs that may induce the customer to leave the system and provide no support for infrastructure costs." We then indicated that, accordingly, the DSIC "need not be applied" to competitive customers. *Final Implementation Order* at 46. As such, our Order provided public utilities, like Columbia, with the discretion to not apply the DSIC to competitive customers.

The Commission referenced the Columbia Order in making a similar determination that UGI Gas may reduce or eliminate the DSIC for competitively situated customers. Despite this language, UGI Gas has successfully negotiated for some customers on Rates XD and IS to pay the DSIC. and the benefit of that goes directly to other customer classes given the reconciling nature of the DSIC. The Company will collect approximately $2 million of DSIC contribution from competitively situated customers in the FTY. Contributions by Rate XD and IS customers to DSIC revenue requirement amounts result in overall lower amounts needing to be collected from all other customers.

Q. In its negotiations with competitively situated customers, does the Company account for the general upward trend in rates?

A. Yes. Given today's high prices for alternate fuels, for many of these customers, when contracts are renegotiated, UGI Gas must look to price the contract based on the customer's other firm rate alternatives, such as Rate LFD. Thus, when Rate LFD moves up due to the impacts of a rate case, future contract negotiations are often subject to the same upward pressure. In this way, while Rate XD and IS are not directly impacted by rate cases, the contracts do ultimately reflect the same considerations raised by OSBA in this proceeding. This includes the Company's efforts to apply the DSIC to more competitively situated customers. A wholesale update to negotiated contracts in order to update rates to reflect a DSIC roll-in, as Mr. Knecht advocates, will spotlight the "renegotiation" of these contracts with this competitive group and lead to: (a) some customers looking to renegotiate base contract rates mid-term for competitive cost changes on their side; (b) a much larger number of these customers needing to be exempt from DSIC charges altogether under the allowed competitive exclusion provisions of the DSIC; and (c) a reduced ability to finesse the rate negotiations which serve to maximize the revenue contributions these customers make to the system, to the benefit of all customers. In total, there would be significant risk that revenues would actually be lower from Rate XD and Rate IS customers as a result of adopting Mr. Knecht's recommendation.

Q. Does the Company have any other demonstration on how it has been able to maximize the revenues from these competitively negotiated Rate XD and IS contracts, which then benefit all other customers?

A. Yes. As shown below, in review of data from the Company's base rate case filings in 2019, 2020 and now 2022, the Company has been able to consistently increase Rate XD and Rate IS revenues over the past several years. See the respective UGI Gas Exhibit E – Proof of Revenue from each filing. The following table shows the total combined revenue contributions from these two customer classes in each of the last three rate cases:

Table 1:

	Revenues from Rates XD and IS
2019	$48,404,813
2020	$53,298,458
2022	$60,710,158

Table 1 demonstrates the Company's successful efforts, which serve to otherwise lower the revenue contribution required from all other customer rate classes.

IX. _*PRO SE*_ <u>COMPLAINANTS AND PUBLIC INPUT HEARINGS</u>

Q. Were there public input hearings conducted in this proceeding?

A. Yes. On April 13, 2022, the Company participated in two telephonic public input hearings, which were publicly noticed and conducted by the presiding Office of Administrative Law Judges at 1:00 pm and 6:00 pm. In total, six individuals testified on the record during the 1:00 pm session, and three individuals testified on the record during the 6:00 pm session.

Q. Did any current Company employees participate in the public input hearings?

A. Yes. William Corcoran, a UGI Gas field worker, testified on behalf of the International Brotherhood of Electrical Workers ("IBEW") Local 1602 in Lancaster, Pennsylvania during the 1:00 pm session. Also, Christopher Cortright, a warehouse employee of the UGI Lehigh Valley office, testified on behalf of IBEW Local 1456 during the 6:00 pm session.

Q. What questions did Mr. Corcoran raise during the public input hearing?

A. Initially, Mr. Corcoran asked how UGI Gas's proposed revenue increase in this proceeding will help the Company earn a fair rate of return on investments. He also wanted to understand what investments were involved. (Transcript for 1:00 pm Session at 27-28.)

Q. Can you respond to Mr. Corcoran's questions?

A. Yes. The Company's case includes an adjustment for the rate of return ("ROR"), which is applied to the overall calculation of base rates. As detailed in the direct testimony of UGI Gas witness Paul R. Moul (UGI Gas St. No. 6), the Company needs to earn a ROR that covers the Company's interest and dividend payments to investors who have equity in the Company. The ROR also needs to allow the Company to attract new shareholder investments by compensating these investors for the risk undertaken when investing in UGI Gas. These shareholder investments allow the Company to raise the capital needed to install and replace components of its natural gas distribution system, as well as other capital investments, thereby maintaining safe and reliable service to customers.

Q. What training concerns did Messrs. Corcoran and Cortright raise during the public input hearing?

A. Mr. Corcoran stated that UGI Gas's infrastructure replacement programs should only be performed by UGI Gas employees. (Transcript for 1:00 pm Session at 28-29.) Mr. Cortright expressed a desire for comprehensive curriculum training. (Transcript for 6:00 pm Session at 23.)

Q. Please respond to the concerns relating to training.

A. UGI Gas has a rigorous training process focused on safety and requires all employees and contractors to be sufficiently trained. Safety training for employees and contractors is overseen by the UGI Safety and Training group. Safety training is tracked, including training attendance and expiration of operator qualifications ("OQ"). UGI Gas administers the OQ program making sure their employees maintain qualifications specific to their job duties per federal regulations (42 C.F.R. § 192(N)). UGI Gas's Emergency Responders, Duty Supervisors, and Senior Supervisors receive extensive training on many critical field activities on a regular basis. In addition, there is onboarding emergency response training for all field employees. Further, since 2016, the Company has participated in the Northeast Gas Association's Enhanced Operator Qualification Program. The Enhanced OQ Program includes the development of critical thinking skills through its online knowledge training supplemented by the Company's hands-on classroom training for required skills specific to Company procedures. The Company's OQ Program currently includes 138 Covered Tasks, which comply with the requirements set forth in 49 C.F.R. 192, Subpart N.

In addition, the Company's safety training program is being modified to maximize the use of the state-of-the-art training center, which has recently become fully functional for training purposes. This new facility will provide an even better and more hands-on opportunity for field crews to hone their skills and improve their use of safe practices.

Q. What concerns did Mr. Corcoran and Mr. Cortright raise regarding the Company's use of contractors?

A. Mr. Corcoran feels that UGI Gas is using too many contractors to do work that traditionally was performed by Company employees. (Transcript for 1:00 pm Session at 28.) Both Mr. Corcoran and Mr. Cortright expressed concerns that reliance on contractors hinders the ability of UGI Gas employees to learn in the field. (*Id.*; Transcript for 6:00 pm Session at 23.)

Q. Please respond to concerns relating to the use of contractors.

A. The Company uses a mix of contractor and employee resources because the volume of work that is currently being done exceeds UGI Gas's ability to hire and utilize only Company employees. A decade ago, before the Company commenced its accelerated main replacement program, there was less need for supplemental resources. However, to replace 70 miles of aged main per year, as well as meet all of the other standard utility field operations, the Company needed to expand its field crews and do so at a rapid pace. The only way to accomplish that was through the addition of more contractor crews. Further, contractor resources are often a prudent option, since there is some seasonality to the volume of work being done. Contractor numbers can be added during times where there is a larger workload and reduced during slower times of the year. However, employee crews continue to be a vital part of the Company's operations, and the new training center will create a better, safer, and more effective environment to get all field crews the kind of hands-on experience they need to perform optimally in the field.

Q. What concern did Mr. Corcoran raise in regard to the tools and technology that UGI Gas's field workers utilize in the field?

A. Mr. Corcoran claimed that the Company's "in-field technology" is outdated. (Transcript for 1:00 pm Session at 28.)

Q. Please describe the Company's use of new technology.

A. UGI Gas has been very active in working toward upgrading its technology and incorporating new and improved technology, including through its UNITE program efforts. In some instances, the first step to incorporating new technology required the Company to first adopt new computer systems that would be compatible with and provide more functionality for field crews. The UNITE program has focused on making many of these changes over recent years. As a result, field crews have been and will continue to be provided with modern technology that will make them more efficient and improve the Company's record keeping.

Q. Did any current *pro se* complainants participate in the public input hearings?

A. Yes. Two of the *pro se* complainants testified on the record during the hearings: Paula Mercuri and Annette Miraglia. They along with Lisa Musser, Sabatini Monatesti, and Kirsten Andersen, who are UGI Gas customers but did not file complaints against the rate case, testified at the public input hearings about the significance of the increase and how it would affect customers. The Company strives to strike a balance between increasing rates to its customers and undertaking the very costly infrastructure repair and replacement programs, safety initiatives and IT system upgrades that allow it to meet and exceed its obligations under 66 Pa.C.S. § 1501. The Company also has and continues to incorporate a variety of programs targeted at assisting lower income customers in both paying current bills and reducing future bills through conservation efforts.

Q. What testimony was placed on the record regarding the Company's proposed Weather Normalization Adjustment ("WNA")?

A. During the 1:00 pm Session, Mr. Corcoran and Ruth Weaver discussed the WNA proposal. Mr. Corcoran asked that the Company fully explain the mechanism to customers with understandable examples. (Transcript from 1:00 pm Session at 29.) Ms. Weaver expressed concerns that the WNA would increase summer bills. (*Id.* at 46.)

Q. Please respond to the concerns about the WNA.

A. UGI Gas witness John D. Taylor discusses the Company's plans regarding WNA-related customer education/outreach in his rebuttal testimony, UGI Gas St. No. 11-R. Regarding Ms. Weaver's claim, the WNA mechanism applies in the months of October through May. If weather is colder than normal during those months, the Company will issue a bill credit to customers. If weather is warmer than normal during those months, a surcharge will be applied to the bill. The WNA will not impact summer bills unless the customer elects to participate in the Company's budget billing program, in which case any impacts from WNA would be averaged over the 12 monthly bills per year consistent with the rules of the budget billing program.

Q. Please summarize the public input hearing testimony of Eric Epstein.

A. Mr. Epstein claimed that the Company's use of the DSIC and the associated LTIIP initiatives represent poor corporate planning on UGI Gas's behalf. Mr. Epstein appears to believe that the Company should have been replacing its distribution system components prior to when the DSIC was implemented. (Transcript from 6:00 pm Session at 39.) Mr. Epstein also stated that he does not support the rate increase. (*Id.*) He also recommended that the Commission adopt a new method for reviewing rate cases, using what he terms an "aggregate impact statement." (*Id.* at 40.) In other words, the Commission should not review rate increases in isolation. According to Mr. Epstein, the Commission should consider all expenses, including inflation, for all utility customers when approving rates. He also recommended that utility companies be placed on Commission-issued budget plans when they demonstrate poor management performance. (*Id.* at 41.)

Q. Please respond to Mr. Epstein's claims regarding planning.

A. UGI Gas, along with the vast majority of the natural gas and electric utilities in Pennsylvania, is engaged in the accelerated replacement of infrastructure. Providing NGDCs and Electric Distribution Companies ("EDCs") the incentive to undertake these systemwide replacements on an accelerated basis is exactly why Act 11 was adopted and the fundamental reason why the DSIC mechanism was extended to NGDCs and EDCs. Mr. Epstein provides no facts regarding what historical management practices or decisions he believes were poorly implemented.

Q. Please respond to Mr. Epstein's recommendation that no revenue increase be granted.

A. Mr. Epstein's recommendation to deny the Company's revenue increase would significantly hamper the Company's ability to continue replacing infrastructure on an accelerated basis, a result which should be avoided. The replacement of aging main is critical to the continued ability of UGI Gas to provide safe and reliable service to customers.

Q. Do you agree with Mr. Epstein's proposal that the Commission prepare "aggregate impact statements" during utility rate cases?

A. No. First, Mr. Epstein's proposal is not clear on how the Commission would apply his recommendation. Second, this recommendation would be a rejection of the basic and fundamental principles of ratemaking, including the requirement that utilities receive a return of and on plant placed in service for public use. Mr. Epstein's approach would link a utility's ability to recover its costs to the increase in other costs and services, including increases in unregulated costs outside of the Commission's jurisdiction, instead of looking at whether the activities of the utility are just, reasonable, and necessary for service to the public. For customers struggling with affordability, the Company's Universal Service Programs are designed to assist qualifying customers. Mr. Epstein's recommendation should be rejected as it is unlawful.

Q. Please respond to Mr. Epstein's recommendation that the Commission should place public utilities on budget plans if they demonstrate poor management performance.

A. This proposal is fundamentally unnecessary. Rate cases provide the Commission the opportunity to review and approve the details of a utility's rates, including all relevant costs that will be imposed on customers and the performance of management. The Commission, at its discretion, may disallow costs that are not used to serve the public or that were imprudent. Further, through the LTIIP, the Commission has the opportunity to review and approve the major infrastructure activities planned by utilities on both a forward looking and annual basis to ensure that utility resources are being appropriately dispatched. The Commission already has clear legal authority to consider management performance in the establishment of rates, and also has the authority to regularly audit utility operations. As such, this recommendation by Mr. Epstein is unnecessary and should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit CRB-1R

Responses of NRG Energy, Inc. to the Interrogatories of UGI Utilities, Inc. – Gas Division, Set I in Docket No. R-2021-3030218

Request: UGI – NRG I-6: Reference NRG Statement No. 1, page 11, line 21.

a) Please define the term "utility cut."

b) Please identify who initiates the "utility cut".

c) Please explain why the "utility cut" occurs.

d) For the last three years, please identify all instances on the UGI Gas system where NRG has experienced a "utility cut." For each instance identified by NRG, please include the following: date, whether the cut occurred on a weekend, the number of volumes impacted, and any penalties incurred by NRG.

Response:

a) A utility cut is a mismatch in nominated supply between the interstate pipeline and the receiving utility resulting in a failure to meet the required obligation to the utility.

b) A utility cut can be initiated by either the interstate pipeline for various reasons or by a utility if the supplier's nominations do not match the interstate delivery information (contract numbers, volumes, delivery points, etc.).

c) The supply nomination process involves a robust third-party market, with several entities exchanging information outside the control and/or knowledge of the NGS. For example, the Interstate schedulers exchange delivery points and transportation contract numbers. These numbers are passed between parties and there can be instances when a transposition occurs. Additionally, an interstate pipeline may experience constraints or operational issues that result in utility cuts.

d) NRG does not maintain a record of utility cuts by utility. Historically, NRG has worked with the utility and been granted the ability to have retroactive nominations executed to mitigate any potential impacts. The purpose of the retroactive nomination is to eliminate the penalty risk posed by such a reduction that exists under the tariff. If NRG has timely notification of any non-compliance with the required delivery obligation, it has the ability real time to adjust and ensure that it is in a compliance with its delivery obligation. Absent real time notification, NRG is at risk of violating requirements and of being penalized if the utility, interstate pipeline and supplier will not all agree on a retroactive nomination.

UGI maintains a log listing of UGI Utilities Nomination Confirmation Issues, which are sent to suppliers via email to timely identify any nomination issues. Below is a screenshot of the email notifications received by NRG since September of 2021, which do not include a single weekend notification.

Responses of NRG Energy, Inc. to the Interrogatories of UGI Utilities, Inc. – Gas Division, Set I in Docket No. R-2021-3030218

All Unread By From

From	Subject	Received	S	Categories	M..
supplyconfirmations@ugi.com: 25 item(s)					
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000936]	Fri 4/8/2022 2:49 PM	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000935]	Fri 4/8/2022 2:42 PM	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000919]	Tue 4/5/2022 2:11 PM	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000918]	Tue 4/5/2022 2:11 PM	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000904]	Fri 4/1/2022 2:19 PM	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000898]	Wed 3/30/2022 2:2...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000895]	Tue 3/29/2022 2:34 ...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000782]	Tue 2/22/2022 2:09 ...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000719]	Tue 1/25/2022 2:26 ...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000679]	Mon 1/10/2022 2:1...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000662]	Thu 1/6/2022 2:53 PM	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000644]	Mon 1/3/2022 2:10 ...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000627]	Mon 12/20/2021 2:...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000592]	Tue 12/7/2021 2:17 ...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000541]	Mon 11/22/2021 3:...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000447]	Wed 11/3/2021 3:1...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000446]	Wed 11/3/2021 3:1...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000447]	Tue 11/2/2021 2:54 ...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000446]	Tue 11/2/2021 2:50 ...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000399]	Mon 10/18/2021 3:...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000364]	Fri 10/8/2021 2:08 PM	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000348]	Mon 10/4/2021 10:...	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000348]	Fri 10/1/2021 3:11 PM	1		
supplyconfirmations@ugi.com	UGI Utilities Nomination Confirmation Issue [Log #00000338]	Wed 9/29/2021 3:0...	1		
supplyconfirmations@ugi.com	EXT UGI Utilities Nomination Confirmation Issue [Log #00000227]	Thu 9/2/2021 3:07 PM	1		
Surayya Rafi: 5 item(s), 1 unread					

As an example, NRG received a notification on Tuesday, May 18, 2021 of a utility cut made over a weekend. The email chain is included in Attachment 6.

Response provided by: Christopher Reyes

Dated: May 2, 2022

UGI Gas Exhibit CRB-2R

Responses of NRG Energy, Inc. to the Interrogatories of UGI Utilities, Inc. – Gas Division, Set I in Docket No. R-2021-3030218

Request: UGI – NRG I-12: Reference NRG Statement No. 1, page 13, lines 2-3.

a) What impact does an individual pipeline rate case have on NRG or its customers?

b) Does NRG participate in FERC proceedings on behalf of its customers? If so, please describe the nature of the participation.

Response:

a) Please see Mr. Reyes' Direct Testimony at page 14, lines 2-12.

b) Yes. NRG monitors and participates in individual FERC proceedings that impact NRG and its customers. This participation includes attending hearings, reviewing material and participating in settlement negotiations.

Response provided by: Christopher Reyes

Dated: May 2, 2022

CONFIDENTIAL VERSION

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et. al

UGI Utilities, Inc. – Gas Division

Statement No. 2-R

Rebuttal Testimony of
Tracy A. Hazenstab

Topics Addressed:	**Revenue Requirements Updates** **Response To Adjustments To Operating Revenues And Expenses** **Interest Synchronization** **Compliance With PA Act 40 Of 2016**

Dated: May 17, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 2, on January 28, 2022.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony provides updates to certain components of the Company's revenue requirement, based on the information provided during the discovery phase of this proceeding and additional information affecting the Company's cost of serving its customers. In addition, my testimony responds to certain portions of the following direct testimony submitted by the Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"): I&E Statement No. 1, the direct testimony of Zachari Walker; I&E Statement No. 3, the direct testimony of Brain J. LaTorre; and OCA Statement No. 1, the direct testimony of Dante Mugrace.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. As discussed below, I am sponsoring the Company's final accounting exhibit, "UGI Gas Exhibit A - Fully Projected (REBUTTAL)," which reflects all the corrections and updates to the Company's claim to date.

Q. Please provide an overview of the other parties' revenue requirement adjustments.

A. I&E recommended a revenue requirement of $1,094,441,000, which represents an increase of $18,072,000 to I&E's adjusted present rate revenues of $1,076,369,000, which is a decrease of $64,670,000 to UGI Gas's revenue requirement of $82,742,000. I&E St. No. 1 at 3. I&E's recommended revenue requirement includes a net decrease of $4,850,000 to UGI Gas's claimed operating expense (the decrease is the net of non-purchase gas cost expenses less purchased gas cost expense), a total reduction of $835,000 to cash working capital, a total reduction of $137,649,000 to plant in service, a total increase of $14,648,202 to present rate revenue, the use of the capital structure proposed by the Company, and a return on equity of 9.92%.

OCA recommended a revenue requirement decrease of $38,674,000, which is $121,416,000 lower than UGI's proposed revenue requirement increase of $82,742,000. OCA St. No. 1 at 4. OCA's recommended revenue requirement includes a total reduction of $33,940,000 to operating expenses, a total reduction of $81,724,283 to rate base, a hypothetical common equity ratio of 50%, and a return on equity of 8.50%.

Q. Does the Company agree with the distribution revenue requirement proposed by the other parties?

A. No. As explained throughout this testimony and the other rebuttal testimony forming UGI Gas's rebuttal position, with the exception of certain updates to the Company's revised filing and the acceptance of some relatively minor operating expense and rate base adjustments, the Company believes that the various revenue, expense, and rate base adjustments proposed by the opposing parties are not reasonable and therefore should be rejected.

II. <u>UPDATES AND CORRECTIONS TO THE COMPANY'S CLAIM</u>

Q. Since the filing of your direct testimony, has the Company identified any components of its filing that should be updated?

A. Yes, during the discovery phase of this proceeding, the Company identified parts of its initial filing that required revision. These include the following updates, some of which have already been accepted by OCA or I&E in their direct testimony:

- <u>OSHA/Emergency Temporary Standard ("ETS") Compliance Costs</u>: In its response to discovery question OCA-III-25, the Company acknowledged that it is withdrawing the majority of its claim associated with this mandate. Because the Company did incur $52,934 in costs related to legal advice and a subscription to vaccine tracking software, the Company proposes to defer and amortize these costs over a one-year period. This adjustment, in the amount of $1,830,000 is further outlined in the rebuttal testimony of Vivian K. Ressler (UGI Gas Statement No. 3-R). In addition, a revised Schedule D-13 is provided as an exhibit to my rebuttal testimony.

- <u>Depreciation Expense for Enterprise Resource Planning System</u>: The Company identified that its initial claim did not include an adjustment to allocate to its affiliates a portion of depreciation expense on this shared IT asset. This adjustment of $524,000 reduces the depreciation expense shown on Schedule D-21 and is discussed further in the rebuttal of Ms. Ressler (UGI Statement No. 3-R).

- <u>PA and Local Use Tax</u>: In its response to OCA-III-18, the Company identified that the initial filing erroneously included **[BEGIN CONFIDENTIAL]** $77,000 **[END CONFIDENTIAL]** of taxes related to Maryland and West Virginia. A revised Schedule D-31 reflects this adjustment, which is discussed in further detail in my rebuttal testimony (Section IV.F below).

- <u>Depreciation on Allowance for Funds Used During Construction ("AFUDC") Regulatory Asset</u>: In its response to discovery question I&E-RB-42, the Company stated that it inadvertently reflected a 5-year amortization for this asset instead of a 40-year amortization in Book VIII, Page II-3. The difference between annual depreciation expense at a 40-year life vs. a 5-year life is $230,792. This adjustment for $230,792 is reflected in Schedule D-21. Additionally, a corresponding decrease of $461,673 was made to the accumulated depreciation on Schedule C-3. These adjustments are further outlined in the rebuttal testimony of Vivian K. Ressler (UGI Gas Statement No. 3-R).

- Salary and Wage Adjustment for Cybersecurity Positions: As explained in the Company's response and Attachment to OCA-III-12, the Company is reflecting an increase of $87,323 to its cybersecurity salary and wage adjustment in its original filing. A revised Schedule D-9 is provided as an exhibit to my rebuttal testimony.

- Interest on Customer Deposits: The Company accepts I&E's recommended adjustment to reduce the interest expense on customer deposits in the amount of $324,000. This adjustment is discussed further in my rebuttal testimony (Section III.B below). A corrected Schedule D-15 is provided as an exhibit to my rebuttal testimony to reflect this adjustment.

- Embedded Cost of Long-Term Debt: The Company is revising the interest rate on three debt issuances to be issued in the future test year ("FTY") and the fully projected future test year ("FPFTY"). The interest rate for note #12 is increasing from 3.687% to 4.744%. Interest on note #13 is increasing from 1.410% to 4.003%, and the interest on note #14 is increasing from 3.791% to 4.744%. These adjustments are discussed further in the rebuttal testimony of Paul R. Moul (UGI Gas Statement No. 6-R). In addition, a revised Schedule B-6 (Cost of Debt) and Schedule B-7 (Rate of Return) are provided to represent these increases.

- Plant in Service: As explained in the rebuttal testimony of Vicky A. Schappell (UGI Gas Statement No. 5-R) and the Company's response in I&E-RB-4-D (Supplemental), the Company is reducing its plant in-service amount for the FTY by $699,849 and increasing its plant in-service amount for the FPFTY by $28,964. This adjustment is reflected on a revised Schedule C-2. Additionally, a corresponding decrease of $19,260 for the FPFTY was made to the accumulated depreciation on Schedule C-3. The accumulated depreciation adjustment is further explained in the rebuttal testimony of Vivian K. Ressler (UGI Gas Statement No. 3-R).

- Gas Inventory Balance: The Company is updating the period over which its average Gas Inventory balance is calculated within its lead/lag study to reflect the use of the 13-month average balance as of April 2022, which results in a net increase in rate base of $7,281,000. This adjustment is discussed further in the rebuttal testimony of Vivian K. Ressler (UGI Gas St. No. 3-R). In addition, a revised Schedule C-5 is provided as an exhibit to my rebuttal testimony to reflect this adjustment.

- Customer Deposit Balance: The Company is updating the period over which its average Customer Deposit balance is calculated within its lead/lag study to reflect the use of the 13-month average balance as of April 2022, which resulted in a net increase in rate base of $166,000. This adjustment is discussed further in the rebuttal testimony of Vivian K. Ressler (UGI Gas St. No. 3-R). In addition, a revised Schedule C-7 is provided as an exhibit to my rebuttal testimony to reflect this adjustment.

- Materials and Supply Balance: The Company is updating the period over which its average Materials & Supplies balance is calculated within its lead/lag study to reflect the use of the 13-month average balance as of April 2022, which resulted in a net increase in rate base of $852,000. This adjustment is discussed further in the rebuttal testimony of Vivian K. Ressler (UGI Gas St. No. 3-R). In addition, a revised Schedule C-8 is provided as an exhibit to my rebuttal testimony to reflect this adjustment.

- Accumulated Deferred Income Tax ("ADIT"): The Company recalculated its ADIT based upon the accumulated depreciation revisions discussed above. A net increase of $85,000 is shown on Schedule C-6 and discussed in further detail in the rebuttal testimony of Vivian K. Ressler (UGI Gas St. No. 3-R).

- Payroll Expense: The Company accepts OCA's adjustment to reduce headcount by 17 employees, as discussed in Section IV.C of my rebuttal. This headcount reduction results in a $779,000 decrease to payroll expense as shown in Schedule D-18, which is provided as an exhibit to my testimony.

- Employee Benefits Expense: Based on the Company's headcount adjustment, a corresponding decrease to benefits expense will be made to decrease the expense by $95,000, as discussed in the rebuttal testimony of Vivian K. Ressler (UGI Gas St. No. 3-R). In addition, Schedule D-18 is provided as an exhibit to my rebuttal testimony to reflect this adjustment.

- Inflation Adjustment for Outside Contractors: The Company is increasing its claim for additional inflation-related costs to its expenses for outside contractor labor. The increase of $2,692,000 is discussed in the rebuttal of Timothy J. Angstadt (UGI Gas St. No. 9-R) and is shown in Schedule D-18, which is provided as an exhibit to my rebuttal testimony.

Each of these updates to the Company's rate base and operating expenses is reflected in UGI Gas Exhibit A – Fully Projected (REBUTTAL), which is the Company's final accounting exhibit.

Q. Since the filing of your direct testimony, has the Company identified any revenue components of its filing that should be updated?

A. Yes, the Company also identified the following revenue item that requires revision for the FPFTY ending September 30, 2023:

- Company Share of Off-System Sales Revenue: In its response to discovery question I&E-RS-27, the Company identified that it inadvertently included $1,003,000 of miscellaneous revenue for the company share portion of off-system sales that should be reflected below the line for ratemaking purposes. This adjustment is reflected in a revised Schedule D-5.

As with the updates to the Company's costs, this revision to the Company's revenues is reflected in UGI Gas Exhibit A – Fully Projected (REBUTTAL).

Q. Based upon the adjustment analyses conducted by the Company, what do you conclude?

A. As set forth in the Company's final accounting exhibit, "UGI Gas Exhibit A - Fully Projected (REBUTTAL)," the overall effect of the updates and corrections to the Company's claim is that the Company has supported a revenue increase of $87,619,000 (as compared to the as-filed claim of $82,742,000) using the Company's proposed capital structure, revised weighted average cost of debt, and proposed return on equity of 11.20%. While the Company is not requesting that the Pennsylvania Public Utility Commission ("Commission") authorize an increase greater than its as-filed amount, any adjustments proposed by the parties should be applied to the $87,619,000, which is the revenue increase supported by the evidence presented in this case.

III. <u>OPERATING REVENUE ADJUSTMENTS</u>

A. FORFEITED DISCOUNTS, MISCELLANEOUS REVENUES AND RENT FROM GAS PROPERTIES

Q. Do any of the other parties recommend adjustments to the Company's present rate revenues associated with Forfeited Discounts, Miscellaneous Revenues, and Rent from Gas Properties?

A. Yes. OCA witness Mr. Mugrace proposes that the present rate revenues associated with Forfeited Discounts, Miscellaneous Revenues, and Rent from Gas Properties be normalized over a 3-year period of 2021-2023. OCA St. No. 1 at 13. Mr. Mugrace's proposed adjustment uses the balance of revenues shown by the Company for the historic test year ("HTY"), FTY and FPFTY, and would increase present rate revenues by $413,667. OCA St. No. 1 at 13; *see also* OCA Schedule DM-4.

Additionally, the Company would like to correct the FTY revenue shown on page 13 of Mr. Mugrace's testimony. For the FTY, Mr. Mugrace states that the Forfeited Discounts, Miscellaneous Revenues and Rent from Gas Properties totals $19,181,000. However, as shown in UGI Gas Exhibit A – Future, Schedule D-1, Line 3, the FTY revenue is $10,181,000.

Q. Please summarize the basis for OCA witness Mr. Mugrace's proposed adjustment.

A. Mr. Mugrace states that he is "of the opinion that these types of revenues do fluctuate and change from year to year, and it is appropriate to normalize these revenues, including forecasted revenues, prospectively." OCA St. No. 1 at 13.

Q. Does the Company agree with Mr. Mugrace's proposed adjustment to present rate revenues?

A. No, for two reasons.

Q. What are those two reasons?

A. First, as stated in the Company's responses to discovery requests I&E-RS-25, I&E-RS-26 and I&E-RS-27, the Company prepared the FTY and FPFTY revenue projections based on monthly three-year averages of historical data for each revenue category. Adding additional averaging of revenue as Mr. Mugrace is suggesting is unnecessary.

Second, as mentioned in Section II of my rebuttal testimony and noted in the Company's response to discovery request I&E-RS-27, the Company is adjusting its miscellaneous revenue in the FPFTY downward by $1,003,000 to $9,284,000 to remove the Company's share of off-system sales. Mr. Mugrace's analysis did not include this correction, which was accepted by I&E witness Ethan H. Cline (I&E St. No. 4 at 22). By way of comparison, removing the company share revenue erroneously included in the FTY and HTY would decrease the miscellaneous revenue to $9,178,000 and $10,254,000 respectively.

IV. OPERATING EXPENSE ADJUSTMENTS

A. RATE CASE EXPENSE

Q. What did the Company propose regarding rate case expense?

A. The Company proposed to recover rate case expenses totaling $1,055,000 normalized over a one-year period.

Q. Was this proposal contested by any of the parties?

A. Yes. I&E witness Mr. LaTorre recommends that a 20-month normalization period be used to calculate the Company's rate case expense claim in this case. I&E St. No. 3 at 4. This adjustment would reduce the Company's rate case expense claim by $422,000. I&E St. No. 3 at 4. Mr. LaTorre asserts that the Company's historic filing frequency, based on its last three base rate cases, is 20 months on average. I&E St. No. 3 at 5. He further cites prior Commission orders in *Emporium Water 2015*,[1] *City of DuBois Water 2017*,[2] *Columbia Gas 2020*,[3] and *PECO Gas 2021*[4] to argue that actual historical filing frequency is more reliable than a Company's projected filing of a future rate case. I&E St. No. 3 at 6-7.

OCA witness Mr. Mugrace similarly recommends that the Commission reduce the Company's claimed rate case expense. OCA St. No. 1 at 38-39. He argues that a 2-year normalization period should be used, which would reduce the Company's claim by $527,000.

Q. Does the Company agree with the adjustments proposed by I&E and the OCA?

A. No, it does not.

Q. Please explain why a 20-month normalization period, as proposed by I&E, and a 2-year normalization period, as proposed by OCA, are both improper.

A. The frequency of UGI Gas's past base rate cases is not a predictor of the frequency of future base rate cases. In particular, the time frame between the Company's most recent base rate proceeding at Docket No. R-2019-3015162 and the current one was subject to a one-year settlement stay-out clause that prohibited the Company from making a base rate filing earlier than January 2, 2022, effectively adding one year to the period when the

[1] *Pa. PUC v. Emporium Water Company*, Docket No. R-2014-2402324, pp. 47-50 (Order Entered Jan. 28, 2015).

[2] *Pa. PUC v. City of DuBois – Bureau of Water*, Docket No. R-2016-2554150, pp. 65-66 (Order Entered March 28, 2017); *Pa. PUC v. City of DuBois – Bureau of Water*, Docket No. R-2016-2554150, p. 13 (Order Entered May 18, 2017).

[3] *Pa. PUC v. Columbia Gas*, Docket No. R-2020-3018835, pp. 78-79 (Order Entered Feb. 19, 2021).

[4] *Pa. PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, pp. 117-119 (Non-Proprietary Order Entered June 22, 2021).

Company could not make a filing. Removing that 1-year period would reduce the normalization period proposed by I&E and would result in a 16- month normalization period [(12 months + 12 months + 24 months)/3 = 16 months]. Mr. Mugrace's recommendation is not supported by any particular rationale and should be rejected outright.

Moreover, the Company's expectation that it will file another base rate case in one year is based upon an assessment of future capital requirements, continued information system improvements through the UNITE project, and the cost of other improvements as detailed in the Company's second Long-Term Infrastructure Improvement Plan ("LTIIP") filing.[5] At the same time, all of the Company's operating expenses are subject to inflation, and the revenue requirements for plant additions that are not Distribution System Improvement Charge ("DSIC")-eligible will cause further pressure to file a rate case within one year after the rates in this case become effective. By way of further explanation, the Company is implementing a significantly accelerated replacement and betterment program as detailed in its Second LTIIP. This accelerated spend, in conjunction with other capital requirements and operating expenses, support a one-year rate case cycle and a one-year normalization of rate case expenses.

Other factors supporting the Company's one-year normalization period include rising inflation, capital cost rates and higher risks associated with a rate of return that will reflect and be supportive of the Company's financial and risk profile, as explained in the rebuttal testimony of Paul R. Moul (UGI Gas St. No. 6-R). Additionally, the possibility of

[5] See Petition of UGI Utilities, Inc. – Gas Division for Approval of its Second Long Term Infrastructure Improvement Plan, Docket No. P-2019-3012337 (Opinion and Order entered Dec. 19, 2019).

reaching the current 5 percent DSIC cap after the new rates established in this case become effective can be a factor that influences more frequent rate case filings. Thus, to the extent that the Company is subject to a DSIC maximum rate of 5 percent, the Company's earnings will suffer from attrition due to the DSIC cap. Such an occurrence can be a deciding factor in the relative frequency of rate case filings. Therefore, the Company's claimed rate case expense and associated normalization period are reasonable and should be adopted.

Q. Are there any other reasons why the Commission should differentiate between the facts presented in the aforementioned rate proceedings and this case?

A. I am advised by counsel that I&E's reliance on *Emporium Water 2015*, *City of DuBois Water 2017*, disregards the fact that its exclusive reliance upon historic rate case filing frequency was rejected by the Commission in *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058 (Order entered Oct. 25, 2018) ("*UGI Electric 2018*"). Moreover, I am further advised by counsel that I&E ignores the fact that in *Columbia Gas 2020*, none of the parties filed exceptions on this issue and that Columbia specifically did not take exception to many issues in recognition of the unique circumstances posed by the COVID-19 pandemic. As such, both *Columbia Gas 2020* and *PECO Gas 2021* (which relies on the Commission's determination in *Columbia Gas 2020*) are distinguishable from the instant case. It is my understanding that UGI Gas will further address I&E's reliance on these cases in its briefs.

B. INTEREST ON CUSTOMER DEPOSITS

Q. Did any of the other parties propose adjustments to the Company's claimed expenses associated with the interest it is required to pay on customer deposits that it holds in compliance with its tariff?

A. Yes. I&E witness Mr. Walker disputed the Company's claimed revenues associated with interest on customer deposits. I&E St. No. 1 at 16. He argues that the Company's claimed interest rate of 4.5% is speculative and that the current interest rate of 3.0% should be used in the calculation.

Q. Please summarize the basis for Mr. Walker's proposed adjustment.

A. Mr. Walker based his adjustment upon the Pennsylvania Secretary of Revenue's current interest rate for Title 72 taxes for 2021 and 2022, which is 3%. I&E St. No. 1 at 16. He further claims that although this rate may be revised by the Pennsylvania Department of Revenue in December 2022 the 4.5% rate as of today is speculative. I&E St. No. 1 at 16.

Q. Does the Company agree with Mr. Walker's proposed adjustment?

A. Yes. As noted in Section II of my rebuttal, a corrected Schedule D-15 is provided in Exhibit A – FPFTY (REBUTTAL).

C. PAYROLL EXPENSE

Q. Did any of the other parties propose adjustments to the Company's claimed Payroll Expense for the FPFTY?

A. Yes. Both I&E witness Mr. Walker and OCA witness Mr. Mugrace propose adjustments to this expense category.

Q. Please summarize the adjustment proposed by I&E witness Mr. Walker.

A. I&E witness Mr. Walker proposed a reduction of $2,251,676 to the Company's claim. I&E St. No. 1 at 18. He calculated this adjustment using a 2.74% average vacancy rate, which he based on the actual monthly vacancies by budgeted positions for each month of FY 2019, 2020 and 2021 and then averaged the fiscal year averages. I&E St. No. 1 at 19-20. Mr. Walker further asserts that his proposed adjustment is reasonable because the COVID-19 pandemic may continue to present the Company with challenges in filling all budgeted positions. I&E St. No. 1 at 20.

Q. Please summarize the adjustment proposed by OCA witness Mr. Mugrace.

A. Mr. Mugrace generally accepted the Company's projected employee headcount, but proposed to reduce the Company's Payroll Expense by $779,368 to exclude 17 open positions relating to replacement for which candidates have yet been identified. OCA St. No. 1 at 20-21. Mr. Mugrace argues that these positions may or may not be filled in FY 2023 and, therefore are speculative. OCA St. No. 1 at 20-21. He also asserts that the Company's response to OCA-III-7 indicates that the Company anticipates hiring these positions based on the labor market and other factors. OCA St. No. 1 at 21.

Q. Does the Company agree with either adjustment proposed by I&E or OCA?

A. Yes. The Company accepts Mr. Mugrace's adjustment of $779,368 to payroll expense. However, the Company believes that Mr. Walker's adjustment is biased because it is heavily weighted by the COVID-19 year of 2019. If an average is used, it should be based on the monthly averages of FY19 and FY21. COVID-19 substantially impacted hiring during FY20 and should not be included to calculate a vacancy rate under normal conditions for ratemaking purposes. Removing the impact of FY20 would bring the vacancy rate down to 1.59%. Additionally, neither party denied these positions on merit or their necessity to provide safe and reliable service.

D. EMPLOYEE BENEFITS – HEADCOUNT

Q. Do any of the other parties propose an adjustment to the Company's claimed Employee Benefits expense?

A. Yes. I&E witness Mr. Walker proposes a reduction to the Company's Employee Benefits expense based upon his proposed vacancy adjustment. I&E St. No. 1 at 21-22. The impact of his adjustment would be a reduction to this expense of $606,006. I&E St. No. 1 at 21-22. OCA witness Mr. Mugrace is proposing to normalize the Company's medical and dental costs over FY 2021-2023. Mr. Mugrace states that this normalization takes into account his recommended reduction in headcount. OCA. St. No. 1 at 50.

Q. Does the Company agree with either I&E's or OCA's proposed adjustment to Employee Benefits based upon their adjustments to projected employee headcount?

A. No. The Company disagrees with I&E's adjustment, which is derivative of its proposed adjustment to the Company's projected employee headcount for the FPFTY. However, as explained in the testimony of UGI Gas witness Ms. Ressler (UGI Gas St. No. 3-R), the Company is adjusting its benefits expense based on the OCA Witness's headcount adjustment. Additionally, Ms. Ressler responds to Mr. Mugrace's proposal to normalize medical and dental costs.

E. PAYROLL TAX

Q. Do any of the other parties propose an adjustment to the Company's claimed Payroll Tax expense?

A. Yes. OCA witness Mr. Mugrace similarly recommends a reduction of $438,185 to the Company's claim, which is based upon his adjustment to the Company's projected employee headcount and certain Incentive Compensation adjustments[6] that are reflected in the Company's payroll rates. OCA St. No. 1 at 53.

Q. Does the Company agree with either I&E's or OCA's proposed adjustment to Payroll Tax Expense?

A. Yes, with some qualifications. As noted previously, the Company agrees with Mr. Mugrace's position to reduce payroll expense by $779,000, which lowers payroll tax expense by $57,000. However, the Company disagrees with the remaining $381,185 of Mr. Mugrace's adjustment as it is derivative of his proposed adjustment to Incentive Compensation, which the Company does not accept. This position is further explained in the rebuttal of Ms. Ressler (UGI Gas St. No. 3-R).

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[6] UGI Gas witness Ms. Ressler addresses Mr. Mugrace's proposed Incentive Compensation adjustments in her rebuttal testimony, UGI Gas St. No. 3-R.

F. STATE AND LOCAL TAX EXPENSE

Q. Did any of the other parties propose an adjustment to the Company's claim for Pennsylvania State and Local tax expense.

A. Yes. OCA witness Mr. Mugrace proposed to reduce the Company's claim by **[BEGIN CONFIDENTIAL]** $77,000 **[END CONFIDENTIAL]** OCA St. No. 1 at 53. Mr. Mugrace asserts that the Company's response and Attachment to OCA-III-18(2) shows that the Company overstated its claim by this amount.

Q. Does the Company agree with OCA's proposed adjustment to this expense?

A. Yes. As mentioned in Section II of my rebuttal, a revised Schedule D-31 is provided in Exhibit A – FPFTY (REBUTTAL).

G. CASH WORKING CAPITAL

Q. What was the Company's claim for cashing working capital ("CWC") in its initial filing?

A. The Company claimed $62,148,000 in CWC in its filing.

Q. Has the Company identified any adjustments to its initial CWC claim?

A. The Company is adjusting its CWC claim to $61,697,000 based upon the adjustments explained in Section II of my rebuttal and their impact to operations and maintenance ("O&M") expenses and interest payment components in the CWC.

Q. Did any party propose any adjustments to the Company's original CWC claim?

A. Yes. I&E witness Mr. Walker recommends reducing the CWC claim to $61,313,000, which is a reduction of $835,000. I&E St. No. 1 at 24. This reduction is based on the O&M expense adjustments recommended by I&E. I&E St. No. 1 at 25. OCA witness Mr. Mugrace similarly proposed to decrease by $587,278 the Company's CWC claim to reflect his recommended adjustments to operating and maintenance expenses. OCA St. No. 1 at 10-11.

Q. Does the Company agree with either I&E's or OCA's CWC adjustments?

A. The Company disagrees with their adjustments to the extent that the Company disagrees with their underlying expense or tax adjustments.

Q. Please provide more detail on why the Company does not agree with the CWC adjustments proposed by I&E and OCA.

A. As previously stated, both I&E's and OCA's CWC adjustments are based solely on their respective recommended expense adjustments. As explained earlier in my testimony summarizing adjustments that the Company is making in rebuttal, consistent with the Company's response in discovery, I agree with Mr. Walker's proposal to reduce the CWC claim by $34,000 due to the reduction of interest expense on customer deposits in the Company's initial claim. However, I do not agree with all of Mr. Walker's additional adjustment, which impacts the CWC in the amount of $801,000. Mr. Walker's allowance for O&M expense in his CWC analysis represents a downward adjustment in the amount of $964,000 of this balance (inclusive of the $34,000 above). The Company also rejects the payroll adjustment from I&E as well as the purchase gas adjustment. Mr. Walker proposed adjustments to Other Expenses in the CWC claim, including O&M reductions totaling $6,338,328 ($6,662,328 of total Other Expenses - $324,000 of Interest on Customer Deposits)[7], which the Company rejects, except for a portion of the OSHA/ETS Compliance cost adjustments related to the costs incurred by the Company for legal advice and vaccine tracking software. Mr. Walker's adjustment to CWC also includes a revenue lag adjustment which the Company rejects, except for the $1,003,000 correction of miscellaneous revenue to reduce present rate revenue. I&E St. No. 1 at 27. Finally, Mr. Walker's interest payment component includes a rate base adjustment that includes a reduction to rate base, which the Company rejects, as discussed in Ms. Ressler's testimony (UGI Gas Statement No. 3-R).

I do not agree with the majority of Mr. Mugrace's O&M expense adjustments in the amount of $33,940,000 (OCA Schedule DM-4), which reduces the CWC claim in the amount of $587,278. As discussed previously in my testimony, the Company accepts his payroll expense adjustment of $779,368, a portion of his employee benefits adjustment in the amount of $95,000, and a portion of OCA's payroll tax adjustment in the amount of $57,000. His adjustments to Other Expenses include reductions totaling $33,008,632, which the Company rejects. OCA Schedule DM-4.

Mr. Mugrace's interest payment component includes a rate base adjustment that includes a reduction to net plant in service in the amount of $85,681,967 (OCA Schedule DM-5) that the Company rejects, as discussed in Ms. Ressler's rebuttal testimony (UGI Gas St. No. 3-R), as well as a capital structure based on a 50% long term debt ratio which the Company also rejects, as discussed in UGI Gas witness Paul R. Moul's rebuttal

[7] Mr. Walker's adjustments to Other Expenses appear in his table titled "Other Expenses" on p. 26 of his direct testimony. I&E St. No. 1 at 26.

testimony (UGI Gas St. No. 6-R). The tax payment component reflects the overall impact of all the adjustments and a reduced revenue requirement which reduces income taxes.

V. INTEREST SYNCHRONIZATION ADJUSTMENT TO INCOME TAX EXPENSE

Q. What was the Company's original claim for income tax expense in this proceeding?

A. The Company's claim for income tax expense in this proceeding was $63,348,000 as reported on Schedule D-33 of UGI Gas Exhibit A (FPFTY). Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of Federal income taxes, and the flow through of accelerated depreciation benefits for state tax purposes. The Company's claimed interest expense deduction was $56,726,000 based on a rate base of $3,169,023,000 multiplied by the weighted cost of debt of 1.79 % (44.91 % x 3.98 %) UGI Gas Exhibit A (FPFTY), Schedule B-7.

Q. Did any party challenge the Company's claim?

A. Yes. OCA witness Mr. Mugrace recommends an interest expense deduction of $61,437,244 based upon OCA's recommended adjustments to rate base and capital structure. OCA St. No. 1 at 54.

Q. Do you agree with Mr. Mugrace's proposed adjustment?

A. No. I note that UGI Gas witness Mr. Moul responds specifically to the OCA's proposed, capital structure, cost of equity and overall rate of return in his rebuttal testimony (UGI Gas St. No. 6-R). For the reasons fully identified in Mr. Moul's rebuttal testimony, OCA witness David J. Garrett's adjustments (in OCA St. No. 2) to the Company's actual capital structure and cost of equity should be rejected and so should Mr. Mugrace's adoption of that recommendation in OCA's revenue requirement model. In addition, Mr. Mugrace proposed adjustments to the Company's filed rate base, which decrease the rate base balance by $81,724,823 to $3,087,298,717. *See* OCA Schedule DM-3. These rate base adjustments are discussed in the rebuttal testimonies of UGI Gas witnesses Vivian K. Ressler (UGI Gas St. No. 3-R) and Vicky A. Schappell (UGI Gas St. No. 5-R).

Q. Are there other adjustments made by the Company as part of its Rebuttal Case?

A. As discussed earlier, the Company has reflected an adjustment to the average cost of long-term debt, which increases the rate from 3.98% to 4.30%. In addition, the Company has increased its rate base claim by $7,573,000 to $3,176,596,000. These adjustments increase the interest deduction by $4,582,000 to $61,308,000 (based on a rate base of $3,176,596,000 multiplied by the weighted cost of debt of 1.93% (44.91% x 4.30%) UGI Gas Exhibit A – Fully Projected Future (REBUTTAL), Schedule B-7. The interest increase of $4,582,000 decreases the state and federal income taxes by $41,000 and $77,000, respectively.

VI. COMPLIANCE WITH PENNSYLVANIA ACT 40 OF 2016

Q. Did your direct testimony include a discussion of the requirements of Pennsylvania Act 40 of 2017 ("PA Act 40" or "Act 40")?

A. Yes, it did.

Q. Did any other parties address the PA Act 40 requirements?

A. Yes, in OCA Statement No. 1, Mr. Mugrace addresses the PA Act 40 requirements. While Mr. Mugrace accepts the Company's satisfaction of Act 40's requirement that 50% of the hypothetical Consolidated Tax Adjustment ("CTA")is being used to support reliability or infrastructure related to the rate-base eligible capital investment, he argues that the Company has not demonstrated the remaining 50% is being used for "general corporate purposes." OCA St. No. 1 at 56-57. Mr. Mugrace asserts that "general corporate purposes" means to provide regulated utility service in Pennsylvania, which requires that this amount be used as a source of non-investor-supplied funding for utility working capital and to reduce rate base. OCA St. No. 1 at 57. He also claims that UGI Gas has not identified how this amount will be used to benefit rate payers. OCA St. No. 1 at 57. As such, he recommends that the Company's rate base be reduced by $1.27 million. OCA St. No. 1 at 58; *see also* OCA Schedule DM-3.

Q. Does Mr. Mugrace define the term "general corporate purposes?

A. Mr. Mugrace states that the term "general corporate purposes" would include uses such as "supporting capital expenditures necessary to execute utility business plans, paying off debt, funding construction projects, paying dividends, paying for maintenance and operating expenses, investing in utility plant in Pennsylvania, and providing a source of working capital." OCA St. No. 1 at 57.

Q. To be clear, is the Company using 50% of the amount calculated pursuant to Act 40 for these purposes?

A. Yes. 50% of the amount calculated in this proceeding will in fact be used for general corporate purposes, as that term is understood.

Q. Can you provide any examples of categories of projects that this amount will be used to support?

A. Yes. While it is not practical to trace a hypothetical amount to specific projects, 50% of the Act 40 amount will be used to pay for general operating expenses of the Company. As shown in UGI Gas Exhibit A – FPFTY, Schedule B-4, the Company's total budgeted O&M expense is $625,766,000. These expenses will be used to the benefit of ratepayers, including $2.177 million in meter reading expenses, $28.149 million for the maintenance of mains, and $35.342 million for various customer service expenses. Therefore, UGI Gas spends over 50% of the hypothetical CTA on general expenditures that are specifically for the purpose of providing utility service to ratepayers.

Q. Are there any other reasons why Mr. Mugrace's claims lack merit?

A. Yes. PA Act 40 added 66 Pa. C.S. §1301.1 to the Public Utility Code, which provides, in pertinent part:

> (b) Revenue use -- If a differential accrues to a public utility resulting from applying the ratemaking methods employed by the commission prior to the effective date of subsection (a) for ratemaking purposes, the differential shall be used as follows:
>
> > (1) fifty percent to support reliability or infrastructure related to the rate-base eligible capital investment as determined by the commission; and
> >
> > (2) fifty percent for general corporate purposes.

I am advised by counsel that the application of statutory construction rules to this language does not support Mr. Mugrace's interpretation of this language, and that utilities need only show that their capital expenditures, and expenditure on other general corporate purposes, exceed fifty percent of the differential in tax expense resulting from Act 40. In the case of UGI Gas, both its capital expenditure and general corporate purpose expense exceed the fifty percent thresholds referenced in 66 Pa. C.S. §1301(b) by wide margins and therefore the Company has made the necessary showing that its use of the differential satisfies the plain language of Section 1301.1(b). Thus, UGI Gas is fully entitled to recover tax expense in the manner authorized by Act 40 without reduction. As quantified in my direct testimony, the impact of the 50% to be used for "general corporate purposes" is $1.825 million.

Q. Has the Commission previously determined that UGI has satisfied the showing required by PA Act 40 by producing similar evidence that it has in this case.

A. Yes. In the 2018 UGI Utilities, Inc. – Electric Division ("UGI Electric") base rate case, Docket No. R-2017-2640058, the Commission specifically concluded that UGI Electric satisfied Act 40 by making the same presentation it has made in this case.

Consistent with the language of Section 1301.1, the Commission determined that UGI Electric had properly complied with the requirements of Act 40 by showing that the Company's *pro forma* capital additions for reliability or infrastructure projects in the FTY and FPFTY exceeded 50% of the amount of what would have been the CTA, and that the Company's general corporate purpose expense would also exceed 50% of the tax benefit resulting from the elimination of the CTA.

Q. Was the Commission's determination in that case affirmed on appeal?

A. Yes. In *McCloskey v. Pa. PUC*, 225 A.3d 192 (Pa. Cmwlth. 2020), the Commonwealth Court affirmed the Commission's determination in the UGI Electric base rate case.

Q. In this case, has the Company provided additional evidence regarding its compliance with Act 40, specifically with the requirement that 50% of the hypothetical CTA be used for general corporate purposes?

A. Yes. The testimony presented by the Company in its direct testimony in this case is similar to the testimony that was accepted by the presiding Administrative Law Judges and the Commission in the Company's 2018 Electric Division rate case. In summary, the O&M budget for general corporate purposes far exceeds 50% of the tax benefit resulting from the elimination of the CTA.

Q. Based on his faulty assumption that 50% of the hypothetical CTA is not used for general corporate purposes, Mr. Mugrace recommends an adjustment to the Company's rate base of $1.277 million. How do you respond to his adjustment?

A. Mr. Mugrace's adjustment should be rejected because, as I explained, UGI Gas has complied with Act 40's requirements to use 50% of the hypothetical CTA for general corporate purposes. Although Mr. Mugrace is attempting to frame his adjustment as an adjustment to rate base, rather than as an adjustment to tax expense, the adjustment is still based on the incorrect theory that UGI Gas has not complied with the requirements of 66 Pa. C.S. §1301(b), and therefore it should be rejected.

Q. Do you have any additional concerns regarding the use of a CTA offset to rate base?

A. While it is unclear that placing the CTA as a deduction to rate base would result in a tax normalization violation, the IRS has taken the position on both sides of the issue, thereby raising the risk of an adverse IRS ruling on the issues. Adopting Mr. Mugrace's adjustment therefore potentially jeopardizes the loss of $628.595 million of ADIT to the detriment of our customers and adversely impacts the cash position of the Company, as those taxes may become due immediately. That risk clearly overwhelms the minor benefit for customers that would result from Mr. Mugrace's adjustment for tax benefits that are not the result of UGI Utilities' activities but rather the activities of the Company's non-regulated affiliates.

VII. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

CONFIDENTIAL VERSION

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 3-R

Rebuttal Testimony of
Vivian K. Ressler

Topics Addressed:	**Updates And Corrections To Initial Filing** **Response To Rate Base Adjustments** **Response To Operating Expense Adjustments** **Miscellaneous**

Dated: May 17, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 3, on January 28, 2022.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony provides updates to certain rate base and operating expense components of the Company's filing, based on the information provided during the discovery phase of this proceeding. In addition, my testimony responds to certain portions of the following direct testimony submitted by the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"): I&E Statement No. 1, the direct testimony of Zachari Walker; I&E Statement No. 3, the direct testimony of Brian J. LaTorre; I&E Statement No. 5, the direct testimony of Esyan A. Sakaya; and OCA Statement No. 1, the direct testimony of Dante Mugrace. Finally, my direct testimony introduces a miscellaneous revenue matter which is further discussed within the rebuttal testimony of UGI Gas witness Constance E. Heppenstall (UGI Gas St. No. 10-R).

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Gas Exhibits VKR-1R through 11R. These exhibits include CONFIDENTIAL UGI Gas Exhibits VKR-5R, 6R and 8R.

II. UPDATES AND CORRECTIONS TO THE COMPANY'S CLAIM

Q. Since the filing of your direct testimony, has the Company identified any rate base components of its filing that should be updated?

A. Yes, during the discovery phase of this proceeding, the Company identified parts of its initial filing that required revision. These include the following:

- The Company has updated the period over which its average Gas Inventory balance is calculated (UGI Gas Exhibit A - Fully Projected (REBUTTAL), Schedule C-5) to reflect the use of the 13-month average balance as of April 2022, which resulted in a net increase in rate base of $7,281,000;
- The Company has updated the period over which its average Customer Deposit balance is calculated (UGI Gas Exhibit A - Fully Projected (REBUTTAL), Schedule C-7) to reflect the use of the 13-month average balance as of April 2022, which resulted in a net increase in rate base of $166,000;
- The Company has updated the period over which its average Materials & Supplies balance is calculated (UGI Gas Exhibit A - Fully Projected (REBUTTAL), Schedule C-8) to reflect the use of the 13-month average balance as of April 2022, which resulted in a net increase in rate base of $852,000; and
- In connection with the update to Plant in Service which is discussed in the rebuttal testimony of UGI Gas witness Vicky A. Schappell (UGI Gas St. No. 5-R) and the depreciation expense adjustments discussed directly below, the Company has reduced its accumulated depreciation balance by $481,000 and has increased its accumulated deferred income taxes ("ADIT") balance by $85,000. These adjustments result in a $396,000 increase to rate base.

Each of these updates to the Company's rate base is reflected in UGI Gas Exhibit A (REBUTTAL), which is the Company's final accounting exhibit. UGI Gas witness Ms. Tracy A. Hazenstab sponsors this exhibit as a part of her rebuttal testimony (UGI Gas St. No. 2-R).

Q. Since the filing of your direct testimony, has the Company identified any operating expense components of its filing that should be updated?

A. Yes, as with the aforementioned rate base items, in addition to items discussed by Company witness Christopher R. Brown in UGI Gas Statement No. 1-R and Company witness Tracy A. Hazenstab in UGI Gas Statement No. 2-R, the Company also identified the following operating expense items that required revision for the FPFTY:

- The Company has reduced the employee headcount claim reflected in its claim by 17 positions, or roughly 1%, as discussed within the rebuttal testimony of UGI Gas witness Tracy A. Hazenstab (UGI Gas St. No. 2-R). In connection with this adjustment, the Company also reduced its claim for medical and dental costs by 1%, or $95,065. See further discussion of this adjustment in Section F below.

- The Company has reduced its claim for United States Department of Labor's Office of Safety and Health Administration ("OSHA") / Emergency Temporary Standard ("ETS") Compliance costs, which results in a decrease of $1,830,000 to operating expenses. As indicated within my response to discovery request OCA-III-25, the Company is reducing substantially all of its original claim of $1,883,000 associated with costs for complying the Federal Mandate for vaccination and testing requirements. However, the Company is maintaining the portion of its claim for recovery of certain costs in the amount of $52,934 that were incurred in preparation for compliance with this mandate prior to it being overturned by the Supreme Court of the United States. See further discussion of these maintained costs in Section H below.

- The Company has reduced its claim for depreciation expense upon identifying the following:

  a) that certain allocations to affiliates for depreciation expense on a shared IT asset were mistakenly excluded from its rate claim ($524,000);

  b) that depreciation was claimed for a certain asset at an inappropriate rate, indicated within my response to discovery request I&E-RE-42 ($231,000); and

  c) that certain assets were incorrectly included in or excluded from plant in service in the claim, as discussed in the rebuttal testimony of UGI Gas witness Vicky A. Schappell (UGI Gas St. No. 5-R) ($18,000).

  These depreciation expense adjustments collectively result in a decrease to operating expense of $773,000. Please see details at UGI Gas Exhibit VKR-1R.

As with the updates to the Company's rate base, each of these revisions to the Company's operating expenses are reflected in UGI Gas Exhibit A (REBUTTAL).

III. <u>RATE BASE ADJUSTMENTS</u>

A. UTILITY PLANT IN SERVICE

Q. Do any of the other parties propose adjustments to the Company's claimed utility plant in service as of the future test year ending September 30, 2022 ("FTY") and/or the FPFTY?

A. Yes. Both I&E and OCA propose adjustments to the Company's claim.

Q. Does the Company agree with the adjustments proposed by I&E and OCA?

A. No. In her rebuttal testimony, UGI Gas witness Ms. Vicky A. Schappell (UGI Gas St. No. 5-R) fully explains and rebuts the adjustments advanced by I&E and OCA to the Company's claimed utility plant in service for the FTY and FPFTY. As Ms. Schappell demonstrates, the adjustments proposed by the OCA and I&E witnesses are neither reasonable nor appropriate. Therefore, as I fully explain below, the derivative adjustments to other aspects of the Company's rate base and its operating expenses advanced by I&E and OCA should also be rejected.

B. ACCUMULATED DEPRECIATION

Q. Do any of the other parties propose an adjustment to the Company's claim for accumulated depreciation?

A. Yes. I&E witness Mr. Sakaya recommends that the Company's claim for accumulated depreciation be increased by $16,196,000 (*i.e.*, from $1,318,560,000 to $1,334,756,000).

I&E St. No. 5 at 15, and as revised in Mr. Sakaya's response to discovery response UGI to I&E-II-1. Mr. Sakaya's proposed adjustment is based upon his recommended adjustment to the Company's claimed FTY and FPFTY plant in service. I&E St. No. 5 at 15.

OCA witness Mr. Mugrace similarly accepts the Company's development of its claimed accumulated depreciation balance, but recommends that the Company's claim for accumulated depreciation be decreased by $4,516,613. OCA St. No. 1 at 10; *see also* OCA Schedule DM-6. Mr. Mugrace explains that his proposed adjustment is based upon his proposed adjustments to the Company's utility plant in service claim. OCA St. No. 1 at 10.

Q. Does the Company agree with either of the adjustments proposed by I&E or OCA?

A. No. The Company disagrees with both of these proposed adjustments, which are derivative of I&E's and OCA's proposed adjustments to UGI Gas's utility plant in service claim, for the reasons explained in UGI Gas witness Ms. Schappell's rebuttal testimony (UGI Gas St. No. 5-R).

Q. Does the Company have an update to its claim for accumulated depreciation based upon its proposed adjustment to plant in service?

A. Yes. Based upon the adjustment to plant in service explained by Ms. Schappell (UGI Gas St. No. 5-R) and the depreciation expense adjustment set forth below, the Company has reduced its accumulated depreciation balance by $480,933. See the details of this calculation in UGI Gas Exhibit VKR-1R.

C. ACCUMULATED DEFERRED INCOME TAXES ("ADIT")

Q. Do any of the other parties propose an adjustment to the Company's ADIT claim?

A. Yes. OCA witness Mr. Mugrace recommends a reduction to the Company's ADIT claim of $1,304,944. OCA St. No. 1 at 12; *see also* OCA Schedule DM-8. Mr. Mugrace's adjustment is derived from his proposal to decrease the Company's claim for utility plant in service. OCA St. No. 1 at 12.

Q. Does the Company agree with the adjustment to ADIT that is proposed by OCA?

A. No. The Company disagrees with this adjustment, which is derivative of OCA's proposed adjustment to the Company's utility plant in service claim, for the reasons explained in UGI Gas witness Ms. Schappell's rebuttal testimony (UGI Gas St. No. 5-R).

Q. Does the Company have an update to its claim for ADIT based upon its proposed adjustment to plant in service?

A. Yes. In connection with the update to Plant in Service, which is discussed in the rebuttal testimony of UGI Gas witness Vicky A. Schappell (UGI Gas St. No. 5-R), and the adjustment to Accumulated Depreciation discussed above, the Company has increased its accumulated deferred income taxes ("ADIT") balance by $85,000. See detail of this calculation at UGI Gas Exhibit VKR-1R.

IV. OPERATING EXPENSE ADJUSTMENTS

A. ENVIRONMENTAL REMEDIATION EXPENSE

Q. Do any of the other parties propose an adjustment to the Company's environmental remediation expense claim?

A. Yes. I&E witness Mr. LaTorre and OCA witness Mr. Mugrace each propose adjustments to the Company's claimed environmental remediation expense. I address each of these adjustments in turn, below.

Q. Please summarize I&E witness Mr. LaTorre's adjustment to the Company's environmental remediation expense claim.

A. While Mr. LaTorre accepts the amount claimed for unrecovered environmental remediation expense amortization for Fiscal Year ("FY") 2019 and prior years, he makes two recommendations associated with the Company's claim.

First, Mr. LaTorre recommends that the Company be required to provide a full line-by-line account of yearly amortizations of unrecovered expense in its next base rate case. I&E St. No. 3 at 9. In support of this recommendation, Mr. LaTorre argues that all environmental remediation costs incurred prior to FY 2019 will be extinguished by the time the rates established in the Company's next base rate case go into effect. I&E St. No. 3 at 9-10. He further states that amortization of these amounts should have begun on October 1, 2019 pursuant to the UGI Gas 2019 Base Rate Case Order[1] and the UGI Gas 2020 Base Rate Case Order.[2] I&E St. No. 3 at 10.

[1] *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2018-3006814 (Order Entered Sept. 19, 2019) ("UGI Gas 2019 Base Rate Case Order").

[2] *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2019-3015162 (Order Entered Oct. 8, 2020) ("UGI Gas 2020 Base Rate Case Order").

Second, Mr. LaTorre disagrees with the Company's proposed 1-year amortization period for 2020 and 2021 unrecovered environmental remediation expense. I&E St. No. 3 at 12. He instead recommends that a 5-year amortization period should be used, and, as a result, the Company's claim should be decreased by $1,861,600. I&E St. No. 3 at 12-13.

Q. Does the Company agree with Mr. LaTorre's first recommendation that the Company be required to provide a full line-by-line account of yearly amortizations of unrecovered expense in its next base rate case?

A. Yes.

Q. Is Mr. LaTorre correct that all environmental remediation costs incurred prior to FY 2019 will be extinguished by the time the rates established in the Company's next base rate case go into effect?

A. This cannot be determined at this time. To be clear, the Company appropriately commenced the amortization of these amounts consistent with the UGI Gas 2019 Base Rate Case Order and the UGI Gas 2020 Base Rate Case Order. As shown in UGI Gas Exhibit VKR-2R, the Company began amortizing these amounts in October 2019 and will complete amortization of these amounts in September 2024. Depending on the timing of the Company's next base rate case, the rates associated with this next rate case may be effective before September 2024. Please note that it is the Company's position that it likely will file a new base rate case within one year of the filing of this one, as discussed in Ms. Hazenstab's testimony.

Q. Have you prepared an exhibit to help explain how the Company has amortized under-recovered environmental remediation expense incurred prior to FY 2019?

A. Yes. UGI Gas Exhibit VKR-2R is a schedule that provides, for each under-recovered environmental cost as of September 30, 2021, the amount, the period of amortization, the beginning and ending month for that amortization, the total amortization by fiscal year, and the unrecovered balance as of September 30, 2022. Additionally, the Company will provide a similar schedule in the next rate case filing to assist with the reconciliation of environmental remediation expenses.

Q. Does the Company agree with Mr. LaTorre's second recommendation that a 5-year amortization period should be used for under-recovered environmental remediation expense incurred during FY 2020 and 2021?

A. No.

Q. Please explain.

A. The Company selected a one-year amortization period for unrecovered FY 2020 and FY 2021 costs because it anticipates that it will file for another base rate increase within the next year. I would also note that the time period over which these costs were incurred was the two-year period ending September 30, 2020, and September 30, 2021. As such, there is a serious mismatch between the period in which the costs were incurred and when Mr. LaTorre's 5-year amortization period would allow them to be recovered.

Moreover, Mr. LaTorre's references to the UGI Gas 2019 Base Rate Case Order and the UGI Gas 2020 Base Rate Case Order are misplaced. In fact, each order merely refers to the settlement provision applicable in each case. Thus, the agreement to use a five-year amortization period in either of these prior cases has no bearing on the correct amortization to apply in this proceeding. Additionally, the settlement of a base rate proceeding should have no persuasive value in determining the correct amortization period in this case. As stated in Paragraph 81 of the Joint Petition for Approval of Settlement of All Issues in the UGI Gas Base Rate Proceeding:

> The Joint Petitioners acknowledge that the Settlement reflects a compromise of competing positions and does not necessarily reflect any Joint Petitioner's position with respect to any issues raised in this proceeding. The terms and conditions of the Settlement are limited to the facts of this specific case and are the product of compromise for the sole purpose of settling this case . . . .

Paragraph 63 of the Joint Petition for Approval Settlement of All Issues in the UGI Gas 2020 Base Rate Proceeding includes identical language.

Q. Do you have any further observations regarding Mr. LaTorre's proposal to use a 5-year amortization period for this expense?

A. Yes. Mr. LaTorre also appears to be proposing that the Company be forced to delay the recovery of these necessary environmental remediation costs. However, the mechanism by which UGI Gas will recover these costs does not permit UGI Gas to recover interest associated with such a delay in recovery. Therefore, Mr. LaTorre's proposal to delay the Company's recovery costs would unfairly frustrate the Company's ability to timely recover the full amount of these expenses. As shown at UGI Gas Exhibit VKR-2R, the Company will have total unrecovered environmental remediation costs of $6,361,000 by September 30, 2022 (the expected date at which the revised rates requested in this case would go into effect), of which $3,241,000 relates to spending prior to FY 2019. This is a substantial balance for the Company to carry without any carrying charge recovery on that balance.

Q. Are there any protections for ratepayers should the Company over-recover its environmental remediation costs?

A. Yes. The Company's balancing mechanism protects ratepayers in the event those costs are over-amortized due to the length of time between rate cases by creating a regulatory liability that the Company would need to pass back in a future case.

Q. Please summarize OCA witness Mr. Mugrace's adjustments to the Company's environmental remediation expense claim.

A. Similar to I&E witness Mr. LaTorre, OCA witness Mr. Mugrace recommends that the Company's under-recovered environmental remediation expense should be amortized over a 5-year period. OCA St. No. 1 at 37-38. Mr. Mugrace asserts that this amortization period is consistent with other environmental adjustments, and is appropriate given ongoing cash expenditures and the Company's annual rate case filings. OCA St. No. 1 at 37-38.

Q. Does the Company agree with Mr. Mugrace's proposal to amortize under-recovered environmental remediation expense over a 5-year period?

A. No. In addition to the reasons that the Company opposes I&E's proposed 5-year amortization period, Mr. Mugrace's additional arguments should also be rejected. As indicated above, the current 5-year amortization periods for the under-recoveries of costs in the period prior to FY 2019 and during FY 2019 are the results of agreements in prior cases and have no bearing on the correct amortization to apply in this proceeding for the FY 2020 and FY 2021 under-recoveries. The Company continues to incur expenditures for environmental remediation and, for each year since 2019, has spent more than it recovered in rates, thereby adding to its regulatory asset under-recovery each year. Further delay in recovery results in additional mismatch between the periods in which the costs incurred and the period of recovery. Given the Company's recent history of frequent rate case filings, it is most appropriate to allow the Company to recover these costs currently so that they are not a lingering issue for future rate proceedings. As indicated above, if the Company did over-recover, a regulatory liability would be established and any over-recovered amount would be refunded to ratepayers in a future rate proceeding.

Q. Does Mr. Mugrace propose an additional adjustment to the Company's claimed environmental remediation expense?

A. Yes. While Mr. Mugrace accepts the Company's five-year actual and projected spending for environmental remediation expense, he recommends that the Company use a five-year average instead of a three-year average to normalize its projected spending. OCA St. No. 1 at 15-16. Mr. Mugrace argues that this adjustment is necessary in order to be consistent with other environmental remediation expense adjustments. OCA St. No. 1 at 15-16. As such, he recommends a reduction of $43,733 in the Company's projected environmental remediation expense. OCA St. No. 1 at 16.

Q. Does the Company agree with this proposed adjustment?

A. No. As discussed above, the Company's environmental costs are fully reconcilable. Because they are reconcilable, it is illogical to attempt to minimize the amount of annual recovery. Mr. Mugrace fails to take into consideration that the other environmental adjustments relate to the period over which past under-recovered costs are recovered in rates. This calculation of a normalized annual recovery amount for future costs is an entirely different matter from the amortization of prior period costs and thus there is no logical reason that the periods used should be consistent.

B. OUTSIDE CONTRACTOR EXPENSES

Q. Do any of the parties propose an adjustment to the Company's expense claim associated with outside contractors?

A. Yes. OCA witness Mr. Mugrace recommends that the Company's outside contractors' expense amounts associated with Distribution Operations and Maintenance expense, Customer Accounts expense, and Administrative and General ("A&G") expenses be normalized using a 3-year period of 2020-2022. OCA St. No. 1 at 28-29 (proposing normalization adjustment for Distribution Operations and Maintenance expense), at 31-32 (proposing normalization adjustment for Customer Accounts expense), and at 48-49 (proposing normalization adjustment for A&G expense). Mr. Mugrace's proposal would decrease the Company's Distribution Operations and Maintenance expense by $2,114,000 (OCA St. No. 1 at 29; OCA Schedule DM-12), decrease the Company's Customer Accounts expense by $9,000 (OCA St. No. 1 at 32; OCA Schedule DM-13), and decrease the Company's A&G expense account by $23,000 (OCA St. No. 1 at 48-49; OCA Schedule DM-17).

Q. Does the Company agree with this adjustment?

A. No.

Q. Please explain why Mr. Mugrace's proposal to normalize outside contractors' expense over the 3-year period of 2020-2022 should be rejected.

A. The Company renegotiates its contracts with outside contractors approximately every three to four years. The 2020 and 2021 costs for outside contractors were based on pricing from the 2018 negotiation, while the FPFTY costs will be based on the pricing from the 2022 negotiation (this new pricing has become or will be effective in FY 2022). Therefore, it is not appropriate to use prior periods for outside contractor costs for the FPFTY, as these costs are based on entirely different and outdated contracts and the new contract costs are known and measurable. Based on these updated contracts, the Company has proposed an adjustment to increase its claim for outside contractor labor by $2,692,000, as discussed in the rebuttal testimony of UGI Gas witness Timothy J. Angstadt (UGI Gas St. No. 9-R). Mr. Angstadt also discusses the Company's contracting process and the recent contract renegotiation results at length within his rebuttal testimony.

Q. Is there any other reason that Mr. Mugrace's proposal to normalize outside contractors' expense should be rejected?

A. Mr. Mugrace's adjustment proposes a normalization period for outside contractor expenses using the years 2020 - 2022. As shown at UGI Gas Exhibit VKR-3R, the period that he selected for normalization of outside contractor expense results in the lowest amount of allowed expense of the three normalization periods available (2019 – 2021; 2020 – 2022 and 2021 – 2023). As also shown at UGI Gas Exhibit VKR-3R, at other places within his testimony, Mr. Mugrace selects different normalization periods, without explanation. As such, his method has the appearance of being wholly arbitrary. For this reason and the other reasons cited herein, Mr. Mugrace's adjustment to Outside Contractor Expenses should be rejected.

C. PENSION BENEFITS EXPENSE

Q. Do any of the other parties propose adjustments to the Company's claimed Pension Expense?

A. Yes. OCA witness Mr. Mugrace recommends "normalizing the pension expense over a three-year period 2019-2021." OCA St. No. 1 at 41. Mr. Mugrace argues that "[t]his adjustment reduces the cash contribution and the proposed adjustment from $8,388,000 to $2,429,133, a difference of $5,958,667." OCA St. No. 1 at 41; *see also* OCA Schedule DM-17.

Q. Does the Company agree with Mr. Mugrace's proposed adjustment?

A. No.

Q. Before explaining why the Company disagrees with this proposed adjustment, do you have any initial observations about Mr. Mugrace's proposal in light of the Company's actual cash contributions from FY 2019 through FY 2021?

A. Yes. I note that even if the Commission were to accept Mr. Mugrace's proposal to use a 3-year normalization period to adjust the Company's claim, if the Company's actual cash contributions (i.e., the basis for its claim) are normalized, it actually <u>increases</u> the

Company's claim from \$5.501 million to \$5.765 million. While I am not suggesting that normalization of the Company's actual cash contributions should be done in this case, and specifically explain below why normalization of pension expense based on prior period experience is not proper, I would only note that normalizing the Company's actual cash contributions over a 3-year period would <u>increase</u> its claim by \$0.264 million.

Q. Are there other reasons why you disagree with Mr. Mugrace's proposed adjustment?

A. Yes. Mr. Mugrace's adjustment to the Company's claimed pension expense should be rejected by the Commission for three additional reasons. First, Mr. Mugrace's adjustment results from an apparent misunderstanding of the basis for the Company's claim to recover pension <u>cost</u>, which is its cash contribution to the pension fund. Second, his adjustment is inconsistent with established ratemaking practice in Pennsylvania, which allows public utilities to claim expense based on the cash contribution to their pension funds. Third, Mr. Mugrace's proposed normalization period (*i.e.*, 2019-2021) is arbitrary and inconsistent with his proposed normalization periods regarding other categories of expenses (as shown at UGI Gas Exhibit VKR-3R).

Q. Please explain why it appears that Mr. Mugrace misunderstands the basis for the Company's claim.

A. The Company made its claim based on the portion of total plan cash contributions that related to UGI Gas. Mr. Mugrace's adjustment appears to be predicated on a normalized amount of the <u>difference</u> between GAAP pension expense (per the Company's budget) and pension cash contributions properly based on a recent actuarial report. If accepted, his adjustment would result in a claim which is based on neither GAAP expense nor cash contributions and is not connected to the Company's cost for providing pension benefits.

Q. Have you prepared an exhibit that helps to explain the basis for the Company's claim?

A. Yes. UGI Gas Exhibit VKR-4R shows how the Company calculated its claim. Within Schedule D-14 to Exhibit A – Revenue Requirement (Fully Projected) in the initial filing, the Company calculated an adjustment of $8,388,000 to adjust from the pension income in the budget of -$2,887,000 to the claimed cash contribution of $5,501,000. It may have been more clear had the Company shown two separate adjustments – the first to eliminate the $2,887,000 of income in the budget and the second to record the claimed cash contribution of $5,501,000. This two-adjustment methodology is shown at UGI Gas Exhibit VKR-4R. However, both methodologies result from using the same amount of the actuary-determined $5,501,000 cash contribution claim within the Company's revenue requirement claim.

Q. Why is it relevant that the Company's claim for pension cost is based on cash contribution, not on pension expense?

A. UGI Gas, consistent with other utilities within the state of Pennsylvania, has consistently based its pension cost on an actuary-determined cash contribution. If the Company were to change its method of recovery from period to period, it ultimately would not recover an appropriate amount of cost over the life of the pension plan. Therefore, Mr. Mugrace's recommendation to modify the Company's method of recovery should be rejected as inappropriate.

Q. Please comment on Mr. Mugrace's assertion that his recommended adjustment normalizes pension expense and reduces the cash contribution (OCA St. No. 1 at 41).

A. The Company's claim is based on the cash contributions that relate to UGI Gas. Mr. Mugrace normalizes the difference between cash and GAAP determined expense using historical figures. The Company's claim is based on current actuarially-determine cash contributions to the pension fund. Therefore, Mr. Mugrace's assertion that his recommendation normalizes pension expense is simply not based on up to date information or the full amount of the current cash contribution amount.

Mr. Mugrace's assertion that his recommended adjustment reduces the Company's cash contribution is also not true. The Company contributes to its pension plan based on the cash contribution as calculated annually by its third-party actuarial firm. If the Company accepted Mr. Mugrace's adjustment, its actual cash contribution would not change.

Q. You also testified that Mr. Mugrace's adjustment is inconsistent with established ratemaking practice in Pennsylvania. Please explain.

A. I am advised by counsel that, where a utility's claim to recover pension cost is based upon its actual cash contributions to the pension fund, it is generally inappropriate for those actual cash contributions to be normalized. It is my understanding that UGI Gas will further address this legal issue in its briefs.

Q. How is Mr. Mugrace's adjustment arbitrary and inconsistent with his other proposed adjustments that use a 3-year normalization period?

A. As shown at UGI Gas Exhibit VKR-3R, Mr. Mugrace selected different normalization periods for various adjustments. For the pension adjustment that he recommended, he selected a normalization period of 2019 – 2021, which results in the lowest possible claim of any potential selected three-year normalization period. The fact that Mr. Mugrace's selected period is inconsistent from adjustment to adjustment raises the question about whether his selected normalization period is arbitrary.

D. CORPORATE ALLOCATION OF ENVIRONMENTAL, SOCIAL AND GOVERNANCE ("ESG") COSTS AND COMPANY MEMBERSHIP COSTS

Q. Do any parties propose an adjustment to the Company's claim to recover certain costs incurred by UGI Corporation, which have been allocated to UGI Gas?

A. Yes. In addition to certain incentive compensation expenses allocated to UGI Gas (discussed below), OCA witness Mr. Mugrace identifies **[BEGIN CONFIDENTIAL]** $492,660 in costs at UGI Corporation (of which $115,094 is allocated to UGI Utilities, Inc. – Gas Division and included in the revenue requirement claim). These costs represent consulting costs and membership dues associated with Environmental, Social and Governance ("ESG"). **[END CONFIDENTIAL]**. Mr. Mugrace asserts these costs "do not support the safe, reliable and adequate service requirement of utility service but rather the costs are akin to sponsorships and civic related activities" and recommends that the costs be disallowed. OCA St. No. 1 at 51. Specifically, he claims that these costs are solely designed to maximize corporate profits for UGI Corporation's shareholders and advocating environmental goals. OCA St. No. 1 at 50-51.

Q. Does the Company agree with Mr. Mugrace's proposal to disallow these costs?

A. No.

Q. Please explain why not.

A. Initially, Mr. Mugrace's characterization that ESG costs are driving corporate profits at the expense of ratepayers is not grounded in evidence. His characterization is simply wrong. Also, I take issue with Mr. Mugrace claims that the Company's environmental stewardship activities are self-serving. Those efforts are important to the investor community, which secures the future success of this Company and enables the continued provision of safe and reliable service to customers by funding capital investment.

ESG is a "hot topic" in the investment community. Investors are interested in a Company's ESG strategy and often request this information prior to investing in a Company's stock. The New York Stock Exchange (on which the stock of UGI Corporation is traded) has developed an ESG Resource Center website for its members and investors. UGI Corporation has published three annual reports on ESG, and the most recent (2020) of which was rated at AA by rating agency MSCI ("Morgan Stanley Capital International"). UGI Corporation plans to issue its fourth ESG report in May 2022. In response to investor demand for ESG information, on March 21, 2022, the United States Securities and Exchange Commission ("SEC") proposed enhanced and standardized climate-related disclosures from its registrants. A portion of the $115,094 will be used to prepare for and/or comply with this SEC proposal. More specifically to Mr. Mugrace's proposal, a failure to align with shareholders' ESG expectations can lead to an increased cost of capital.

Q. How do the ratepayers of UGI Gas benefit from the ESG activities of UGI Corporation?

A. UGI Corporation's ESG activities are focused on environmental sustainability, social policies that promote diversity and inclusion, and governance of the Company to ensure that it has a clear purpose and strategic direction. While shareholders do benefit from these activities, ratepayers also benefit because strong policies in this area allow the Company to access capital markets to obtain the capital that is necessary to fund its replacement and betterment program (which leads to greater safety and reliability). ESG activities focus on the collection of needed environmental, social and governance data in an efficient manner, which limits the cost of this activity and lowers the overall expense passed along to ratepayers. Additionally, a focus on diversity and inclusion allows the Company to attract and retain quality employees who are essential to providing safe, efficient, and reliable natural gas service to ratepayers.

E. INCENTIVE COMPENSATION EXPENSE

Q. Do any of the other parties propose an adjustment to the Company's claim to recover the costs of certain of its incentive compensation plans?

A. Yes. OCA witness Mr. Mugrace proposes adjustments to several aspects of the Company's incentive compensation, which taken together would **[BEGIN CONFIDENTIAL]** decrease the Company's proposed total Incentive Compensation costs by $11,129,787 (*i.e.*, "the UGI Utilities portion of $4,916,000 and that which was allocated from UGI Corporation of $6,213,0000"). OCA St. No. 1 at 46. **[END CONFIDENTIAL]**

Q. Does the Company agree with Mr. Mugrace's proposed adjustment?

A. No. None of the reasons offered by Mr. Mugrace to disallow recovery of the Company's incentive compensation programs should be accepted. As explained below, the Company's incentive compensation is a component of its overall compensation program designed by management to offer a competitive package to attract and retain qualified employees. If the Company were to eliminate incentive compensation, it would need to increase another component of compensation in order to remain competitive in the employment market.

However, as an initial matter, I note that Mr. Mugrace appears to incorrectly assume that the Company's O&M expense claim includes incentive compensation costs associated with its UNITE Management Incentive Plan.

Q. Please explain.

A. Mr. Mugrace references documents provided in response to I&E discovery requests as CONFIDENTIAL Attachments I&E-RE-17.3 and I&E-RE-17.4, which describe the Company's UNITE Project Milestone Incentive Plan, and argues that the incentive compensation costs contemplated by this plan are not included in the incentive compensation expense costs shown in response to I&E-RE-17.2. OCA St. No. 1 at 44-45. **[BEGIN CONFIDENTIAL]** He subsequently recommends that the UNITE Management Incentive Plan budgeted amount of $2,603,000 be disallowed. **[END CONFIDENTIAL]**

However, the Company's expense claim in this case does not include any amounts associated with the UNITE Project Milestone Incentive Plan. Rather, these costs are capitalized and included in its rate base claim as part of the cost of the Asset Data Collection phase of the UNITE project. Within discovery request I&E-RE-17, I&E requested that the Company provide information about the actual expenses incurred for incentive compensation from FY 2019 – FY 2021, as well as claimed expenses by incentive type for FTY and the FPFTY. Within this same discovery request, I&E requested a copy of the UGI UNITE Incentive Compensation Plan. The Company provided responses to both of these requests. However, within the response at Attachment I&E-RE-17.1, the Company clearly indicated that the UNITE project bonuses were charged to capital and there were no expense dollars for FY 2019 – FY 2021 for this program. Additionally, the detail in Attachment I&E-RE-17.2 (which details the incentive compensation by program for the FTY and FPFTY expense claim) indicates no amounts labeled as "UNITE". Contrary to Mr. Mugrace's testimony, there are no expense amounts associated with the UNITE Project Milestone Incentive Plan and his understanding of the UGI Management Incentive Plan is simply incorrect. Therefore, his proposed disallowance of **[BEGIN CONFIDENTIAL]** $2,603,000 **[END CONFIDENTIAL]** should be rejected.

Q. For the sake of clarity, please provide a breakdown of UGI Gas's incentive compensation amounts that are included in its O&M expenses claim in this case.

A. Please see CONFIDENTIAL UGI Gas Exhibit VKR-5R for a detail of the incentive compensation amounts that are included in the Company's O&M expenses claim in this case. This detail agrees to a similar schedule provided as Attachment I&E-RE-17.2, as part of the discovery request process, with the following exceptions: (1) **[BEGIN CONFIDENTIAL]** $431,000 **[END CONFIDENTIAL]** of deferred compensation (under the Supplemental Executive Retirement Plan) is excluded from CONFIDENTIAL UGI Gas Exhibit VKR-5R because, upon further consideration, the Company does not believe that the amount associated with this plan is appropriately defined as incentive compensation. See further discussion of deferred compensation below; (2) $51,000 of incremental incentive bonus on the Compensation Benchmarking Adjustment (from Schedule D-9 within UGI Gas Exhibit A – Fully Projected) is added to CONFIDENTIAL UGI Gas Exhibit VKR-5R; and (3) addition of $38,000 of incentive bonus on TSA Security Directive Positions (from Schedule D-9 within UGI Gas Exhibit A – Fully Projected) is added to CONFIDENTIAL UGI Gas Exhibit VKR-5R.

1. UGI Corporation Allocation.

Q. Please summarize Mr. Mugrace's proposed disallowance of the Company's proposed total Incentive Compensation expenses associated with the Company's Corporate Allocation expenses.

A. As explained above, Mr. Mugrace proposes to disallow **[BEGIN CONFIDENTIAL]** $6,213,000 **[END CONFIDENTIAL]** in incentive compensation expense that was allocated to UGI Gas from UGI Corporation. OCA St. No. 1 at 47-48. Mr. Mugrace argues that "[t]here are a lot of variables for receipt of the incentive compensation and based upon the timing of the payout the costs are not known and measurable." OCA St. 1 at 48.

More specifically, Mr. Mugrace asserts that this amount should be disallowed because **[BEGIN CONFIDENTIAL]** the costs are associated with the UNITE ADC project and are to be paid out no later than April 30, 2023. OCA No. St. 1 at 47-48. He further claims that the costs are uncertain and speculative because they are budgeted at an expected 100% payout, despite the fact that payout amounts and timing are discretionary. OCA St. No. 1 at 47-48 **[END CONFIDENTIAL]**

Q. Does the Company agree with Mr. Mugrace's proposal to disallow these costs?

A. No, it does not.

Q. Please explain.

A. As described above, the UNITE bonus program document which Mr. Mugrace reviewed is in no way connected to the bonuses which are allocated to UGI Gas via the Corporate allocation. Therefore, Mr. Mugrace's arguments as it relates to this particular program are not relevant.

As shown at CONFIDENTIAL UGI Gas Exhibit VKR-5R, the actual costs allocated to UGI Gas for UGI Corporation incentive compensation include: (1) incentive compensation of **[BEGIN CONFIDENTIAL]** $2,185,000; **[END CONFIDENTIAL]** (2) stock options and restricted stock awards to employees of **[BEGIN CONFIDENTIAL]** $3,472,000; **[END CONFIDENTIAL]** and (3) **[BEGIN CONFIDENTIAL]** $555,000 **[END CONFIDENTIAL]** of equity compensation for directors.

The incentive compensation is awarded to UGI Corporation employees and executives based on performance under plans which establish financial and non-financial targets. For non-executive employees, the non-financial target is related to safety. For executives, the non-financial targets relate to safety and diversity. See copies of the fact sheets showing the plan criteria for the FY 2022 UGI Corporation plans at

CONFIDENTIAL UGI Gas Exhibit VKR-6R. Page 1 represents the non-executive plan and Page 2 represents the executive plan. Certain financial target amounts are redacted for confidentiality purposes.

Stock options and restricted stock awards are provided to employees based on employment agreements and/or based on management's discretion. The overall compensation policies and programs for executives are established by the Compensation and Management Development Committee of the Board of Directors of UGI Corporation. The program is designed to attract and retain talented and experienced executives and to reward them for leadership excellence.

Directors are provided with long-term equity awards in accordance with the director compensation program overseen by the Corporate Governance Committee and the Board of Directors as a whole. The Board of Directors uses market comparables to assess appropriate compensation for non-employee directors. Further details of the director compensation program can be found in the annual proxy statement of UGI Corporation, an excerpt of which is included at UGI Gas Exhibit VKR-7R.

The Company believes these plans are like in kind with executive and director compensation plans that the Commission has consistently allowed to be recovered in base rates for decades. Resulting from satisfying a combination of financial and non-financial targets, these plans have been determined to be necessary to retain and attract executives at the levels provided under the plans. Without the plans, and the incentives that they provide, the Company could lose the executives or be required to simply increase their base salaries to compensate for the loss of the plan. Similarly, UGI Corporation Directors are provided with competitive compensation to assure the appointment and retention of qualified Directors to help guide the Company.

2. UGI Gas Utility Incentive Compensation

Q. Please summarize Mr. Mugrace's proposed adjustments associated with UGI Gas's claimed incentive compensation costs incurred at the utility Company.

A. Mr. Mugrace begins by breaking down the incentive compensation costs associated with the compensation of UGI Gas employees and executives. OCA St. No. 1 at 46-47. He describes the (a) UGI Gas Management Incentive Plan ("MIP"), (b) Executive Bonus Plan, (c) Performance Restricted Stock Awards, (d) Stock Options, and (e) Supplemental Executive Retirement Plan ("SERP"), which comprise the Company's claimed incentive compensation costs of **[BEGIN CONFIDENTIAL]** $4,915,000. **[END CONFIDNETIAL]** OCA St. No. 1 at 46-47. A summary of claimed costs associated with each part of the Company's incentive compensation costs is set forth at CONFIDENTIAL UGI Gas Exhibit VKR-5R.

Mr. Mugrace recommends that the costs of each aspect of the Company's incentive compensation program be disallowed. OCA St. No. 1 at 47-48.

Q. Does the Company agree with Mr. Mugrace's proposed adjustment?

A. No, it does not. Below, I will explain why each aspect of the Company's incentive compensation program is properly recoverable. As an initial matter, however, Mr. Mugrace's attempt to evaluate individual aspects of the Company's incentive compensation program in isolation should be rejected.

Q. Why should the Commission reject Mr. Mugrace's attempt to evaluate individual aspects of the Company's incentive compensation program in isolation?

A. The Commission has previously rejected proposed adjustments to other utilities' claims for incentive compensation, including stock-based compensation. In PPL Electric Utilities Corp.'s ("PPL Electric") 2012 base rate proceeding, witnesses on behalf of I&E and the OCA recommended disallowance of half of PPL Electric's performance compensation expense claim, thereby requiring shareholders to share equally in the cost of its performance compensation plan. The Commission also rejected that proposal by stating:

> We find that, because PPL's incentive compensation plan is reasonable, prudently incurred, and is not excessive in amount, PPL is permitted full recovery of this expense. PPL correctly notes that many of the cases the OCA and I&E rely on are distinguishable from this case because, in those cases there was not adequate evidence that the incentive compensation expense was reasonable or that there was a benefit to ratepayers. Our decision to allow this incentive compensation expense is consistent with our prior decisions approving incentive compensation programs that are focused on improving operational effectiveness.

Pa. PUC v. PPL Electric Utilities Corp., Docket No. R-2012-2290597, at p. 26 (Final Order entered December 28, 2012) (internal citations omitted).

The Commission again made clear in the 2018 UGI Electric base rate proceeding that incentive compensation programs must be evaluated "as a whole," when determining whether the plan includes goals which benefit customers. *Pa. PUC, et al. v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, at p. 73-74 (Order entered Oct. 25, 2018). Breaking apart the Company's incentive compensation program into individual components inappropriately tries to single out individual aspects of the Company's total incentive compensation program, when, as a whole, the program clearly contains "both financial and operating metrics and goals which benefit customers," consistent with the Commission's order in 2018 UGI Electric base rate proceeding. *Id.*, at p. 74.

In addition, even assuming Mr. Mugrace's narrow view was proper, I disagree with his claim that the Company's ratepayers do not benefit from the achievement of the financial goals that comprise the Executive Bonus Plan, Performance Restricted Stock Awards, and Stock Options. The Company must have access to capital in order to invest in the infrastructure necessary to provide safe and reliable natural gas service to its ratepayers. The achievement of financial goals makes investment in the Company's stock an attractive option to investors, thereby allowing access to this necessary capital. Therefore, it is appropriate for ratepayers to bear the cost of these incentive compensation programs, just as they bear other costs of the Company from which they directly or indirectly benefit.

Finally, these programs also work in conjunction with other incentive compensation programs, as well as base compensation, to incentivize and retain its talented workforce. The Company's stock options and stock awards typically become exercisable three years after being awarded, and become void when an employee leaves the Company. Therefore, the stock options and stock award grants serve as an incentive to retain employees, thereby reducing transition costs. All else being equal, if the Company were to not offer these stock compensation awards, alternative incentive compensation or base compensation (e.g., salary) would be necessary to allow the Company to retain its workforce in a competitive job market.

Q. Do you have any further observations regarding why OCA's proposed adjustments regarding the Company's incentive compensation claim should be rejected?

A. Yes. Importantly, OCA witness Mr. Mugrace has not argued that UGI Gas's method of compensating its employees, as a whole, is unreasonable. Rather, the evidence of record demonstrates that UGI Gas attempts to compensate its employees consistent with industry standards and in a reasonable manner that permits the Company to attract and retain qualified employees, which is necessary in order to provide safe and reliable service to its customers. Mr. Mugrace's attempts to single out one specific aspect of the Company's overall compensation program—where the evidence otherwise demonstrates the overall program is reasonable—is improper and should be rejected.

Q. Please respond to Mr. Mugrace's assertion that the receipt and timing of the receipt of incentive compensation payouts are not known and measurable.

A. Mr. Mugrace proposes a test for the recovery of this expense that would be impossible to meet for any utility that seeks to recover projected incentive compensation expense for the FPFTY, because incentive compensation is paid out based upon the satisfaction of performance standards during the FPFTY. His proposal is not the test for the recovery of an expense and should be rejected.

Furthermore, regardless of Mr. Mugrace's assertion to the contrary, it is reasonably certain that the Company's incentive compensation program, as a whole, is necessary to attract and retain qualified employees. Adopting the test proposed by Mr. Mugrace would undermine UGI Gas's ability to attract and retain qualified employees, who are necessary in order to provide safe and reliable service to its customers.

a. UGI Gas MIP.

Q. Turning to the individual components of the Company's incentive compensation costs, please summarize Mr. Mugrace's proposed adjustment associated with the Company's MIP.

A. Mr. Mugrace proposes to disallow **[BEGIN CONFIDENTIAL]** $2,603,000 **[END CONFIDENTIAL]** in costs associated with the Company's MIP. OCA St. No. 1 at 47; OCA Schedule DM-17.

Q. Is Mr. Mugrace correct that the [BEGIN CONFIDENTIAL] $2,603,000 [END CONFIDENTIAL] that he proposes to be disallowed is solely associated with the "UNITE Management Incentive Plan Budget" as is suggested on page 47 of his testimony?

A. No. The UNITE incentive program is unrelated to the **[BEGIN CONFIDENTIAL]** $2,603,000 **[END CONFIDENTIAL]** for the Management Incentive Program. As explained above, the Company has no O&M expense claim associated with the UNITE incentive program.

Q. Please describe the Company's MIP.

A. The UGI Management Incentive Plan is an annual incentive program for which regular, full-time employees at career levels between M1 – M6 and between P2 – P5 are eligible (this includes most salaried employees that are below the executive level). The goals included in the plan span a wide range of areas, including financial performance, safety, reliability, customer satisfaction, business growth, sustainability, and capital deployment.

A copy of the FY 2022 plan document is provided CONFIDENTIAL UGI Gas Exhibit VKR-8R. Certain financial criteria have been redacted for heightened confidentiality purposes.

Q. Do the safety, reliability, customer satisfaction, business growth, sustainability, and capital deployment goals included in the MIP benefit ratepayers?

A. Yes. Ratepayers benefit directly when the Company provides safe and reliable natural gas service and when its customer service is responsive to customer needs. Additionally, business growth spreads the Company's costs over more customers, limiting the cost borne by each individual ratepayer. Ratepayers benefit from sustainability, as these efforts ensure that the Company is well positioned to be able to provide natural gas in the future, in an ecologically responsible manner. Finally, ratepayers benefit from capital deployment as this capital is deployed to replace aging infrastructure with more modern infrastructure, thereby increasing the safety and reliability of the Company's natural gas distribution system.

b. Executive Bonus Plan, Performance Restricted Stock Awards, Stock Options and SERP.

Q. Mr. Mugrace also recommends that the Commission disallow recovery of the Company's Executive Bonus Plan, Performance Restricted Stock Awards, Stock Options and SERP. OCA St. No. 1 at 48. Please summarize the basis for his recommended adjustment.

A. Mr. Mugrace recommends that the **[BEGIN CONFIDENTIAL]** $2,312,000 (*i.e.*, $714,000 + $766,000 + $401,000 + $431,000) **[END CONFIDENTIAL]** associated with each of these incentive compensation programs should be disallowed for two reasons. First, Mr. Mugrace asserts that "these are related to Executive Compensation currently employed by the Company and executives who have retired from the Company, and I believe that these costs do not provide benefits to customers in the area of customer service, customer satisfaction, customer engagement or safety and reliability issues." OCA St. No. 1 at 48. Second, he cites the Company's response to I&E-RE-18, and argues that "these costs are linked to future stock prices and stock price assumptions" and that he "do[es] not see any ratepayer benefit related to these [plans]." OCA St. 1 at No. 48.

Q. Does the Company agree with Mr. Mugrace's proposed disallowance?

A. No. Mr. Mugrace misunderstands how each of these programs benefits ratepayers and plays an essential role in the Company's ability to provide the compensation necessary to attract and retain qualified employees that provide safe, efficient and reliable natural gas service. In addition, as I previously stated in my testimony regarding Mr. Mugrace's improper attempts to single out specific aspects of the Company's overall compensation strategy for disallowance, there are additional specific reasons why it is reasonable and appropriate for the Company to recover the costs of the Executive Bonus Plan, Performance Restricted Stock Awards, Stock Options and SERP.

Q. Please describe the Company's Executive Bonus Plan.

A. The UGI Utilities Executive bonus plan applies to executives of the UGI Utilities business, and rewards these executives for meeting financial, safety and diversity goals. This plan is similar to the UGI Corporate Executive bonus plan described above, with the exception of the fact that this plan's financial goal is related specifically to the EBIT (Earnings Before Income Taxes) of UGI Utilities. See a copy of the fact sheet for this plan at CONFIDENTIAL UGI Gas Exhibit VKR-6R, page 3.

Q. Please explain how the non-financial performance metrics included in the Company's Executive Bonus Plan benefit the Company's ratepayers.

A. Ratepayers specifically benefit from the safety performance plan metric, as the provision of safe, reliable gas service is at the core of the UGI Utilities commitment to its ratepayers. The diversity initiative incentives the Company's leadership to consider diversity in its hiring practices, allowing the Company and its ratepayers to benefit from diverse viewpoints. This incentive is consistent with the Commission's "*Diversity at Major Jurisdictional Utility Companies—Statement of Policy*." *See* 52 Pa. Code §§ 69.801-69.809.

Q. Please describe the Company's Performance Restricted Stock Awards and Stock Options plans.

A. Similar to the equity compensation plans at UGI Corporation, restricted stock awards and stock options are awarded to key employees of UGI Utilities based on employment contracts and on management's discretion. Awards are granted to employees and typically have a vesting period of three years.

Q. How do the Company's Performance Restricted Stock Awards and Stock Options benefit ratepayers?

A. Stock awards and stock options benefit ratepayers by incentivizing key employees to maintain tenure with the Company through the vesting period. Equity compensation is a key component of compensation, particularly at the executive level. If the Company were to eliminate its equity compensation, it would need to increase base pay by at least the same amount in order to remain competitive in the employment market for talented executive-level employees. Ratepayers benefit from a stable group of Company executives who are motivated to advance the Company's mission.

Q. Please describe the Company's SERP.

A. The Company's SERP plan is designed to provide a retirement benefit for executive-level employees who are not eligible to receive the full typical Company contribution within its pension or 401(k) program. Current (not retired) executives who earn more than the cap for the regular pension or 401(k) plan are eligible for the SERP.

Q. Why should the Commission also reject Mr. Mugrace's recommended disallowance of the costs of the Company's SERP?

A. As indicated above, after further review of the specifics of the SERP plan, the Company does not believe that it is appropriately categorized as an "incentive" plan. As described above, it is designed to provide a normal level of retirement benefit and it has no goals or criteria to be met (as is typical for an incentive program). A SERP is a typical benefit of an executive benefit package, and the Company includes this benefit for its executives in order to be competitive for talent at that level. The SERP works together with other portions of the Company's pay and benefits program to provide a complete compensation package. If the SERP were excluded, the Company would need to increase base salary or other compensation in order to remain competitive for talented executives. The Company's SERP has existed for many years and has not previously been challenged in its rate proceedings.

Q. Does Mr. Mugrace recommend any other adjustments related to incentive compensation?

A. Yes, in addition to those adjustments discussed above, Mr. Mugrace recommends the following additional adjustments to eliminate the incentive compensation portion of certain compensation adjustments included in the Company's expense claim:

1. He recommends disallowance of the $38,000 incentive compensation portion of the Company's proposal to add 5 positions for TSA compliant directives be denied. OCA St. No. 1 at 26; and
2. He recommends disallowance of the $51,000 incentive compensation portion of the Company's Compensation Benchmark adjustment. OCA St. No. 1 at 24-25.

In both cases, Mr. Mugrace does not deny the Company's claim for the compensation adjustment. In fact, in the case of the TSA directive, he specifically states that he accepts the Company's proposal to add the 5 positions. However, he argues that the incentive compensation portion of these adjustments should be disallowed as he has not seen evidence of goals, performance matrices and objectives that need to be achieved before payout and also that it is too soon to determine if employees will achieve such goals. OCA St. No. 1 at 24-26.

Q. Does the Company agree with these proposed adjustments?

A. No. For both the Compensation Benchmark incentive compensation adjustment and the TSA directive incentive compensation adjustment, the related employees would be eligible for the MIP plan described above. As shown in CONFIDENTIAL UGI Gas Exhibit VKR-8R, the Company has clear performance goals and objectives for this plan. Of course, the Company cannot yet know the final outcome of the performance goals for the FY 2023 period, because the Company's case is based on a FPFTY. However, based on past performance, the Company believes that it is reasonable to assume that these goals will be achieved in order to earn a payout on the incentive compensation plan.

F. EMPLOYEE BENEFITS EXPENSE – MEDICAL AND DENTAL COSTS

Q. Do any of the other parties oppose the Company's claim to recover Employee Benefits expenses associated with medical and dental costs?

A. Yes. OCA witness Mr. Mugrace recommends that the Company's claim be reduced by $1,037,034, based upon his recommended reductions to employee headcount and his recommendation that medical and dental costs be normalized over a 3-year period from 2021-2023. OCA St. No. 1 at 50. Mr. Mugrace asserts that it is not reasonable for the Company to rely upon national surveys to project these costs, because national surveys are subject to interpretation and can result in changes based upon which provider prepares them. OCA St. No. 1 at 49. In addition, Mr. Mugrace argues that a post COVID-19 hybrid work environment may reduce employee costs because it can increase employee quality of life and provide "for less stressful day-to-day situations if carefully monitored." OCA St.

No. 1 at 49-50. He also believes that the Company has a marketplace where it may explore more affordable healthcare options. OCA St. No. 1 at 49-50.

Q. Does the Company agree with this proposed adjustment?

A. No. None of the reasons advanced by Mr. Mugrace demonstrates that his adjustment is reasonable or appropriate.

Q. Please respond to Mr. Mugrace's claim that it is not reasonable for the Company to rely upon national surveys to project medical and dental costs of its employees.

A. To clarify, the Company relied upon the analysis provided by its insurance broker, based on a national survey, but then tailored specifically to UGI's covered population (using geography and demographics). The broker indicated that the Pennsylvania healthcare costs tend to be overall in line with the national average, while healthcare costs in bordering states (such as New York, New Jersey, West Virginia and Ohio) are higher than the costs in Pennsylvania. The broker also indicated that UGI's population is slightly older than average, which was also factored into the specific increase that the broker recommended for UGI. UGI Gas's reliance on the analysis provided by its insurance broker is a normal business practice, and Mr. Mugrace provides no basis whatsoever to call into question the analysis of the broker.

Q. Should the Commission rely upon Mr. Mugrace's claim that a post COVID-19 hybrid work environment increases employee quality of life, which may allow the Company to explore more affordable healthcare options?

A. No. Mr. Mugrace was asked to provide any study, report, review evaluation or analysis of whether UGI Gas has switched to a hybrid workplace or reduced employee costs by switching to a hybrid workplace, and he indicated he had prepared no such studies in his response to UGI Gas-OCA-I-17. Similarly, Mr. Mugrace further indicated in his response to UGI Gas-OCA-I-17 that he has not prepared any study, report, review evaluation or analysis of the savings UGI Gas could gain by switching to a hybrid workplace, including savings related to his claim that the Company could refinance health care options. Essentially, Mr. Mugrace has offered no basis for his assertions. Therefore, they should be disregarded.

Q. Has the Company included any adjustment to its initial medical and dental costs within its rebuttal claim?

A. Yes. Based on the headcount adjustment that the Company has reflected within its rebuttal claim which reduces overall headcount by 17 positions (or 1%), the Company has reflected a similar 1% reduction to its medical and dental costs, which adjustment amounts to $95,065. See a calculation of this adjustment at UGI Gas Exhibit VKR-9R.

G. EMPLOYEE ACTIVITIES EXPENSE

Q. Do any of the other parties oppose the Company's claim for expenses related to Employee Activities?

A. Yes. I&E witness Mr. Walker recommends that the Company's claim be reduced by $370,291. I&E St. No. 1 at 6. He bases his adjustment on the FY 2019 expense, which inflates to the FPFTY using the average of Consumer Price Index ("CPI") inflation factors for FY 2022. I&E St. No. 1 at 6. Mr. Walker argues that it is "impossible" to know if employees will attend an optional Company picnic in 2023, as we are still in the midst of the COVID-19 pandemic. I&E St. No. 1 at 6. In addition, he asserts that, even if all employees attended, the $123 per employee cost is not prudent. I&E St. No. 1 at 6.

OCA witness Mr. Mugrace also proposes an adjustment to the Company's Employee Activities Expense claim. Mr. Mugrace asserts that the entire expensed amount of $588,226 should be disallowed. OCA St. No. 1 at 43. Mr. Mugrace argues that these expenses do not provide any benefits to ratepayers. OCA St. No. 1 at 43.

Q. Does the Company agree with either I&E's or OCA's proposed adjustments to its claim for Employee Activities expense?

A. No.

Q. Please explain why I&E witness Mr. Walker's proposed adjustment should be rejected.

A. In asserting his adjustment, Mr. Walker assumes that he knows how employees will respond to an opportunity to attend a Company picnic or other activities. He also indicates that a cost of $123 per employee is not "prudent".

As described within the testimony of Christopher R. Brown (UGI Gas Statement No. 1, page 27, line 14 through page 28, line 8), the Company has experienced an increase in voluntary turnover in a tight labor market. Given this situation and the overall tight labor market, the Company believes that it is prudent to spend a relatively modest amount of money on activities that can increase employee job satisfaction and thereby can increase employee retention. This investment is insignificant compared to the cost of recruiting and training a replacement employee.

Q. Why should the Commission reject OCA witness Mr. Mugrace's proposal to disallow the Company's claimed Employee Activities expense entirely?

A. The Company's proposed cost is for a reasonable level of normal employee activities designed to allow opportunities for employees to develop relationships with one another and to recognize service tenure. A reasonable calendar of activities designed to reward and incentivize employees is important to employee retention. As mentioned above, the Company has experienced an increase in voluntary turnover in a tight labor market. Given this situation, it would not be prudent for the Company to eliminate programs that contribute to the retention of qualified personnel who are responsible for the provision of safe, reliable natural gas service. When the Company experiences turnover, it loses valuable experience and then must invest time and money to recruit and train replacement employees. Therefore, the Company believes that its investment in a reasonable level of employee activities is worthwhile to create an environment conducive to employee satisfaction.

H. OSHA/ETS COMPLIANCE EXPENSE

Q. Do any of the other parties propose adjustments related to the Company's claim to recover costs associated with OSHA/ ETS compliance?

A. Both I&E and OCA propose adjustments to this aspect of the Company's claim.

Q. Has the Company already indicated that it will be withdrawing a portion of the costs originally included in this claim?

A. Yes. As noted by both I&E and OCA, the Company indicated in response to discovery request OCA-III-25 that it is withdrawing the majority of its initial claim because the Supreme Court of the United States overturned the federal vaccination and testing mandates for businesses that have over 100 employees. However, the Company is still claiming $52,934 of its already incurred costs and is requesting to amortize these costs over a one-year period. These costs were incurred by the Company to obtain legal advice related to complying with the mandate (in advance of the Supreme Court's decision), and to subscribe to a vaccine tracking software.

Q. Please explain I&E's proposed adjustment to the $52,934 in costs that the Company is continuing to claim associated with OSHA/ETS compliance.

A. I&E witness Mr. LaTorre accepts that these COVID-19 related costs were already incurred by the Company, but recommends that the Company's claim to recover these costs be amortized over a 20-month period, which he asserts is consistent with his proposed rate case filing frequency used to calculated rate case expense. I&E St. No. 3 at 14-15. His proposal would reduce the Company's claim by $21,174.

Q. Does the Company agree with I&E's proposed adjustment based upon the use of a 20-month amortization period?

A. No. This adjustment is proposed by I&E based upon its use of a 20-month period to normalize the Company's rate case expense. UGI Gas witness Ms. Hazenstab addresses and refutes I&E's proposed rate case expense adjustment in her rebuttal testimony (UGI Gas St. No. 2-R). I&E's proposed adjustment to OSHA/ETS compliance costs should be rejected for the same reasons.

Q. Please explain OCA's proposed adjustment to the $52,934 in costs that the Company is continuing to claim associated with OSHA/ETS compliance.

A. OCA recommends that all of these costs be disallowed. OCA St. No. 1 at 39-40. OCA witness Mr. Mugrace asserts that because "the Federal Mandate has not passed, these legal costs are moot, and ratepayers should not be required to absorb these costs." OCA St. No. 1 at 40.

Q. Does the Company agree with OCA's proposal to disallow these costs?

A. No. I am advised by counsel that the test for whether costs are recoverable is evaluating whether they were reasonably and prudently incurred at the time they were incurred, not whether the costs are deemed "moot" based on facts and circumstances that developed after the costs were incurred. The Company sought legal advice on a rather unusual legal issue and obtained software in an attempt to comply with an imminently applicable federal law. While hindsight regarding the fact that the mandate was ultimately overturned may be 20/20, these costs were reasonably and prudently incurred at the time they were incurred and should be recovered.

I. ADVERTISING EXPENSE

Q. Do any of the other parties propose adjustments to the Company's claimed advertising expense in this case?

A. Yes. I&E witness Mr. Walker and OCA witness Mr. Mugrace each oppose the Company's claimed amounts associated with "Other Advertising Programs." I&E St. No. 1 at 12-13; OCA St. No. 1 at 36. In addition, Mr. Mugrace also opposes the Company's claimed amount for "Conservation Advertising." OCA St. No. 1 at 35-36.

Q. Please summarize I&E's and OCA's recommended adjustments to the costs claimed for Other Advertising Programs.

A. Both I&E witness Mr. Walker and OCA witness Mr. Mugrace recommend that the claimed $885,178 associated with Other Advertising Programs be disallowed. I&E St. No. 1 at 12-13; OCA St. No. 1 at 35-36. Mr. Walker asserts that the Other Advertising Programs only promote the Company's image and not the benefits of domestic natural gas. He cites several examples of sponsorships undertaken by the Company. I&E St. No. 1 at 12-13; I&E Exhibit No. 1, Schedule 5. OCA similarly asserts these costs are not related to institutional or instructional advertising that benefits customers, but are associated with the Company's branding, recognition and role as a good corporate citizen. OCA St. No. 1 at 35-36.

Q. Does the Company agree with I&E's and OCA's recommendation that the Commission disallow recovery of the costs associated with the Company's Other Advertising Programs?

A. No. Other Advertising Programs consist primarily of costs for sponsorships, building meetings / trade shows, and branded promotional items. While the examples provided by the Company and included as I&E Exhibit No. 1, Schedule 5 demonstrate only the appearance of the Company's logo on sponsored event signage, they are not able to pictorially convey the opportunities that are afforded to Company personnel by virtue of sponsoring events. Event sponsorship typically comes with tickets to the related event, which allows Company personnel to attend. Attending such events allows the Company to raise awareness of natural gas as an option, and to develop relationships and discuss the benefits of natural gas with other attendees.

These sponsorships are key to attracting additional customers and these additional customers reduce the overall revenue requirement that is borne by each individual customer.

Q. Please summarize OCA's recommended adjustment to the costs claimed for Conservation Advertising.

A. OCA witness Mr. Mugrace proposes to normalize these costs over the 3-year period of 2020-2022, which would reduce the Company's claim by $193,114. OCA St. No. 1 at 36. Mr. Mugrace asserts that normalization is appropriate because "[t]he Company did not record any costs to this account in FY 2019," "the costs incurred in FY 2020 and FY 2021 reflect a normal level of costs for this category" and "[t]he Company has not justified the 70% increase over the FY 2022 and FY 2023 balance." OCA St. No. 1 at 36.

Q. Do you agree with Mr. Mugrace's proposed reduction to the Company's claimed Conservation Advertising expense?

A. No.

Q. As an initial matter, is Mr. Mugrace correct that the Company did not record any costs to this account in FY 2019?

A. No. As shown at Attachment OCA-III-25 (within Book I in the Company's initial filing), the Company spent $603,642 on Conservation of Energy advertising in FY 2019.

Q. Please respond to his assertion that the costs incurred in FY 2020 and FY 2021 reflect a normal level of costs for this expense category.

A. The Company's advertising program for FY 2020 was impacted by the COVID-19 pandemic, as the Company almost completely eliminated its advertising in the third and fourth quarters of FY 2020 (March – September 2020) due to the uncertainty introduced by the pandemic. The Company's spending continued to be curtailed in FY 2021. Therefore, FY 2020 and FY 2021 are not reflective of a normal level of costs for conservation advertising.

Q. Please explain why the Company's claimed costs for FY 2022 and FY 2023 are justified.

A. As indicated in response to I&E-RE-31, the Company is resuming normal activities in print and digital channel advertising related to conservation-related efforts, which help customers reduce energy consumption.

Q. Are there any further reasons why the Commission should reject Mr. Mugrace's proposal to use a 3-year normalization period of 2020-2022 with respect to Conservation Advertising?

A. Yes. As indicated above in response to previous adjustments, Mr. Mugrace appears to be cherry-picking normalization periods to minimize the Company's allowed claim. As shown at UGI Gas Exhibit VKR-3R, Mr. Mugrace selected different periods for different adjustments. In the case of conservation advertising, the period selected included the year that was most impacted by the COVID-19 pandemic (2020), but excluded the prior year when conservation advertising costs were higher (2019).

J. SPONSORSHIPS EXPENSE

Q. Did any of the parties propose an adjustment regarding the Company's proposed Sponsorships expense?

A. Yes. OCA witness Mr. Mugrace recommended the Company's sponsorship costs associated with Coats for Kids, American Red Cross, Sound the Alarm, Honor Roll, United Way Day of Caring and other social programs be disallowed. OCA St. 1 at 43-44. Mr. Mugrace argued that these costs do not benefit ratepayers, and mainly benefit the Company by contributing to its good corporate citizenship. OCA St. 1 at 44. Mr. Mugrace's recommendation would reduce the Company's expense claim by $424,000. OCA St. 1 at 44; OCA Schedule DM-17.

Q. Does the Company agree with Mr. Mugrace's recommendation that the costs associated with the Company's Sponsorship and participation in programs such as Coats for Kids, American Red Cross, Sound the Alarm, Honor Roll, United Way Day of Caring be disallowed?

A. No, it does not.

Q. Please explain why the Commission should reject Mr. Mugrace's adjustment.

A. Sponsorship programs such as those described above, are essential to maintaining ties in the communities where the Company provides service. These opportunities ensure that the Company's potential customer base remains aware of the Company and the services it provides, and they serve as an attraction for potential customers and potential employees.

Additionally, this adjustment proposed by Mr. Mugrace is duplicative of his adjustment related to Other Advertising Programs discussed in section I above. Mr. Mugrace recommended the Other Advertising Programs adjustment based on information provided by the Company in Attachment III-A-25 (within Book I to the original filing), which provides details of expenditures for advertising by major media and by certain categories of advertising as required for this standard filing requirement. Within this schedule, sponsorships are included within the Other Advertising Programs category. This schedule provides details of all advertising, which includes amounts in several different FERC accounts.

Separately, the Company provided a detail of Miscellaneous General Expenses (which is FERC account 930.2) at Attachment III-A-28.1 in response to a separate standard filing. Of the sponsorship advertising summarized in Attachment III-A-25, $389,774 is included within FERC account 930.2. Therefore, this portion of Mr. Mugrace's adjustment should be rejected solely because it is duplicative of his earlier adjustment to Other Advertising Programs.

K. MEMBERSHIP DUES EXPENSE

Q. Do any of the other parties oppose the Company's claim for recovery of certain membership dues?

A. Yes. I&E witness Mr. Walker proposes to disallow $153,998 in membership dues from the Company's claim, which he asserts are related to membership in organizations that are not necessary to the Company's provision of safe and reliable gas service. I&E St. No. 1 at 14-15. OCA witness Mr. Mugrace similarly proposes to disallow $540,192 in membership dues from the Company's claim, which he also asserts are related to membership in organizations that are not necessary to the Company's provision of safe and reliable gas service. OCA St. No. 1 at 42-43.

Q. Before you respond to these proposed adjustments, do you have any clarifications of information previously provided regarding Company Memberships at Attachment SDR-RR-30 (which provided Memberships by organization for the FPFTY) and at Attachment I&E-RE-20(A) (which provided Memberships by organization for 2019 – 2022)?

A. Yes. One of the organizations on both of these listings was identified as Cyber Resilient Energy Delivery Consortium, but should have been identified as Capital Region Economic Development Company (both organizations share the acronym of "CREDC", and Company personnel initially misinterpreted these identical acronyms). The amount included in the FPFTY claim for this membership is $30,480. Because this is an organization similar to other economic development organizations opposed by I&E witness Mr. Walker, the Company will assume that this $30,480 amount is also disallowed by I&E witness Mr. Walker, and will respond to his proposed adjustment as if it were a total of $184,478 ($153,998 + $30,480). OCA witness Mr. Mugrace disallowed this membership, and the Company will assume that he continues to do so with the clarified identification.

Q. Please identify and describe the membership dues that both I&E and OCA propose to disallow, and the additional membership dues that only OCA proposes to disallow.

A. The following table indicates the membership dues that are opposed by I&E and by OCA. Note that OCA opposes all memberships that are listed in this table, while I&E opposes only those in the first section of this table:

Membership Costs Denied by I&E Witness Mr. Walker:	
Allentown Economic Development Corporation	$ 5,148
Capital Region Economic Development Company	30,480
Economic Development Company of Lancaster County	32,964
Lebanon Valley Economic Development Corporation	8,244
Lehigh Valley Economic Development Corporation	21,636
Northeastern Pennsylvania Alliance	1,704
Penn's Northeast	5,664
Pennsylvania Chamber of Business & Industry	66,521
Pennsylvania Economy League	12,117
Total Opposed by I&E	$ 184,478
Additional Membership Costs Denied by OCA Witness Mr. Mugrace:	
Association for Material Protection and Performance	1,932
Energy Association of Pennsylvania	145,058
Energy Solutions Center	6,225
Focus Central Pennsylvania	3,096
Natural Gas Supply Collaborative	20,000
Natural Gas Vehicles of America	26,753
Society of Gas Operators	1,863
The Coalition for Renewable Natural Gas	29,000
Other Organizations under $1,500	11,724
Total Opposed by OCA	$ 430,129

Q. Does the Company agree with the adjustments proposed by I&E and OCA?

A. No.

Q. Please explain why it is appropriate for the Company to recover its membership dues associated with the above referenced organizations opposed by both I&E and OCA.

A. The membership fees opposed by I&E witness Mr. Walker are related to economic development corporations, the PA Chamber of Business & Industry, and the PA Economy League. The Company's membership in these organizations allows it to grow its customer base, primarily by attracting new industrial and commercial customers. These organizations work primarily with large commercial companies who are making site selections, and the Company's active involvement in these organizations allows it to proactively work with these targets, promoting the benefits of natural gas for their energy needs and encouraging them to select sites that are located in close proximity to existing gas mains. Without membership and active involvement in these organizations, the Company would experience less commercial growth, resulting in higher costs passed along to ratepayers (including its residential customers).

Q. Please explain why it is appropriate for the Company to recover its membership dues associated with above referenced organizations opposed only by OCA.

A. These organizations have a variety of purposes, including the promotion of safe operating practices, advocating for renewable natural gas resources, growing the use of natural gas, and the sharing of information among utilities. UGI Gas's membership in these organizations allows the Company to benefit from the resources provided by these various organizations, receiving information about safety and reliability, as well as growth within natural gas and renewables, all of which benefit ratepayers.

The following contains information about the purpose of each individually listed organization, as provided on the organization's website and an explanation of how participation benefits ratepayers:

1) Association for Material Protection and Performance ("AMPP") – AMPP represents the largest global community of corrosion and protective coatings professionals. Its members are dedicated to advancing technical and practical expertise in corrosion prevention and control. AMPP provides members with the knowledge and resources to ensure high performance materials are used to build and maintain sustainable infrastructure.
   a. The Company's membership in AMPP benefits ratepayers and furthers the provision of safe and reliable service because the Company learns about techniques to prevent pipe corrosion, thereby making its distribution system safer.
2) Energy Association of Pennsylvania ("EAP") – EAP is well-established as the voice of Pennsylvania's electric and natural gas utilities. EAP helps its members better serve their customers by acting as a clearinghouse for information on best practices within the industries. The Association also serves an educational function by sponsoring conferences emphasizing safety topics on electric and natural gas operations and consumer service issues that are attended by employees of member companies, out-of-state utilities, and government agencies.

a. The Company's membership in EAP benefits ratepayers because the Company learns about best practices in utility customer service and safety, which influence its own practices, policies and procedures.

3) Energy Solutions Center ("ESC") – ESC promotes the deployment of energy efficient natural gas solutions by developing innovative partnerships between energy utilities, equipment vendors and manufacturers, and energy customers.

a. The Company's membership in ESC benefits ratepayers because the Company gathers information about energy efficiency, which it is able to pass along to ratepayers to assist them in conserving energy.

4) Focus Central Pennsylvania – Focus Central Pennsylvania provides a centralized location for current information on available properties, market data, labor data and much more.

a. The Company's membership in Focus Central Pennsylvania benefits ratepayers because the Company is able to obtain market information for its service territory, allowing it to benchmark its labor standards and also to be informed about available properties, which might lead to future development opportunities. These opportunities for growth ultimately reduce the cost borne by each individual ratepayer.

5) Natural Gas Supply Collaborative ("NGSC") – NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for natural gas supply.

a. The Company's membership in NGSC benefits ratepayers because it informs the Company about best practices in safe natural gas supply.

6) Natural Gas Vehicles of America – Natural Gas Vehicles of America's purpose is to create a profitable, sustainable and growing market for compressed natural gas (CNG) and liquefied natural gas (LNG)-powered vehicles.
   a. The Company's membership in Natural Gas Vehicles of America benefits ratepayers because it allows the Company to explore options for expanding the use of natural gas for powering vehicles, leading to growth opportunities which ultimately reduce the cost borne by each individual ratepayer.
7) Society of Gas Operators – The Society of Gas Operators is an Industry group focusing on the sharing of information and topics relevant to Gas Operations. Membership is predominantly from gas companies and suppliers in the North East United States.
   a. The Company's membership in the Society of Gas Operators benefits ratepayers because it allows the Company to learn about best practices in gas operations from its peers in the same geographic region.
8) Coalition for Renewable Natural Gas ("RNG Coalition") – RNG Coalition advocates for sustainable development, deployment and utilization of renewable natural gas so that present and future generations will have access to domestic, renewable, clean fuel and energy.
   a. The Company's membership in the RNG Coalition benefits ratepayers because it informs the Company about renewable natural gas options, allowing natural gas to remain a sustainable option for many future years.

Q. Are there any further reasons why the Commission should specifically reject Mr. Mugrace's proposed reduction of $540,912 to this expense category?

A. Yes. Mr. Mugrace's calculation of his proposed adjustment is not sound. He specifically indicates that he is allowing the (1) American Gas Association - $621,015 (less $23,599 related to Lobbying) and (2) Northeast Gas Association - $55,000 for a total of $652,416. The Company's claim is for $1,082,546. The claim amount is based on the information in the Company's original filing at Attachment SDR-RR-30, which shows a total membership cost of $1,115,404, but indicates within footnotes that $32,858 is related to lobbying costs and is excluded from the Company's claim ($23,599 for American Gas Association and $9,259 for Energy Association of Pennsylvania). Therefore, Mr. Mugrace's adjustment should have been for $430,130 ($1,082,546 total Company claim less $652,416 allowed by Mr. Mugrace for American Gas Association and Northeast Gas Association).

L. DEPRECIATION EXPENSE

Q. Do any of the other parties propose an adjustment to the Company's claimed depreciation expense?

A. Yes. I&E witness Mr. Sakaya recommends that the Company's claimed depreciation expense be decreased by $3,666,000, based upon I&E's proposed adjustments to utility plant in service at the end of the FTY and FPFTY. I&E St. No. 5 at 16. OCA witness Mr. Mugrace similarly recommends that the Company's claimed depreciation expense be decreased by $4,517,363 associated with OCA's proposed adjustments to utility plant in service.[3]

Q. Does the Company agree with either I&E's or OCA's proposed adjustment to depreciation expense?

A. No. The Company disagrees with these adjustments, which are derivative of I&E's and OCA's proposed adjustment to the Company's utility plant in service claim. The proposed utility plant in service adjustments should be rejected for the reasons explained in UGI Gas witness Ms. Schappell's rebuttal testimony (UGI Gas St. No. 5-R).

Q. Does the Company have an update to its claimed for depreciation expense based upon its proposed adjustment to plant in service?

A. Yes. The Company has reduced its claim for depreciation expense upon identifying certain assets that were incorrectly included in or excluded from plant in service in the claim, as discussed in the rebuttal testimony of UGI Gas witness Vicky A. Schappell (UGI Gas St. No. 5-R). This results in a reduction to depreciation expense of $18,000. In addition, the Company identified (1) that certain allocations were mistakenly excluded from its rate claim, which results in a further reduction of depreciation expense of $524,000, and (2) that depreciation was claimed for a certain asset at an inappropriate rate, indicated within my response to discovery request I&E-RE-42, which results in a further reduction of depreciation expense of $231,000. These depreciation expense adjustments collectively result in a decrease to operating expense of $773,000. *See* UGI Gas Exhibit VKR-1R.

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[3] Mr. Mugrace specifically accepts the Company's proposed service lives and depreciation rates. OCA St. No. 1 at 52.

V. UNCOLLECTIBLES ACCOUNTS EXPENSE

Q. Do any of the other parties oppose the Company's proposal to continue to defer COVID-19 related incremental uncollectibles expense?

A. Yes. I&E witness Mr. Walker disagrees with the Company's proposal to continue tracking incremental uncollectibles expense related to COVID-19 in future years. I&E St. No. 1 at 9-10. Mr. Walker argues that COVID-related uncollectibles are included in the Company's forward-looking routine uncollectibles expense, and that continued deferral past the effective date of new rates established in this case would result in redundant recovery. I&E St. No. 1 at 11. He further argues that in the settlement approved by the 2020 Base Rate Case Order the Company agreed to not continue accumulating COVID-19 related costs beyond the effective date of new rates established in this proceeding. I&E St. No. 1 at 11.

Q. Does the Company agree with Mr. Walker's proposal?

A. No.

Q. Please respond to his claim that continued deferral of incremental uncollectibles expense would result in redundant recovery.

A. The Company would not continue to recover incremental uncollectible expense above the existing $12.81 million cap after the implementation of its new rates. Rather, the Company believes that it is appropriate to defer for future recovery costs in excess of the uncollectible accounts amount ultimately approved in its new rates. This methodology would not result in redundant recovery because this expense in excess of the amount approved for base rate recovery would be recovered only once (within the amount deferred).

Q. Please respond to Mr. Walker's claim that in the settlement approved by the 2020 Base Rate Case Order, the Company agreed to not continue accumulating COVID-19 related costs beyond the effective date of new rates established in this proceeding.

A. The Company's proposal is not inconsistent with the settlement language, contrary to Mr. Walker's claim. The Company did not relinquish its right to request an extension of the period referenced in Mr. Walker's testimony. Importantly, and consistent with the Commission's March 13, 2020 Emergency Order at Docket No. M-2020-3019244, Secretarial Letter dated May 13, 2020 and the Commission's October 8, 2020 Order, the Company had in place a moratorium on all terminations through October 2020 and restrictions on certain terminations through April 1, 2021. The Company also offered extended payment arrangements to customers through September 30, 2021 at the direction of the Commission that extend up to 5 years. The Company has continued to experience higher than normal delinquency rates on the COVID related payment arrangements as shown in the responses to discovery requests OCA-II-40 and OCA-II-41, which are respectively attached to my testimony as UGI Gas Exhibits VKR-10R and 11R. The customers on these arrangements continue to carry balances that are higher than they were prior to the Commission's March 13, 2020 Emergency Order. Additionally, the increase in the commodity cost of gas driven by current inflationary factors will likely cause the Company to incur additional incremental expenses above those embedded in rates.

Q. Please explain how the Company plans to defer and amortize incremental uncollectible costs.

A. As agreed to in the settlement approved by the 2020 Base Rate Case Order, the Company will amortize the regulatory asset balance of $1.503 million for uncollectibles that accrued prior to October 1, 2021 over the 10-year period beginning with the effective date of rates established in this proceeding, for purposes of accounting and future ratemaking. In addition, also pursuant to the settlement approved by the 2020 Base Rate Case Order, the Company will defer as a regulatory asset balance the amount that accrues for uncollectibles (above the $12.8 million built into current rates) beginning October 1, 2021 and ending September 30, 2022 (FY 2022). Furthermore, the Company will amortize this FY 2022 regulatory asset over the 10-year period beginning with the effective date of rates established in the Company's next base rate proceeding for purposes of accounting and future ratemaking,

Q. Is the Company proposing any further regulatory asset treatment to uncollectible accounts expense as a part of its rebuttal case?

A. Yes. Due to the increase in the commodity cost of gas driven by current inflationary factors, the Company proposes to defer any annual uncollectible accounts expense in excess of $18.0 million (or such amount that is built into its rate as approved by the Commission as part of this proceeding) beginning with the fiscal year beginning October 1, 2022 and ending September 30, 2023 (FY 2023) and continuing for annual periods thereafter until the effective date of the Company's next base rate filing. The Company further proposes that it be permitted to recover for ratemaking purposes such deferred amounts in the Company's next general rate proceeding over an amortization period of 3 years, without interest.

Q. What is the basis for the $18.0 million?

A. The $18.0 million represents the uncollectible accounts expense built into the Company's rate claim within its rebuttal case. See Schedule D-1, Uncollectible Expense, line 11 of UGI Gas Exhibit A (REBUTTAL), which is sponsored by UGI Gas witness Ms. Tracy A. Hazenstab as a part of her rebuttal testimony (UGI Gas St. No. 2-R). This amount will be adjusted to reflect the amount of uncollectible accounts expense built into the Company's final rates as approved by the Commission as part of this proceeding.

Q. What has been the level of increase in the Purchase Gas Cost rate since September 30, 2021?

A. The Purchase Gas Cost rate is 22.4% percent higher than it was at September 30, 2021, and the Company anticipates that the rate will continue to increase into the foreseeable future.

VI. MISCELLANEOUS

Q. **Is the Company making any changes to its allocation of reconnections fees included in its miscellaneous revenues?**

A. Yes. UGI Gas witness Ms. Heppenstall (UGI Gas St. No. 10-R) explains that the Company is updating its allocation by rate class for reconnection fees as of the 12-months ending January 31, 2022, in accordance with the Company's response to OCA-I-42, which I prepared. Ms. Heppenstall's rebuttal details the specific reconnection fees revenues and how they are being allocated pursuant to Attachment OCA-I-42, which appears as UGI Gas Exhibit CEH-1R.

VII. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 5-R

Rebuttal Testimony of
Vicky A. Schappell

Topics Addressed: **Responses To Adjustments To Utility Plant In Service**

Dated: May 17, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vicky A. Schappell. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 5, on January 28, 2022.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the following direct testimony submitted by the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"): I&E Statement No. 5, the direct testimony of Esyan A. Sakaya; and OCA Statement No. 1, the direct testimony of Dante Mugrace.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Gas Exhibits VAS-1R through VAS-4R. UGI Gas Exhibit VAS-1R is CONFIDENTIAL.

II. UTILITY PLANT IN SERVICE

Q. Did any parties propose adjustments to the Company's claimed utility plant in service in their direct testimony?

A. Yes. OCA witness Mr. Dante Mugrace and I&E witness Mr. Esyan A. Sakaya both recommended adjustments to the Company's claimed plant in service for the future test year ending September 30, 2022 ("FTY") and the fully projected future test year ending September 30, 2023 ("FPFTY").

A. OCA WITNESS MUGRACE PLANT IN SERVICE ADJUSTMENT

Q. Mr. Mugrace claims that certain capital projects budgeted for the FTY and FPFTY, as listed on pages 8-9 of OCA St. No. 1, should be disallowed. Do you agree?

A. No. OCA witness Mr. Mugrace recommends that certain capital projects budgeted during the FTY and the FPFTY be eliminated from the Company's claim as noted in his testimony. OCA St. No. 1 at 9. Mr. Mugrace asserts that the projects he recommends be eliminated from the FTY and FPFTY will not be completed and placed into service until after the end of the FPFTY. OCA St. No. 1 at 7-9. As support for his adjustment, Mr. Mugrace cites the Company's response to I&E-RB-4-D, which shows the Company's plant in service budgeted by account for the FTY and FPFTY, as well as all projects to be placed into service during these periods (with estimated in service dates). OCA St. No. 1 at 7. He then asserts that the confidential response to this discovery request "shows that for a number of projects the estimated completion date will be beyond the FPFTY period ending December 31, 2023." OCA St. No. 1 at 7. Mr. Mugrace next lists the projects included in the Fiscal Year ("FY") 2022 budget (i.e., the FTY) and the projects included in the FY 2023 budget (i.e., the FPFTY) that he claims will be placed into service beyond the end of the FPFTY.

OCA St. No. 1 at 8-9. Based on this assertion, he recommends the removal of these projects from the Company's claimed plant in service totaling $85,681,967 (a decrease for the FTY of $27,785,189 and decrease for the FPFTY of $57,896,778).

Q. Does the Company agree with Mr. Mugrace's proposed adjustment to decrease its FTY and FPFTY plant in service balances?

A. No, it does not agree.

Q. Is Mr. Mugrace correct that the Company's FPFTY is the "period ending December 31, 2023" (OCA St. No. 1 at 7)?

A. No, he is not. The Company's FPFTY is the fiscal year ending September 30, 2023.

Q. Is Mr. Mugrace correct that the projects listed on pages 8-9 of his direct testimony will be placed into service after the end of the FPFTY?

A. In large part, yes. However, Mr. Mugrace misunderstands the Company's response to I&E-RB-4-D and how nearly all of these budgeted projects for FY 2022 and FY 2023 were already excluded from the projected plant in service for the FTY and the FPFTY. Thus, $84,981,121 of Mr. Mugrace's proposed exclusion of $85,681,967 in capital additions is not appropriate as they were *never included in the Company's filed claim*.

Q. Have you prepared an exhibit that depicts how projects identified by Mr. Mugrace were already accounted for by the Company, and therefore not included in its claimed plant in service?

A. Yes. Attached to my testimony is CONFIDENTIAL UGI Gas Exhibit VAS-1R. The exhibit shows the specific budgeted spending projects that were excluded from the total plant in service claimed in the case. CONFIDENTIAL UGI Gas Exhibit VAS-1R shows that total plant in service was already reduced by $84,981,121 because those projects are scheduled to be placed into service post-FPFTY.

Q. Did the Company also provide a discovery response explaining that the projects identified by Mr. Mugrace for disallowance were not included in the Company's claim?

A. Yes. Originally, the Company served discovery response I&E-RB-4-D on the parties on February 28, 2022. That response provided construction budget amounts by account for the FTY and FPFTY along with estimated project completion dates. The response then rolled forward the spending to include the total plant in service additions for both the FTY and FPFTY. The in-service adjustments in Attachment I&E-RB-4 included the open construction work in progress ("CWIP") that was expected to go into service during the FTY and FPFTY along with excluding the projects that were not expected to be in service by the end of the FPFTY.

Q. After reviewing Mr. Mugrace's direct testimony, how did the Company address the remaining small amount of plant in service adjustments ($700,846) which were warranted?

A. On May 4, 2022, the Company submitted I&E-RB-4-D (Supplemental Response) to show these adjustments. Specifically, the Company proposed to reduce the FTY total plant in service by $700,846 as the Company inadvertently included these post-FPFTY projects.

Q. Did I&E-RB-4-D (Supplemental Response) include any other corrections?

A. Yes. The Company also added two projects which were inadvertently excluded from the FPFTY claim. These two projects total $29,961. Also, the Company corrected the in-service date for one project.

Q. What is the impact of the Company's correction to the FY 2022 and FY 2023 plant in service balances on its claimed rate base in this proceeding?

A. The Company's correction decreases rate base by $670,885. The corresponding depreciation adjustment is included in UGI Gas Exhibit VKR-1R and is sponsored by UGI Gas witness Ms. Vivian K. Ressler as part of her rebuttal testimony (UGI Gas St. No. 3-R). In addition, this adjustment is detailed in UGI Gas Exhibit A (REBUTTAL), which is the Company's final accounting exhibit and is sponsored by UGI Gas witness Ms. Tracy A. Hazenstab as a part of her rebuttal testimony (UGI Gas St. No. 2-R). This correction appears on Schedule C-2.

B. RESPONSE TO I&E WITNESS SAKAYA'S PLANT IN SERVICE ADJUSTMENT

Q. Please summarize how Mr. Sakaya calculated his plant in service adjustments.

A. Mr. Sakaya recommends a total reduction of $137,649,000 to the Company's plant in service claim. I&E St. No. 5 at 5. According to Mr. Sakaya, the Company did not place all of its claimed projected plant in service in its past two rate cases by the end of the FPFTY of those cases. I&E St. No. 5 at 5. Thus, he claims that UGI Gas is receiving a return on plant that was not placed into service. I&E St. No. 5 at 5.

Mr. Sakaya reviewed the plant projected to be placed into service during the FPFTYs for the 2019 Gas Base Rate Case (i.e., FY 2020) and the 2020 Gas Base Rate Case (i.e., FY 2021). He calculated the percent differences between the estimated Gas Plant and estimated Common Plant (as-filed in the Company's 2019 and 2020 Gas Base Rate Cases) against what he claims are the Company's actual plant additions for the FPFTYs in each case. He then applies these percentages to the Company's projected Gas and Common Plant in service during the FTY and FPFTY used in this case (i.e., the years ending September 30, 2022, and September 30, 2023) to arrive at his recommended reductions to the Company's projected total plant in service. I&E St. No. 5 at 10-12.

Q. Does the Company agree with Mr. Sakaya's proposed adjustments to Gas and Common Plant in Service for the FTY and the FPFTY in this case?

A. No. Mr. Sakaya's proposed adjustment should be rejected for three overarching reasons, which I will summarize here and explain in greater detail below.

First, the proper comparison to determine the Company's performance is budgeted plant additions versus actual plant additions, as I described in my direct testimony (UGI Gas St. No. 5). This comparison is commonly used for ratemaking purposes in Pennsylvania, and this comparison generally takes into account data from a 3-year or 5-year period, as discussed below. Mr. Sakaya's analysis does not follow this practice. He instead makes a plant comparison using only 2 years of data, which were impacted by

COVID-19. As a result, he creates an adjustment that is based on an abnormal, non-recurring period of time.

Second, even if it were reasonable to use 2 years of data as Mr. Sakaya has done, there are other problems with the methodology he used to calculate his historical plant comparison. As explained in greater detail below, to calculate his comparison of plant projections to plant actuals, he begins with the projected Gas Plant and Common Plant as-filed in the Company's 2019 and 2020 Gas Base Rate Cases, unadjusted for party adjustments made in those cases or the compromise that was ultimately reflected in the resulting black box settlements. He then fails to use actual plant additions during those years and instead uses a figure that is reduced by the Company's retirements to calculate what he considers to be the Company's plant additions for the FPFTYs in each case.

Third, Mr. Sakaya's criticisms of the Company's budgeting process are without merit, and do not provide a basis for supporting his disallowance.

Fourth, the basic premise for Mr. Sakaya's adjustment, i.e., that, because the Company placed into service less than 100% of the plant it projected to add during the FPFTYs in the 2019 Gas Base Rate Case and 2020 Gas Base Rate Case, the Company was "allowed …to receive a return on plant not placed into service that established rates in those cases" (I&E St. No. 5 at 5), is incorrect.

1. The Use Of A 2-Year Comparison.

Q. What is the basis for using a 3-year to 5-year comparison period, rather than the 2-year comparison advanced by Mr. Sakaya?

A. The comparison of budgeted versus actual plant additions is a common comparison that is regularly used in base rate cases before the Commission. For example, I am advised by counsel that this 3-year to 5-year period was utilized by a utility to justify its projections or by other parties to propose an adjustment to those projections in each of the following recent base rate proceedings:

- *Pa. PUC et al. v. Columbia Gas of Pennsylvania, Inc.*, Docket Nos. R-2020-3018835, et al., at pp. 57-58 (Opinion and Order entered Feb. 19, 2021) (describing the OCA witness's use of 3 years of net plant additions data to propose adjustment to utility's rate base claim);

- *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2019-3015162 – In testimony, OCA proposed to adjust plant additions based on a 4-year average comparison of budgeted capital expenditures to actual plant additions, and the utility justified its plant additions based on a 3-year average comparison of budgeted plant additions to actual plant additions.

- *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2018-3006814 – In testimony, I&E proposed to adjust plant additions based on a 3-year average comparison of budgeted capital spending to actual capital spending, and the utility justified its plant additions based on a 5-year average comparison of budgeted plant additions to actual plant additions.

Importantly, none of these proceedings involve the use of a two-year period to propose an adjustment to, or justify, a utility's claimed plant additions.

Q. Is there further support for the use of a 3-year or 5-year comparison of budgeted versus actual plant additions in the Commission's regulations?

A. Yes. 52 Pa. Code § 53.53, Exhibit A requires a utility to provide data over either a 3-year or 5-year period to assess the reasonableness of its claimed measure of value in rate cases. According to Section 53.53, Exhibit A, the utility is required to do the following with its rate case filings:

> Provide a schedule showing the measures of value and the rates of return at the original cost and trended original cost measures of value at the spot, **three-year and five-year average price levels**. All claims made on this exhibit should be cross-referenced to appropriate exhibits.

This provision of the regulation makes no reference to a 2-year average, such as the one used by Mr. Sakaya.

Q. Do you have additional concerns with Mr. Sakaya's exclusive use of 2-years of data (i.e., initial filing data from the 2019 and 2020 Gas Base Rate Cases)?

A. Yes. Mr. Sakaya's proposal to rely exclusively on FY 2020 and FY 2021 (i.e., the FPFTYs used in the 2019 and 2020 Gas Base Rate Cases, respectively) is unreasonable because of the impacts of the COVID-19 pandemic upon the Company's operations during this time. UGI Gas stopped all non-emergency work that required personnel to be outside their homes for a six-week period beginning in mid-March 2020 and ending on May 4, 2020. As discussed in Timothy J. Angstadt's direct testimony (UGI Gas St. No. 9), the Company then began a ramp-up process as it restarted is construction program, focusing on work that did not involve customer contact. UGI Gas forecasted an increase in its planned capital projects for 2022 due to construction activities that took longer to complete in 2021 because of COVID-19 impacts on the Company's operations. Specifically, UGI Gas had a number of projects that were slightly delayed in the process of completing construction, having a final inspection and then being placed in service for accounting purposes. It is not reasonable to rely exclusively upon the FY 2020 and FY 2021 periods because they are not reflective of the Company's normal operations. Mr. Sakaya's adjustment asks the Commission to set rates in this proceeding based upon abnormal operating conditions, which is contrary to well-recognized ratemaking principles.

Q. Did the Company's initial filing in this case acknowledge the Company's performance in placing capital projects into service during the COVID-19 pandemic?

A. Yes. Both my direct testimony and UGI Gas Exhibit VAS-2 compared the Company's budgeted plant additions to actual plant additions over the last five years, including FY 2020 and FY 2021. UGI Gas Exhibit VAS-2 demonstrated that, accounting for both normal operations during FYs 2017, 2018 and 2019, and abnormal operations during FYs 2020 and 2021, the Company placed 98.0% of budgeted plant additions into service. This close correlation between budgeted and actual plant placed in service over the past five years, including two years impacted by the COVID-19 pandemic, further supports the Company's claimed level of plant in service.

Q. What is the impact of using actual plant placed into service in the last three years of normal operating experience before the COVID-19 pandemic?

A. As shown in UGI Gas Exhibit VAS-2R, the Company placed an average of 102.3% of its budgeted plant additions into service from FY 2017-2019. This demonstrates that during normal historical operating conditions, the Company has a documented history of meeting its budgeted capital project additions.

Q. Does Mr. Sakaya attempt to address the fact that using only FY 2020 and FY 2021 data will result in an understatement of the Company's ability to timely place budgeted FTY and FPFTY plant into service?

A. Yes. He argues that "supply chain difficulties, hiring difficulties, and availability of outside contractors that have been an outcome of the COVID-19 pandemic will persist through the FTY and FPFTY" used in this case. I&E St. No. 5 at 14.

Q. Please respond.

A. Mr. Sakaya provides no basis for these assertions. In fact, these issues have mostly been resolved, as discussed in Mr. Angstadt's direct testimony (UGI Gas St. No. 9). More importantly, however, Mr. Sakaya's claim only takes into account the impacts of "supply chain difficulties, hiring difficulties, and availability of outside contractors" on the Company's completion rate, and does not account for how these issues increase the Company's capital costs.

Q. Please explain how supply chain difficulties, hiring difficulties, and availability of outside contractors have increased and are anticipated to increase the Company's capital costs during the FTY and FPFTY.

A. The inflationary pressure of securing raw materials and the cost of logistics have risen and are now being reflected in the new 2022 contracts that resulted from the 2022 RFP process described in detail in Mr. Angstadt's rebuttal testimony (UGI Gas St. No. 9-R). As described by Mr. Angstadt, while UGI Gas had been successful in holding rates steady for a majority of the pipeline construction contractors from 2018-2021, the new contracts executed as a result of the 2022 RFP reflect current market conditions. The inflationary increases in the contractor prices are not included in the FTY and FPFTY budgeted plant additions because they were not known at the time of preparing the budget. Now the impact of these agreements on the Company's construction costs are reasonably known and measurable.

Q. Please explain how the increased capital costs associated with the new contracts will increase costs for the FTY and FPFTY.

A. The Company summarized the cost increases for the pipeline construction contracts based on the unit cost for capital related to contractor costs for pipeline construction and restoration. The average increase for the capital component of pipeline construction contracts is 17.6% and 27.6% for capital restoration costs. As a result, capital costs are estimated to increase $19.7 million in the FY 2022 and $37.8 million in FY 2023.

Q. Have you prepared a schedule showing the impact on the Company's capital construction program from the increased contractor costs?

A. Yes. Attached to my testimony is UGI Gas Exhibit VAS-3R. The exhibit shows the new business and replacement and betterment costs by charge type in the budget that will be impacted by the new pipeline construction costs. The Company prorated the FY 2022 capital budget since the new contract took effect during the fiscal year. UGI Gas Exhibit VAS-3R multiplies the total contractor costs and restoration costs by the respective percentage increases to calculate the total increase in costs.

Q. Is the Company increasing its projected FTY and FPFTY plant in service additions to reflect the increased capital costs from the new contracts?

A. No. The Company has not increased its claim for plant additions in this case based on the new contracts. We believe, however, that completion of the identified projects for the FTY and FPFTY will result in higher plant costs than those reflected in the Company's direct case. Even if the Commission adopted the 98% completion rate based on the Company's 5-year average and applied it to the Company's plant claim, the FTY and FPFTY cost increases will more than offset any adjustment based on that percentage. Finally, should the Commission accept some portion of Mr. Sakaya's adjustment, the increased costs should be used to offset Mr. Sakaya's proposed reduction in plant additions. *See* UGI Gas Exhibit VAS-4R, line 24 (showing the impact of contractor costs adjustments on Mr. Sakaya's corrected methodology).

Q. Ms. Schappell, did the Company prepare a comparison of budgeted versus actual plant additions, consistent with general ratemaking practice before the Commission, as a part of this proceeding?

A. Yes, as explained in my direct testimony and shown in UGI Gas Exhibit VAS-2, the Company placed 98.0% of budgeted plant additions into service over a 5-year period from FY 2017 through FY 2021. Moreover, as shown in UGI Gas Exhibit VAS-2R, when the Commission considers the Company's historical performance during the 3-year period prior to the COVID-19 pandemic (i.e., FY 2017-2019), the Company placed 102.3% of budgeted plant additions into service. These exhibits and my direct testimony and rebuttal are consistent with generally accepted ratemaking practices and procedures that use 3 to 5 years of data to assess the reasonableness of a utility's projections. These exhibits and my testimony also fully demonstrate that the Company's projected additions for the FTY and FPFTY in this case are reasonable.

On the other hand, Mr. Sakaya's exclusive reliance on 2-years of data, where both years were impacted by abnormal operating conditions due to the COVID-19 pandemic, departs from generally accepted ratemaking practices and procedures, recent cases, and 52 Pa. Code § 53.53. Therefore, it should be rejected by the Commission.

2. Methodology For Calculating Percentage-Based Adjustments.

Q. Please explain the three steps in Mr. Sakaya's calculation of his proposed gas plant installation success rate.

A. I will provide an explanation of Mr. Sakaya's calculation of his asserted gas plant installation success rates. As Mr. Sakaya uses the same method throughout his analysis, I will focus on his analysis for the FPFTY from the 2019 Gas Base Rate Case filing (i.e., FY 2020) as an example. A breakdown of each step of this calculation is as follows:

<u>STEP 1: GAS PLANT 2019 FPFTY</u>

- Mr. Sakaya starts by reciting the Company's estimated Gas Plant as stated in its initial 2019 Gas Base Rate Case filing (filed on January 28, 2019). Mr. Sakaya stated that the Company's initial 2019 Gas Base Rate Case filing projected a total Gas Plant amount of $3,726,871,339 by the end of the FPFTY in that case (i.e., September 30, 2020). He compared this initial estimate against the actual total Gas Plant as of September 30, 2020, which amounted to $3,665,079,106, which he calculated to be a $<u>61,795,233</u> shortfall for Gas Plant.

<u>STEP 2: GAS PLANT ADDITIONS 2019 FPFTY</u>

- Next, Mr. Sakaya recited the Company's Gas Plant Additions as stated in the Company's initial 2019 Gas Base Rate Case filing (filed on January 28, 2019). He states that in its 2019 Gas Rate Case, the Company projected to place in service Gas Plant Additions of $317,833,525 by September 30, 2020. Instead of comparing this against actual plant additions for the FPFTY ending September 30, 2020, Mr. Sakaya created his own calculated Gas Plant Additions. To calculate his plant additions that the Company placed in service for the FPFTY ending September 30, 2020, Mr. Sakaya took the $317,833,525 projection and subtracted the $61,795,233 shortfall (for Gas Plant detailed above) to get his calculated Gas Plant Additions of $256,038,292 for the FPFTY ending September 30, 2020.

STEP 3: GAS PLANT INSTALLATION SUCCESS RATE 2019 FPFTY

- To calculate how successfully the Company performed against its estimates in the 2019 Gas Base Rate Case for Gas Plant placed in service, Mr. Sakaya took his calculated Gas Plant Additions of $256,038,292 for the FPFTY ending September 30, 2020, and divided it by the Company's originally estimated Gas Plant Additions of $317,833,525 (stated in Step 1). This resulted in his 80.56% success rate for Plant Additions for the FPFTY ending September 30, 2020.

UGI Gas Exhibit VAS-4R sets forth the numbers used in each step of Mr. Sakaya's calculations, consistent with the discussion above.

Q. After calculating his proposed Gas and Common Plant installation success rates for FY 2020 and FY 2021, as described above, how did Mr. Sakaya apply these success rates to the Company's case?

A. After calculating his installation success rates, Mr. Sakaya took these percentages, and averaged them, producing an average installation success rate of 83.69% for Gas Plant and an average installation success rate of 67.67% for Common Plant. Mr. Sakaya then applied the average to the Company's projected Gas and Common Plant in service amount for the FPFTY in this case to arrive at his total proposed $137,649,000 plant in service disallowance.

Q. Do Mr. Sakaya's calculations of proposed Gas and Common Plant installation success rates for FY 2020 and FY 2021 lack merit?

A. Yes. As an initial matter, Mr. Sakaya offers no proof to demonstrate that the Company's comparison of actual capital additions to budgeted capital additions was incorrect. Moreover, his alternative calculation is not supported by sound accounting principles.

Q. What do you believe are the specific problems associated with Mr. Sakaya's calculations?

A. As explained below: (1) Mr. Sakaya's method uses an improper starting point for measuring the Company's proposed plant additions in the 2019 and 2020 Gas Base Rate Cases; (2) Mr. Sakaya's proposed calculation of plant additions are not based on actual plant additions (contained in the Company's accounting records) but rather a figure that is derived from subtracting retirements from the Company's actual plant additions; and (3) Mr. Sakaya's breakout of Gas Plant and Common Plant is inconsistent with the Company's budgeting process and work streams.

Q. Please explain your assertion that Mr. Sakaya's proposed calculation of plant additions are not based on the actual plant in service figures ultimately proposed by the Company in the 2019 and 2020 Gas Base Rate Cases.

A. Instead of comparing the most relevant figures, i.e., Actual and Budgeted Plant Additions as provided in the Company's initial filing in this case, Mr. Sakaya begins his analysis with the projected plant in service figures as stated in the initial 2019 and 2020 Gas Base Rate Case filings. Importantly, those initial estimates were revised during the course of both cases as a part of the Company's rebuttal presentation, a fact that Mr. Sakaya does not acknowledge.

- In the 2019 Gas Base Rate Case, the Company reduced its initially filed total plant in service for the FPFTY used in that case from $3,950,991,000 (*see* Docket No. R-2018-3006814, Book V, UGI Gas Exhibit A (Fully Projected), Schedule C-2, page 5) to $3,946,337,000 (*see* Docket No. R-2018-3006814, UGI Gas Exhibit A - FPFTY (Rebuttal), Schedule C-2, page 5). This amounts to a 0.1% reduction to total projected plant in service.

- In the 2020 Gas Base Rate Case, the Company reduced its initially filed total plant in service for the FPFTY used in that case from $4,324,364,000 (*see* Docket No. R-2019-3015162, Book V, UGI Gas Exhibit A (Fully Projected), Schedule C-2, page 5) to $4,286,292,000 (*see* Docket No. R-2019-3015162, UGI Gas Exhibit A - FPFTY (Rebuttal), Schedule C-2, page 5), as explained in the rebuttal testimony submitted by Vivian Ressler (i.e., UGI Gas Statement 3-R in that case). This amounts to a 0.9% reduction to total projected plant in service.

Moreover, Mr. Sakaya's reliance on the original projections presented in the initial 2020 Gas Base Rate Case filing disregard the fact that those amounts were calculated before the COVID-19 pandemic took hold. The Company lowered its original projections during that case as a result of the COVID-19 pandemic, as set forth above and as explained in the rebuttal testimonies of UGI Gas witnesses Mr. Brown and Ms. Ressler (UGI Gas Statements 1-R and 3-R in that case). In this regard, his comparison starts from the wrong place.

Q. Please explain why Mr. Sakaya's claimed plant in service figures are not actual plant in service figures.

A. As stated previously, Mr. Sakaya did not use actual Plant Addition figures as documented by the Company pursuant to acceptable accounting standards. As described in Step 2 of each of the calculations summarized above, Mr. Sakaya took the Company's initial projection for Gas/Common **Plant In Service** for the FPFTY in each of the prior base rate cases, and subtracted the shortfall he calculated using the difference between Company's initial projection for total Gas/Common **Plant Additions** for the FPFTY in each of the prior base rate cases and actual Gas/Common **Plant Additions** for the same period. This calculation combines two comparisons (i.e., his calculated shortfall based on Gas/Common **Plant Additions**, is subtracted from initially projected total Gas/Common **Plant In Service**), instead of consistently comparing the Company's projected Gas/Common **Additions** to its actual Gas/Common **Additions**. Where the initially projected total Gas/Common **Plant In Service** includes the effect of retirements, the calculated shortfall based on Gas/Common **Plant Additions** does not.[1] In this regard, Mr. Sakaya's calculations are an inconsistent combination of apples and oranges, instead of only apples.

Accordingly, Mr. Sakaya's methodology misleadingly makes it look like the Company has been less successful at installing Plant in Service than it truly was. His calculations and conclusions regarding the Company's Plant in Service success rates over FY 2020 and FY 2021 are flawed.

Q. Please explain how Mr. Sakaya's calculation does not properly consider the impact of projected and actual retirements during FY 2020 and FY 2021.

A. Mr. Sakaya's method improperly includes retirements in his proposed average percentage to be applied to Gas and Common Plant placed in service. However, factoring in retirements to the basis for his adjustment disregards the fact that retirements have a zero-net change to net plant in service or rate base. The impact of retirements must be included

[1] UGI Gas Exhibit A (Fully Projected), Schedule C-2 of the Company's initial filing in this case, and in the 2019 and 2020 Gas Base Rate Cases, shows the impact of retirements on projected total plant in service. The Company's total plant in service for the FPFTY starts with the FTY-ending balance of plant in service, adds to this amount projected FPFTY additions, and then subtracts projected FPFTY retirements.

in both the projected and actual plant additions, as well as projected and actual accumulated depreciation.

Q. What impact does Mr. Sakaya's failure to properly account for retirements have on his proposed adjustment?

A. The failure to properly account for retirements understates the Company's plant additions by $131.1 million dollars. *See* UGI Gas Exhibit VAS-4R, line 20. Mr. Sakaya's use of retirements to reduce plant additions further undermines the already improper calculations.

Q. You also testified that Mr. Sakaya's breakout of Gas Plant and Common Plant additions is improper. Please explain.

A. The Company does not budget this way and does not have work streams divided in this manner. The Company's claim is based on total additions, and it is reasonable to review the Company's Plant in Service success in that manner. Mr. Sakaya's breakout of Gas Plant and Common Plant additions is not consistent with the Company's operations or accounting, and in concert with his misuse of retirements in his methodology, results in an overstatement of his proposed adjustment by $51.1 million. *See* UGI Gas Exhibit VAS-4R, line 22.

Q. Have you quantified the impact of the incorrect factors incorporated in Mr. Sakaya's methodology?

A. Yes, I have. While I believe the Commission should reject Mr. Sakaya's methodology for the reasons stated above, if the Commission were to use the methodology recommended by Mr. Sakaya, it must correct the flaws in his methodology. I have done so in UGI Gas Exhibit VAS-4R.

Walking through these corrections, I first compared the initial projection for Gas/Common Plant additions for the FPFTY in each of the prior base rate cases to the actual plant additions for the same period. I then divided the actual plant additions ($687,447,330) (*see* UGI Gas Exhibit VAS-4R, line 14) by the initial projections in the FPFTY ($762,892,037) (*see* UGI Gas Exhibit VAS-4R, line 13), to calculate the installation success rate for total Gas/Common plant additions of 85.6% and 94.1% for the 2019 and 2020 Gas Base Rate case, respectively. *See* UGI Gas Exhibit VAS-4R, line 15. Mr. Sakaya calculated installation success rates of 79.4% and 82.0% in I&E Exhibit No. 5, Schedule 4, at 1 and 2. *See* UGI Gas Exhibit VAS-4R, line 6. Mr. Sakaya applied his installation success rate percentages separately, when they should be applied collectively to calculate the installation success rate percentages in total. *See* UGI Gas Exhibit VAS-4R, line 15 (2 Year Total Plant).

Correcting his methodology reduces Mr. Sakaya's proposed disallowance by $51,114,231 (*see* UGI Gas Exhibit VAS-4R, line 22), from a disallowance of $137,649,000 (*see* UGI Gas Exhibit VAS-4R, line 12) for plant in service to a disallowance of $86,535,029 (*see* UGI Gas Exhibit VAS-4R, line 21).

Q. Do you have any further comments on Mr. Sakaya's methodology?

A. Yes. The data I have presented indicates that the Commission must conclude that not only is Mr. Sakaya's outcome incorrectly calculated, but it is not logical or appropriate. Even using the corrected version of Mr. Sakaya's methodology provided in UGI Gas Exhibit

VAS-4R, the methodology takes an average over a two-year period where there were significant and anomalous operational impacts. The outcome of this methodology would produce a result that is significantly lower than the experienced HTY in this case. The outcome of this methodology also provides no acknowledgement or adjustment for either the further recovery experienced by the Company in its post-COVID operations moving back to normal performance or the significant impacts of inflation on the Company's anticipated future costs. There is no logical basis for the Commission to adopt a success rate for plant in service that is lower than the 94.1% shown in UGI Gas Exhibit VAS-4R. And, in fact, I have shown numerous reasons that the Commission should conclude that no adjustment is needed to the Company's plant in service claim in this proceeding.

3. Budgeting Criticism.

Q. Mr. Sakaya argues that the Company's percent of budgeted plant completed is not a valid comparison on page 13 of his direct testimony. Do you agree?

A. No. UGI Gas undertakes an annual process to review its budgets and to adjust them as needed to reflect operating conditions and changed circumstances. Over the 5-year period of FY 2017 through 2021, the Company on average placed 98.0% of its budgeted plant additions into service. This percentage takes into account the movement of projects from one year to the next and the impact of bringing future year projects into an earlier year. For example, the Company budgeted an increase of approximately $56 million over its planned capital spending for FY 2021. A significant portion of this increase was due to the 2020 construction activities that were delayed and or/rescheduled when the Company temporarily halted non-essential emergency work from mid-March to early May due to the COVID-19 pandemic. This is an example of the need to reflect current operating conditions and changed circumstances during the annual budget process. Mr. Sakaya's criticism of the Company's budgeting process does not provide a basis for his disallowance.

4. Return On Plant Placed Into Service.

Q. Does Mr. Sakaya make any further arguments regarding the the Company's claimed gas and common plant in service during the FTY and FPFTY based on his calculations detailed above?

A. Yes, Mr. Sakaya asserts that the Company did not place into service all the plant it projected to place into service during the FPFTYs of the 2019 Base Rate Case and the 2020 Base Rate Case. I&E St. No. 5 at 5. He further argues that "[s]ince rates in those cases were based upon the plant at the end of the FPFTY, this allowed the Company to receive a return on plant not placed into service that established rates in those cases." I&E St. No. 5 at 5.

Q. Do you agree with Mr. Sakaya's claim?

A. No. Mr. Sakaya is incorrect in his assertion that the Company has received a return on plant that was not placed into service but was included in base rates. As previously stated, Mr. Sakaya's analysis focuses on the Company's projections included in the initial filings of both cases. As explained in detail above, both the 2019 and 2020 Gas Base Rate Cases included updates during the course of the proceeding that impacted plant in service. However, the most critical flaw in Mr. Sakaya's claim is that the rates produced in both of those prior proceedings were the subject of black box settlements. Therefore, the Company earned a return based upon the rates approved as a part of each settlement, ***not*** upon the proposed rates initially filed in each case. It is simply incorrect for Mr. Sakaya to assert that the Company earned a return in each of those cases based upon the projected additions included in each initial filing.

III. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit VAS-1R

(No Public Version Available)

UGI Gas Exhibit VAS-2R

UGI UTILITIES, INC. - GAS DIVISION
Plant Placed in Service compared to Budget
$ amounts in '000s

	2017		2018		2019		3 Year Average		
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Actual vs. Budget
Growth	$ 44,776	$ 39,788	$ 58,645	$ 77,356	$ 69,288	$ 61,681	$ 172,709	$ 178,825	$ 6,116
IT	$ 63,661	$ 76,619	$ 22,338	$ 14,345	$ 67,809	$ 63,652	$ 153,808	$ 154,616	$ 808
Other	$ 17,342	$ 14,073	$ 17,806	$ 12,756	$ 63,907	$ 58,437	$ 99,056	$ 85,266	$ (13,789)
Replacement and Betterment	$ 149,591	$ 166,349	$ 185,392	$ 204,472	$ 196,274	$ 189,279	$ 531,257	$ 560,100	$ 28,843
Total Additions	$ 275,370	$ 296,829	$ 284,181	$ 308,929	$ 397,278	$ 373,049	$ 956,829	$ 978,807	$ 21,978
					$ -		**(1)**	**(2)**	
							(2) / (1)	**102.3%**	

UGI Gas Exhibit VAS-3R

UGI Utilities, Inc. - Gas Division
Pipeline and Restoration Contract Increase
For the Years Ending September 30, 2022 through 2023

Fiscal Year Ending September 30, 2022

Budget Group	Pillar	Contractor	Equipment	Service Costs (Pipeline)	Total Contractor Costs	Restoration	Total Costs
40G	Growth	104,499	-		104,499	2,195	106,694
40G1	Growth	655,000	-		655,000	-	655,000
50G	Growth	-	-		-	-	-
51G	Growth		3,207,536		3,207,536		3,207,536
57G	Growth	-	-		-	-	-
01O	Replacement and Betterment		150,000		150,000		150,000
09O	Replacement and Betterment	25,452,531			25,452,531	15,000	25,467,531
12O	Replacement and Betterment	14,713,780			14,713,780	907,830	15,621,610
41M	Replacement and Betterment	1,304,954	-		1,304,954	584,610	1,889,564
43M	Replacement and Betterment	9,155,287	-		9,155,287	1,866,070	11,021,357
44M	Replacement and Betterment	27,990,603	33,215	2,103,148	30,126,966	7,724,734	37,851,700
45M	Replacement and Betterment	50,463,483	2,568	335,600	50,801,651	13,761,884	64,563,535
51M	Replacement and Betterment		4,748,577		4,748,577		4,748,577
52M	Replacement and Betterment	1,034,127	-		1,034,127	-	1,034,127
54M	Replacement and Betterment	207,855			207,855		207,855
58M	Replacement and Betterment	27,188,415	-	240,000	27,428,415	1,270,388	28,698,802
Grand Total		$ 158,270,534	$ 8,141,896	$ 2,678,748	$ 169,091,178	$ 26,132,710	$ 195,223,888
Proration of Budget (May - September)					53.3%	53.3%	
FY 2022 Prorated Budget					$ 90,048,150	$ 13,916,765	$ 103,964,915
Pipeline Contract Increase					17.6%	27.6%	
FY 2022 Increase					$ 15,843,338	$ 3,839,974	$ 19,683,312

Fiscal Year Ending September 30, 2023

Budget Group	Pillar	Contractor	Equipment	Service Costs (Pipeline)	Total Contractor Costs	Restoration	Total Costs
40G	Growth	$ 99,888	$ -		$ 99,888	$ -	$ 99,888
40G1	Growth	-	-		-	-	-
50G	Growth	-	-		-	-	-
51G	Growth		3,078,485		3,078,485		3,078,485
57G	Growth	-	-		-	-	-
09O	Replacement and Betterment	26,754,725	73,080		26,827,805	-	26,827,805
12O	Replacement and Betterment	9,112,475			9,112,475	676,025	9,788,500
41M	Replacement and Betterment	1,298,577			1,298,577	-	1,298,577
43M	Replacement and Betterment	7,617,494	-	95,000	7,712,494	826,700	8,539,194
44M	Replacement and Betterment	35,664,647	-	1,593,202	37,257,849	5,376,337	42,634,186
45M	Replacement and Betterment	61,894,235		573,800	62,468,035	13,388,756	75,856,791
51M	Replacement and Betterment		4,303,578		4,303,578		4,303,578
52M	Replacement and Betterment	782,450			782,450	-	782,450
54M	Replacement and Betterment	207,855			207,855		207,855
58M	Replacement and Betterment	27,489,519	-	240,000	27,729,519	1,328,907	29,058,426
Grand Total		$ 170,921,865	$ 7,455,143	$ 2,502,002	$ 180,879,010	$ 21,596,724	$ 202,475,734
Pipeline Contract Increase					17.6%	27.6%	
FY 2023 Increase					$ 31,824,388	$ 5,959,062	$ 37,783,450
Total FY 2022 and 2023 Increase					**$ 47,667,726**	**$ 9,799,036**	**$ 57,466,761**

UGI Gas Exhibit VAS-4R

UGI UTILITIES, INC. - GAS DIVISION
Walk-Through of Mr. Sakaya's Calculation

Line No.	Description	2019 Gas Base Rate Case FPFTY September 30, 2020 Gas Plant	Common Plant	Total Plant	2020 Gas Base Rate Case FPFTY September 30, 2021 Gas Plant	Common Plant	Total Plant	
	Step 1							
1	Projected Plant Amount in Rate Case	3,726,871,339	224,119,817	3,950,991,156	4,051,158,640	273,205,211	4,324,363,851	
2	Actual Plant Balance	3,665,076,106	226,134,102	3,891,210,208	4,007,295,267	239,732,387	4,247,027,654	
3	Shortfall / Overage	(61,795,233)	2,014,285	(59,780,948)	(43,863,373)	(33,472,824)	(77,336,197)	(1) - (2)
	Step 2							
4	Projected Plant Additions Incorrectly Including Retirement Offset	317,833,525	15,075,391	332,908,916	333,095,498	42,900,534	375,996,032	
5	Calculated Plant Additions Incorrectly Including Retirement Offset	256,038,292	17,089,676	273,127,968	289,232,125	9,427,710	298,659,835	(3) + (5)
	Step 3							
6	Installation Success Rate	80.56%	113.36%	82.04%	86.83%	21.98%	79.43%	(5) / (6)
7	Two Year Average Installation Success Rate				83.69%	67.67%		Average (6)
8	FTY 2022 Projected Plant Additions Incorrectly Including Retirement Offset				355,331,865	(4,939,530)	350,392,335	
9	FPFTY 2023 Projected Plant Additions Incorrectly Including Retirement Offset				389,254,772	55,160,566	444,415,338	
10	Total Projected Plant Additions Incorrectly Including Retirement Offset				744,586,637	50,221,036	794,807,673	(8) + (9)
11	Proposed Projected Plant Additions Incorrectly Including Retirement Offset				623,174,340	33,984,073	657,158,413	(7) * (10)
12	Proposed Adjustment to Capital Additions				(121,412,297)	(16,236,963)	(137,649,260)	(11) - (10)

Corrected Walk-Through of Mr. Sakaya's Calculation

Line No.	Description	2019 Gas Base Rate Case FPFTY September 30, 2020 Gas Plant	Common Plant	Total Plant	2020 Gas Base Rate Case FPFTY September 30, 2021 Gas Plant	Common Plant	Total Plant	2 Year Total Total Plant	
	Step 1								
13	FPFTY Projected Additions in Rate Case Per Depreciation Study Table 3	340,145,728	17,316,736	357,462,464	358,602,036	46,827,537	405,429,573	762,892,037	
14	FPFTY Actual Additions Per Schedule C-2	292,069,059	13,909,723	305,978,782	360,533,199	20,935,349	381,468,548	687,447,330	
15	Installation Success Rate			85.6%			94.1%	90.1%	(14) / (13)
16	FTY 2022 Projected Plant Additions Per Depreciation Study Table 3							398,403,797	
17	FPFTY 2023 Projected Plant Additions Per Depreciation Study Table 3							476,632,869	
18	Total Projected Plant Additions							875,036,666	(16) + (17)
19	Mr. Sakaya's Methodology Corrected (Removing Impact of Retirements)							788,501,637	(15) * (18)
20	Mr. Sakaya's Understatement in Plant Additions Due to Methodological Errors							(131,343,224)	(11) - (19)
21	Corrected Adjustment to Capital							(86,535,029)	(19) - (18)
22	Mr. Sakaya's Overstatement of Plant Adjustment							51,114,231	(21) - (12)
23	Total Contractor Cost Increases in VAS-3R							57,466,761	
24	Mr. Sakaya's Adjustment Net of Contractor Cost Adjustments from VAS-3R							(29,068,268)	(21) + (23)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218,et al.

UGI Utilities, Inc. – Gas Division

Statement No. 6-R

Rebuttal Testimony of
Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Topics Addressed: **Cost of Capital**
Capital Structure
Rate of Return

Dated: May 17, 2022

23912443v1

UGI Utilities, Inc. - Gas Division
Rebuttal Testimony of Paul R. Moul
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REBUTTAL TESTIMONY OF PAUL R. MOUL

INTRODUCTION

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division. ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 6, on January 28, 2022.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony submitted by David J. Garrett, a witness appearing on behalf of the Office of Consumer Advocate ("OCA"), and Anthony Spadaccio, a witness appearing on behalf of the Bureau of Investigation and Enforcement ("I&E").

Q. What are the key aspects of the rate of return issue that the Pennsylvania Public Utility Commission ("Commission") should consider when deciding this issue in this case?

A. The issues involve the Company's cost of equity, the capital structure and the cost of debt. Mr. Spadaccio has accepted the Company's proposed capital structure ratios. Mr. Garrett has opposed the actual capital structure, and instead proposed a hypothetical capital structure. All the witnesses have accepted the embedded cost of debt for UGI Gas. As I will detail below, the increase in interest rates that occurred after the Company's original filing requires an update of the cost of debt for UGI Gas.

In each instance, the equity returns proposed by the opposing witnesses are entirely too low to reflect the risks of UGI Gas and the prospective cost of equity. Aside from technical issues that I will discuss later in my rebuttal testimony, the Commission should take into consideration a rate of return that will reflect and be supportive of the Company's financial and risk profile. As I explain below, the opposing parties' recommendations fail to adequately consider this point and thereby understate the required cost of common equity in this proceeding.

Q. Please summarize the key points of your rebuttal testimony.

A. My key points are:

- o Capital Structure Ratios – Mr. Garrett's use of a hypothetical capital structure, rather than the Company's projected actual capital structure for the FPFTY, is improper and contrary to standard practice in Pennsylvania.
- o Cost of Debt – The embedded cost of debt for the FPFTY has been adjusted to reflect higher interest rates.
- o Comparable Companies – Mr. Spadaccio has made erroneous deletions from my gas company barometer group by eliminating New Jersey Resources and Southwest Gas. Mr. Garrett accepts my group.
- o Discounted Cash Flow ("DCF") – A variety of DCF results are clearly too low to provide a reliable measure of the cost of equity. This can be traced to the formulaic approach taken by Mr. Spadaccio in applying this model (see page 21 of I&E Statement No. 2). In addition, Mr. Garrett fails to adequately reflect investor expectations of growth that are specific to the natural gas companies included in his proxy group.
- o DCF Leverage Adjustment – Mr. Spadaccio has not refuted the accuracy of the Company's leverage adjustments to the DCF and beta component of the Capital Asset Pricing Model ("CAPM"). Mr. Garrett claims that my leverage adjustment is "incorrect" (see page 47 of OCA Statement No. 3). But he has not shown that the capital structure ratios and calculations of the leverage adjustment are in any way incorrect.
- o CAPM – A reasonable application of the CAPM mandates using 30-year

Treasury bond yields, leverage adjusted betas, and size adjustment and indicates an equity cost rate that is well above 11% in this case. Indeed, Mr. Spadaccio has proposed a 12.13% CAPM result in this case.

- Additional methods should also be considered when establishing the cost of equity for UGI Gas. This is especially important because FOMC policy and inflation in the last few months indicates a higher cost of equity and that both witnesses have chosen not to even mention this in their testimony.

Q. How should the rate of return set by the Commission support the Company's financial profile?

A. The Commission should set the Company's return on equity at a level that will attract investment in the Company to ensure the Company's financial ability to render safe and reliable service. Applying this principle, the Commission should reject the proposals by Messrs. Spadaccio and Garrett to cut the Company's return on common equity to 9.92% and 8.50%, respectively. Equity returns of this magnitude would be viewed by investors as unsupportive of the Company's financial condition. While Mr. Spadaccio's proposed return on equity borders on a reasonable one, Mr. Garrett's proposed return is completely unreasonable because it is much too low to allow UGI Gas to achieve the level of returns that meet investors' expectations. Indeed, Mr. Garrett actually claims that the UGI Gas cost of equity is just 7.0%, but he increases it to 8.5%. Even Mr. Garrett recognizes that setting the ROE at his calculated 7.0% "could have the undesirable effect of notably increasing the Company's risk profile," so he arbitrarily increases his recommendation to 8.5% (see OCA Statement No. 2, page 7). However, he provides no explanation why 8.5% would be reasonable now when the Commission approved 9.86% in the Columbia rate case in early 2021 and 10.24% in the PECO gas rate case also in 2021, in the midst of the COVID-19 Pandemic ("Pandemic"). Afterward, there has been dramatic increases in inflation and interest rates, prompting the Federal Open Market Committee ("FOMC") to increase the federal funds rate to combat inflation. This fact has not even been mentioned in either of their testimony. Further, acceptance of Mr. Garrett's approach would ultimately lead to even lower ROEs in the future since the 8.5% is simply a process to reduce ROEs based on his gradualism approach to ratchet downward the ROE. Rather, based on the factors listed below, and for technical reasons set forth later in my rebuttal testimony, the Commission should adopt a substantially higher ROE.

Q. How does Mr. Garrett's 7.0% cost of equity proposal compare to other recognized returns?

A. Mr. Garrett determined that the DCF cost of equity is 6.7% and the CAPM cost of equity is 7.2%. These returns compare to the 10.00% DCF return and 10.88% CAPM return established in the Commission's Quarterly Earnings report for the same group of companies considered by Mr. Garrett. And as mentioned, the Commission awarded 10.24% in the PECO case last Fall. This comparison establishes that Mr. Garrett's position is unreasonable.

Q. Are there additional issues that the Commission should consider when setting the Company's return?

A. Yes. The investment community would be very concerned if the Commission were to adopt the position of the OCA in this case. If it were to do so, investors would see Pennsylvania regulation as less supportive of the Company at a time of high levels of capital investment and increasing capital cost rates. Over the next five years, UGI Utilities, Inc. expects capital expenditures to be $1.960 billion. If the Commission were to follow the proposal of reducing ROEs as proposed by the OCA, Pennsylvania's regulatory support would certainly be viewed by investors as being reduced, particularly in the context of rising capital costs due to inflation. The return on equity used by the Commission to set rates embodies in a single numerical value a clear signal of regulatory support for the financial strength of the utilities that it regulates. Although cost allocations, rate design issues, and regulatory policies relative to the cost of service are important considerations, the opportunity to achieve a reasonable return on equity represents a direct signal to the investment community of regulatory support (or lack thereof) for the utility's financial strength. In a single figure, the return on equity utilized to set rates provides a common and widely understood benchmark that can be compared from one company to another and is the basis by which returns on all financial assets (stocks – both utility and non-regulated, bonds, money market instruments, and so forth) can be measured. So, while varying degrees of sophistication are required to interpret the meaning of specific Commission policies on technical matters, the return on equity figure is universally understood and communicates to investors the types of returns that they can reasonably expect from an investment in utilities operating in Pennsylvania.

Q. How does the cost of equity proposal by Mr. Garrett compare to the utility returns recently authorized by the Commission?

A. Technical disputes about methodology and data aside, the cost of equity proposed by Mr. Garrett is simply not representative of the returns that the Commission has been awarding. Indeed, the Commission established a 9.85% equity return for the Electric Division rate case for UGI Utilities, Inc. at Docket No. R-2017-2640058. Since that time, the Commission granted equity returns of 9.54% for Citizens' Electric Company at Docket No. R-2019-3008212, 9.31% for Wellsboro Electric Company at Docket No. R-2019-3008208, 9.73% for Valley Energy at Docket No. R-2019-3008209, 9.86% for Columbia Gas of Pennsylvania at Docket No. R-2020-3018835, and 10.24% for the Gas Division of PECO Energy at Docket No. R-2020-3018929. Moreover, for purposes of setting the Distribution System Improvement Charge ("DSIC"), the Commission has set a 10.20% equity return for gas utilities at Docket No. M-2021-3030045 (adopted at the Public Meeting held January 13, 2022). In the DSIC proceedings, DSIC recoveries are reconciled and therefore the 10.20%

is guaranteed. In a base rate case such as this, a higher equity return is required because that return provides only an opportunity and not a guarantee for the natural gas utilities.

The rate of return on common equity of 8.50% proposed by Mr. Garrett is seriously deficient and will not provide UGI Gas with the opportunity to earn its investor required cost of capital for the fully projected future test year ending September 30, 2023 ("FPFTY"). As explained below, this is not the time for the Commission to be reducing the Company's authorized return when there is a compelling need for capital investment to rehabilitate aging infrastructure.

Q. Should the Commission consider the future trend in capital costs when deciding the return on equity in this case?

A. Yes. Unlike Mr. Garrett, who takes a backward view of interest rates, accommodative policy by the FOMC has ended and higher interest rates have occurred and will continue in the future. Current FOMC policy will produce even higher interest rates prospectively that should be incorporated into the cost of equity now. Indeed, higher inflation expectations are a contributing factor that points to higher interest rates. Higher inflation today is revealed by a 5.9% increase in social security payments announced on October 13, 2021, the largest one-year increase in nearly four decades. The annual inflation rate in March 2022 was 8.5%, the highest rate since December 1981. After the FOMC ended its bond buying program (i.e., quantitative easing) in March 2022, it now plans to run off its $9 trillion asset portfolio, which will further boost interest rates. Moreover, the first of several Fed Funds increases occurred on March 16, 2022 with an increase of 0.25% and an additional 0.50% increase occurred on May 4, 2022. A 50 basis point increase in the Fed Funds rate has not occurred since 2000. Additional increases are expected in 2022 and 2023. Higher interest rates clearly point to higher capital costs prospectively. A forward-looking assessment of the capital markets is especially relevant here because the Company's rates will be based on a FPFTY. The yield on 10-year Treasury bonds moved above the 3% level on May 2, 2022, the first time since late 2018. By April 2022, the yield on 30-year Treasury bonds moved to 2.81%, or an increase of 1.14% (or 68%) since December 2020. Likewise, the yield on A-rated public utility bonds has increased to 4.32% in April 2022 from 2.77% in December 2020 – a 1.55 basis point (or 56%) increase. Higher interest rates clearly point to higher capital costs prospectively. I will describe the forecasts of interest rates and the trend below.

Q. Is there additional evidence that suggests that the cost of capital has been increasing?

A. Yes. To gain a consensus view of future interest rates, I tabulated the forecasts of yields on 10-year Treasury notes published by a variety of well recognized and investor-influencing sources. I chose the 10-year Treasury note because it is available on a consistent basis across all sources. The comparisons are:

	2023	2024	2025	2026	2027	Change in Basis Points
Blue Chip	2.40%	2.80%	3.10%	3.20%	3.20%	80
EIA	1.36%	1.57%	1.80%	2.03%	2.25%	89
CBO	2.03%	2.29%	2.57%	2.79%	2.98%	95

The universal consensus is that interest rates will increase in the future. The rising level of interest rates represents one key factor that adds to the risk of common equity. It is apparent that the trough in interest rates has passed and the forecasts show interest rates will continue to rise in the future. The Commission should take the forecast trend toward higher interest rates into account when it sets the cost of equity for UGI Gas. Mr. Garrett's testimony considers only a 30-day historical average of 30-year Treasury bond yields ended April 5, 2022. There, he concludes the historical average of 2.40% is appropriate in his view. We know that the yield today is above 2.40% and forecast to go higher with high inflation and forecasted fed funds increases. As such, his cost of equity analysis is defective because he has not taken into account the general consensus that interest rates will increase in the future from current levels. It is therefore indicated that a higher authorized return is warranted in the face of higher expected interest rates.

Q. Has the stock market reacted to the changes in interest rates?

A. Yes. The stock market entered "correction" territory in 2022. Overall market sentiment is revealed by investor expected volatility, which provides an overall assessment of the risk that prevails in the equity market. The risk associated with common stock investments is revealed by the volatility of the stock market measured by the Chicago Board Options Exchange ("CBOE") VIX. The CBOE VIX is based on real-time prices of options on the S&P 500 Index and is designed to reflect investors' consensus view of future (30-day) expected stock market volatility. It is well-established that greater volatility indicates higher risk, which, all else equal, translates into a higher cost of equity. It is widely accepted that high readings for the CBOE VIX are often accompanied by bearish sentiment and a low CBOE VIX is associated with bullish sentiment. The trading pattern of the CBOE VIX is typically inverse to the level of stock prices. That is to say, the CBOE VIX increases when stock prices are falling, and the CBOE VIX declines when stock prices rise. This situation is sometimes associated with increases in the cost of equity when the CBOE VIX increases and vis-a-versa. For 2022 to date, the CBOE VIX was 27.64. This compares with the CBOE VIX of 19.78 in 2019 prior to the beginning of the financial consequences of the Pandemic. We can see that the CBOE VIX spiked upward with the beginning of the Pandemic. Since the Company's last rate case, the CBOE VIX has been:

Year	Average VIX
2019	19.78
2020	48.61
2021	25.41
2022 YTD	27.64

While volatility in the stock market has subsided since the beginning of the Pandemic in 2020, it continues to significantly exceed pre-Pandemic levels. The current level of risk associated with common stocks, as revealed by the higher CBOE VIX in 2022, warrants a higher equity return at this time because the higher stock market volatility signifies higher risk that requires higher returns in compensation for the higher risk. Hence, the risk for common equity, which translates into the cost of equity, does not support a low equity return as suggested by Mr. Garrett.

Q. How is the remainder of your testimony organized?

A. I will cover the issues of (i) capital structure, (ii) cost of debt, (iii) the composition of the proxy (i.e., barometer) group, (iv) the weight to be given to the DCF method, (v) the DCF growth rate, (vi) the leverage adjustment to the DCF and CAPM methods, (vii) the CAPM method, (viii) the Risk Premium analysis, (ix) Comparable Earnings, and (x) management performance as part of the return on equity consideration.

CAPITAL STRUCTURE RATIOS

Q. Is there a difference in the proposed capital structure ratios utilized by the rate of return witnesses in this case?

A. Yes. Mr. Garrett is alone in advocating a hypothetical capital structure for UGI Gas. Mr. Spadaccio has accepted the Company's proposed capital structure, as it falls within the range of capital structures of the proxy group. Mr. Garrett's position is clearly contrary to long-standing Commission policy concerning capital structure ratios, most recently articulated in the Gas Division rate case of PECO Energy at Docket No. R-2020-3018929 (Order entered June 22, 2021). In the Commission’s Columbia decision at Docket No. R-2020-3018835 (Order entered February 19, 2021), the Commission accepted Columbia’s equity ratio of 54.19% (Columbia Order, p. 118). In the Commission’s PECO decision, Docket No. R-2020-3018929, (Order entered June 22, 2021), the Commission accepted PECO’s equity ratio of 53.38% common equity. The Commission’s long-standing policy is to accept the Company's actual capital structure for the FPFTY as long as it is within the range of the capital structures employed by the barometer group companies. In a UGI case, the Commission observed that generally hypothetical capital structure ratios usurp the prerogative of management unless it can be demonstrated that management has acted imprudently and the resulting actual capital structure ratios are atypical (1984 Pa. PUC LEXIS 61, *85, 58 Pa. PUC 155, 187 (Pa. P.U.C. January 26, 1984)). Essentially, the Commission will accept a utility's actual capital structure ratios as long as they are reasonable. This is the case for UGI Gas.

Q. What capital structure ratios do Mr. Garrett propose?

A. Mr. Garrett proposes a hypothetical capital structure for UGI Gas without ever demonstrating that the Company's proposed capital structure is unreasonable. Rather, his proposed capital structure merely lowers the Company's revenue requirements.

In reaching his conclusion on capital structure ratios, Mr. Garrett examined (i) the debt ratios of the companies in his proxy group, as well as the Parent Company of UGI Gas, and (ii) the debt ratios of thousands of other companies, which this position is inconsistent with his rejection of the Comparable Earnings approach to measuring the cost of equity.

His approach essentially involves the use of a hypothetical capital structure that violates Commission precedent on the use of the actual capital structure. Under the facts of this case, the use of the UGI Gas actual capital structure ratios comports with Commission precedent.

Q. Is there any basis to deviate from the Company's actual capital structure to set the rate of return in this case?

A. No. As Mr. Spadaccio explained (see page 11 of I&E Statement No. 2), the Company's actual capital structure ratios (including the 55.12% common equity ratio) falls within the range of the proxy group. This is sufficient to meet the Commission's standard that makes the actual UGI Gas capital structure appropriate in this case.

Rather than altering the Company's actual capital structure, Mr. Garrett might have been led to a different conclusion if he had considered the common equity ratios utilized by the Commission in recent rate case decisions. Indeed, in its Order Entered on October 25, 2018 in Docket No. R-2017-2640058, the Commission adopted a 54.02% common equity ratio for the Electric Division of UGI Utilities. Furthermore, the Commission accepted a 54.19% common equity ratio in the Columbia Gas of Pennsylvania rate case at Docket No. R-2020-3018835 (Order entered February 19, 2021) and 53.38% common equity ratio for the Gas Division of PECO Energy at Docket No. R-2020-3018929 (Order entered June 22, 2021). Each of these common equity ratios are well above the 50% hypothetical common equity ratio proposed by Mr. Garrett. As such, the Company's proposed common equity ratio of 55.12% is entirely reasonable based on prior Commission action. Hence, the Company's actual common equity ratio conforms with Commission policy, i.e., that the actual, not hypothetical, common equity ratio should be employed.

Q. Does Mr. Garrett provide clear justification for rejecting the Company's actual capital structure and substituting a different capital structure?

A. No. In addition to his proxy group comparisons, Mr. Garrett also performs a "quantitative analysis" that he says supports a 50% debt ratio with a 7.62% cost of equity calculation (see Exhibit DJG-17). There are a variety of deficiencies with his analysis. First, a 7.62% cost of equity is clearly outside the range of reasonable returns for reasons I explained previously. Second, Mr. Garrett never established that his analysis is applicable for UGI Gas in the FPFTY. I have verified the reasonableness of the Company's common equity ratio by considering the historical capital structure ratios for the Gas Group and analysts' forecasts, which influence investor expectations. Historically, the Gas Group has had a 51.5% common equity ratio (see page 5 of UGI Gas Exhibit B). I have also compared the

Company's proposed common equity ratio to that of the Gas Group based upon forecast data widely available to investors from Value Line. Those ratios are**:**

Company	2025-2027
Atmos Energy Corp.	60.0%
Chesapeake Utilities Corp.	60.0%
New Jersey Resources Corp.	42.5%
NiSource Inc.	41.5%
Northwest Natural Holding Company	55.5%
ONE Gas, Inc.	48.0%
South Jersey Industries, Inc.	39.5%
Southwest Gas Holdings, Inc.	51.5%
Spire, Inc.	45.0%
Range:	
High	60.0%
Low	39.5%

Source: The Value Line Investment Survey,

This shows that UGI Gas has a common equity ratio for the FPFTY that is within this range and that its actual capital structure has adequate support.

Q. Does Mr. Garrett's consideration of the Parent Company capital structure play any role in this case?

A. No. Mr. Garrett's consideration of the Company's parent capital structure is also without merit. UGI Corp's capital structure results from its profile of ownership of nonregulated international and domestic propane and domestic midstream business, and regulated utility businesses. As UGI Utilities represents only roughly 25 percent of its profile, UGI Corp's capital structure should not be considered for ratemaking purposes in this case. Moreover, UGI Utilities does not rely on UGI Corporation for its credit profile as it is rated independently by Moody's and Fitch. Excluding consideration of the parent capital structure in this case would be consistent with the Commission's policy in other cases for many years.

COST OF DEBT

Q. Have you updated the Company's cost of debt?

A. Page 3 of Schedule 6 of UGI Gas Exhibit B (Updated), which is attached, provides the Company's cost of debt updated for the FPFTY. It reflects the higher forecast interest rates on the new issues of Senior Notes that will be issued in May, July and October 2022. As shown on page 3 of Schedule 6 UGI Gas Exhibit B (Updated), the embedded cost of long-term debt is 4.30% for the FPFTY. This change increased the embedded cost of debt by 0.32% (4.30% - 3.98%) from my direct testimony. This update produces an overall rate of return of 8.10% ((4.30% x .4488) + 6.17%)). Company witness Hazenstab has adjusted the revenue requirements for this change.[1]

COST OF COMMON EQUITY - DISCOUNTED CASH FLOW (DCF)

Q. The DCF model has been used by Mr. Spadaccio, Mr. Garrett and you as one method to measure the cost of equity. What is your position concerning the usefulness of the DCF method?

A. While the results of a DCF analysis should certainly be given weight, the use of more than one method provides a superior foundation for the cost of equity determination. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing). The simplified DCF model makes the assumption that there is a single constant growth rate, there is a constant dividend payout ratio, that price–earnings multiples do not change, and that the price of stock, earnings per share, dividends

[1] The Company has previously adjusted its interest rates on long-term debt in its rebuttal testimony to reflect changing market conditions. In its 2021 Electric Base Rate Case proceeding at Docket No. R-2021-3023618, UGI Electric lowered its interest rate, which had the effect of reducing its overall rate of return in that proceeding. UGI Electric St. No. 5-R, p. 9.

per share, and book value per share all have the same growth rate. We know from experience that those assumptions are not realistic because the stock market reveals performance that is very different from the assumptions of the DCF.[2] The use of multiple methods provides a more comprehensive and reliable basis to establish a reasonable equity return for AP. The Commission has acknowledged the usefulness of other methods, such as CAPM and Risk Premium, as a check on the reasonableness of the DCF return.

Indeed, the influence of other methods must have an impact on the Commission's attitude toward the DCF model because the Commission's selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone. For example, in the Quarterly Earnings Report at Docket No. M-2021-3028488, the Commission set the DSIC return at 10.20% for the Gas Companies, while the DCF returns were 10.15% using current stock prices and 9.86% using 52-week average stock prices. It is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return. As an apparent check on the reasonableness of the DCF result, the CAPM result was 10.88% for the Gas Company Barometer Group as calculated in the Commission's Quarterly Earnings Report dated September 30, 2021 (Docket No. M-2021-3030045). Indeed, the CAPM and RP methods directly reflect the effect of rising interest rates and are an important indicator of higher equity cost rates. Mr. Spadaccio claims that the DSIC returns that are established in the Quarterly Earnings Report, among other considerations, is designed to reduce regulatory lag and is not a substitute for base rate cases. The DSIC rate is similar to the rate of return on common equity set in base rate cases. This is because the DSIC rate is calculated from the same two models of the cost of equity, i.e., DCF and CAPM, that Mr. Spadaccio used in his direct testimony, and that all of the same risk attributes are contained in those two

[2] The growth rate variables shown on Schedules 8 and 9 of UGI Gas Exhibit B shows that the assumption associated with the simplified DCF model are not reasonable.

models in both proceedings.

Q. What form of the DCF model has been employed in this case?

A. The constant growth form of the DCF model has been used by Mr. Spadaccio, Mr. Garrett, and me.

Q. Do the DCF results proposed by Mr. Spadaccio provide a reasonable representation of the cost of equity?

A. Not in my opinion. I&E Witness Spadaccio concludes that the DCF cost of equity is 9.92% and the CAPM cost rate is 12.13% (I&E Statement No. 2, pages 22 and 25). The Commission has stated that it would consider other methods when other methods showed that the DCF method understated the cost of equity. (Columbia Order, pp. 121 and 131.) It should be noted that I&E's DCF result in this case is also too low for several reasons. First, there have been significant increases in interest rates and inflation since the Columbia decision in the midst of the Pandemic, indicating a higher cost of equity today. Second, I&E's own CAPM result of 12.13% illustrates its DCF result is too low, in contrast to the lower CAPM return in the Columbia case.

The principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any abnormalities. That said, when some of the DCF results for companies in the barometer group are unreasonable on their face, the reliability of the method being used, or the witness' application of that method, must be questioned. As indicated below, DCF results used by Mr. Spadaccio fall into that category:

Company	Average: 52 wk & Spot Yield	+	Growth	=	Total
Chesapeake Utilities	1.67%	+	6.98%	=	8.65%
ONE Gas	3.39%	+	4.63%	=	8.02%

It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with a common equity investment. Yet, each of the companies listed above have DCF returns calculated by Mr. Spadaccio that fail to provide a sufficient spread over the yield of 4.32% on A-rated public utility bonds for April 2022. As I have demonstrated in my direct testimony (UGI Gas Statement No. 6, pages 40-41), the spread between the cost of debt and cost of equity should be 6.75% in this market environment. As such, none of the returns listed above can come close to meeting this standard.

DCF GROWTH RATE

Q. As to the DCF growth component, what financial variables should be given greatest weight when assessing investor expectations?

A. The theory of the DCF holds that (i) the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share with a constant P-E ratio, and (ii) dividend growth will equal earnings growth with a constant payout ratio. Therefore, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be given greatest weight. The reason that earnings per share growth is the primary determinant of investor expectations rests with the fact that the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). It is also important to recognize that analysts' earnings growth rate forecasts significantly influence investor growth expectations. It is for this reason that GDP growth rates submitted by Mr. Garrett are an inappropriate representation of investor growth rate expectations. Moreover, it is instructive to note that Professor Myron Gordon, the foremost proponent of the DCF model in public utility rate cases, has established that the best measure of growth for use in the DCF model are forecasts of earnings per share growth.[3] In Mr. Spadaccio's DCF analysis, he determines the dividend yield by using spot and 52-week stock prices for each company, citing sources in late February or early March, but it is not clear what spot dates were used. (I&E Exhibit No. 2, Schedule 4.)

Q. Please summarize the DCF growth rate analysis performed by Mr. Spadaccio.

A. As shown on page 21 of I&E St. No. 1, Mr. Spadaccio proposes a growth rate of 6.53% based on his review of analysts' projected earnings growth rates. This growth rate is only slightly below the 6.75% growth rate that I determined. Referring to Mr. Spadaccio's growth rates, the 4.63% growth rate for ONE Gas appears to be anomalous. The range of growth rates for other companies is 5.80% to 7.33%. The reason for the low ONE Gas growth rate is a low Yahoo growth rate of 2.90% and no growth rate from Morningstar. Exclusion of ONE Gas growth rate as an anomaly would raise the average growth rate from 6.53% to 6.84%. If he had removed the unduly low growth rate for ONE Gas, his group average growth rate would have been 6.84%, thereby producing a 10.23% (3.39% + 6.84%) DCF return, when excluding the ONE Gas dividend yield as well.

Q. In his testimony, Mr. Garrett does not assemble any growth rates that are specific to his proxy group of gas companies. Does this follow the traditional approach for applying the DCF model?

A. No. The testimony does not follow the normal, or typical processes, for applying the DCF model long used by the Commission and others for determining the return on equity. While Mr. Garrett acknowledges that various sources exist for company-specific growth rates, he

[3] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould. "We have compared the accuracy of four methods for estimating the growth component of the discounted cash flow yield on a share: past growth rate in earnings (KEGR), past growth rate in dividends (KDGR), past retention growth rate (KBRG), and forecasts of growth by security analysts (KFRG)…we have three observations to make. First, the superior performance by KFRG should come as no surprise. All four estimates of growth rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth."

does not present them in his testimony. His approach to looking at GDP growth is certainly alien to all DCF analysis that is familiar to the Commission. On this basis alone, the DCF analysis submitted by Mr. Garrett in this case should be dismissed. I say this because, as I previously explained, Myron Gordon established that analysts' forecast of earnings growth are the correct input for the DCF for each member of the proxy group.

Q. What DCF growth rate did Mr. Garrett actually use in his DCF?

A. The most obvious problem with Mr. Garrett's testimony concerns his development of the growth rate to be used in the DCF model for determining the ROE. In this regard, he advances the proposition that the growth rate for a utility can never exceed the long-term gross domestic product ("GDP") of the country. To the contrary, gas utilities are in a long-term growth phase due to the adoption of 20-to-30-year plans for accelerated replacement of mains and services. As I have explained in my direct testimony, companies, including utilities, can cycle through the growth phases. While Mr. Garrett lists other lower criteria for determining the long-term growth rate, he states in his testimony that he is being "charitable" by using his long-term estimate of GDP growth of 3.8%, OCA Statement No. 2, page 42. This growth rate is well below analysts' projections of earnings growth used by Mr. Spadaccio and me, and it produces a nonsensical DCF cost rate of 6.7%.

Mr. Garrett attempts to downplay the growth phase argument by arguing that growth in rate base due to replacement of aging infrastructure is not growth (OCA Statement No. 2, page 38). The fallacy of his argument rests with replacement of utility plant at the end of its life occurs at much higher costs than those same facilities installed 20, 30 or 40 years ago. This can only be accomplished today by raising extensive amounts of new capital including equity capital. Attraction of new-capital can only be accomplished with supportive regulation, including a reasonable ROE. His argument that analysts' earnings forecasts are not long term are belied by the long-term life of utility plant. Further, his contention that utilities overinvest in rate base to get excessive returns are refuted by the Commission's review and authorization of Long-Term Infrastructure Improvement Plans that are designed to both encourage and monitor such investments.

It seems obvious that imposing a noncompetitive return on replacement of utility facilities by understating the growth rate in the DCF violates the regulatory compact. Utilities accept an obligation to provide reliable and safe service under all situations in exchange for the opportunity to earn a fair return on capital employed. Reducing the ROE during the replacement of aging infrastructure would be counter-productive and place UGI Gas at a disadvantage to other utilities in raising the capital it needs to undertake the replacements. Had he used my growth rate of 6.75% or Mr. Spadaccio's growth rate of 6.53% (or as revised to 6.84%), he would have then produced a DCF return of 9.77% return with the quarterly form of the DCF with my growth rate, or 9.54% (or 9.86% as revised) with Mr. Spadaccio's growth rate. This shows that his DCF return is completely inadequate for the reasons explained above.

Q. Do the DCF growth rates proposed by Mr. Garrett provide a reasonable input in the cost of equity analysis using the DCF model?

A. No. Witness Garrett states that "awarded ROE's are often based primarily on a comparison with other awarded ROEs around the country," but he offers no support for or citation for this conclusion. (OCA Statement No. 2, page 16.) In contrast, the ROE in the Columbia case in 2021 was based specifically on the I&E DCF using analysts' projections of earnings to determine the DCF growth rate. Finally, Mr. Garrett admits that many utility analysts, as well as public utility comimssions, use financial analysts' projected growth rates in estimating the ROE. Yet, he offers no evidence that any commission has accepted his calculation of the growth rate. (OCA Statement No. 2, page 42.)

Mr. Garrett indicates that his method for analyzing the growth rate component rests on: (i) nominal GDP, (ii) real GDP, (iii) inflation, and (iv) the risk-free rate. There are many problems with his approach. First, the combination of the real GDP growth and inflation equals nominal GDP, i.e. (1.018) * (1.020) = (1.0380 -1) = 3.8%. Hence, two of his input variables are double counted when he separately considers nominal GDP growth. Second, the risk-free rate provides no guide of the growth that a company can realize in its earnings. Earnings growth occurs through revenue growth, net of: O&M, depreciation, taxes, and interest. None of these factors are addressed with the risk-free rate of return. Third, Mr. Garrett is essentially developing a generic growth rate that would apply to any, or all, companies, whether they are regulated or non-regulated companies. However, each company has a unique company-specific growth rate. His approach is simply incompatible with the basic concept of the DCF, where future cash flows for each company are systematically related to one another by a constant growth rate that represents a basic tenant of the single-stage DCF. It is also incompatible with the use of the growth rates of a comparable barometer group of companies to meet the requirement that a utility is to be permitted to earn a return equal to comparable companies. The DCF equation is P = D / (k-g). Mr. Garrett's growth rate does not fit within this equation.

LEVERAGE ADJUSTMENT

Q. Please respond to Mr. Spadaccio's criticism of your leverage adjustment.

A. Mr. Spadaccio offers three reasons for not making a leverage adjustment. First, Mr. Spadaccio notes that the credit rating agencies assess financial risk in terms of a company's booked debt obligations in their analysis of the creditworthiness of a company (see I&E Statement No. 2, page 38). I agree. But this has nothing to do with my leverage adjustment. The credit rating agencies do not measure the market required cost of equity for a company. The credit rating agencies are only concerned with the interests of lenders. They are judging risk associated with a company's ability to make timely payments of principal and interest. Hence, they are not concerned with the cost of equity or how it is applied in the rate-setting context. While Mr. Spadaccio's observation is correct, it has no relevance to my leverage adjustment.

Q. Second, Mr. Spadaccio also questions your leverage adjustment by reference to prior Commission orders. Please comment.

A. Mr. Spadaccio points to several decisions where the Commission declined to make a leverage adjustment (see I&E Statement No. 2, page 39). The fact that the Commission declined to use the leverage adjustment in the Aqua Pennsylvania case cited by Mr. Spadaccio does not invalidate its use. Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance. Just like an increment for management performance is not recognized in all rate cases, so too the Commission seems to be taking a similar approach to the leverage adjustment. As to the City of Lancaster decision, the situation there was quite different than the leverage adjustment that I propose in this case. Lancaster proposed a leverage adjustment to the cost of equity measured with the Hamada formula and applied it to the DCF result, the Risk Premium result, and the CAPM. While the Hamada formula plays a role in the CAPM, it is not applicable to the DCF or the Risk Premium measures of the cost of equity. Hence, this distinguishes the City of Lancaster approach to the leverage adjustment from mine in this case. As to the UGI – Electric Division case, there the Commission granted a management performance increment rather than a leverage adjustment when arriving at a 9.85% equity return. And for Columbia, the company accepted the ALJs determination of the allowed return, which was 9.86%. Thus, Columbia chose not to argue the leverage adjustment in Exceptions to the Commission. However, based upon the current inputs to the DCF that indicated a low result, the Commission should now consider using the leverage adjustment, just as it did previously when the DCF was suggesting unusual results. In the PECO - gas rate case, the Commission arrived at a 10.24% return without the leverage adjustment, because that return was already deemed to be on the higher side and no additional adjustment was warranted.

Q. Third, Mr. Spadaccio argues that investors base their decisions on the book value debt and equity ratios for regulated utilities. Please respond.

A. Mr. Spadaccio contends that information presented to investors (see page 41 of I&E Statement No. 2), such as that included in the Value Line reports, argues against my leverage adjustment because investors base their investment decisions on book value. However, the Value Line reports clearly show the market capitalization of each company in his barometer group. This means that investors are well aware of the market capitalization of the gas utility stocks that Mr. Spadaccio relies upon for his analysis of the cost of equity. More importantly, I fundamentally disagree that investors base their decisions on book values. To the contrary, it is the future cash flows that investors expect to realize that determines the price they are willing to pay for a share of common equity. Stated differently, investors are concerned with the return that will be earned on the dollars they invest (i.e., their market price) and not some accounting value of little relevance to them. The financial risk associated with the book value capital structure is different from the market value of the capitalization. I clearly demonstrate this point on Schedule 10 of UGI Gas Exhibit B. Hence, the observation of Mr. Spadaccio is misplaced because I have clearly shown the difference in financial risk and that risk difference must be taken into account when arriving at an equity return that is applicable to the weighted average cost of capital using book value weights.

Q. Mr. Garrett criticized the leverage adjustment that you propose to account for the divergence of market capitalization and book value capitalization. Please comment.

A. At pages 44-48 of OCA Statement No. 2, Mr. Garrett never really refutes my leverage adjustment. Indeed, he says that I misapplied the Hamada formula leverage adjustment approach. First, in the DCF approach, I did not use the Hamada formula, but rather I used the Modigliani & Miller approach. Second, at page 47 of OCA Statement No. 2, Mr. Garrett claims that the Hamada formula generates an unlevered beta of 0.53. But what I have shown is that the correct unlevered beta is 0.54 (see page 40 of UGI Gas Statement No. 7). The reason for the difference is that I correctly use the market capitalization for my calculation, including the market value of debt, and Mr. Garrett did not because he used the book value capital structure ratios of UGI Gas. Indeed, there, Mr. Garrett used the actual capital structure ratios of UGI Gas, rather than the hypothetical ratios he proposes which is an inconsistent analysis.

COST OF COMMON EQUITY - CAPITAL ASSET PRICING MODEL

Q. Do you have concerns regarding Mr. Spadaccio's and Mr. Garrett's applications of the CAPM?

A. Yes. Mr. Spadaccio's CAPM analysis understates the cost of equity for a number of reasons: (i) his use of the yield on 10-year Treasury notes, (ii) his failure to use leveraged adjusted betas, and (iii) his failure to make a size adjustment. Mr. Garrett uses an inappropriate 30-day average yield on 30-year Treasury bonds, a beta that is not leverage adjusted, an unrealistic market risk premium, and ignores the size adjustment. He therefore proposes a totally unrealistic 7.2% CAPM result This compares with my CAPM of 13.55%, Mr. Spadaccio's CAPM of 12.13%, and the Quarterly Earnings Report CAPM of 10.88%. With regard to Mr. Spadaccio's CAPM analysis, which produces a 12.13% cost rate, it can be argued that he has understated the risk-free rate. On Schedule 8 of I&E Exhibit 2, he uses a projected 10-year treasury note yield from Blue Chip in December 2021 and February 2022, producing a 2.35% risk-free rate. Recently the actual 10-year treasury bond has been yielding around 3.0%, with many Fed funds rate increases forthcoming.

Q. How does the use of the yield on 10-year Treasury notes compare with yields on longer-term Treasury bonds?

A. The Blue Chip report dated April 29, 2022 shows this comparison. For the first quarter of 2022, the gap was 0.31% (2.25% - 1.94%) between the yields on 30-year and 10-year Treasury obligations. For the period 2023-2027, that gap is projected at 0.50% (3.4% -

2.9%) according to the December 1, 2021 Blue Chip. This shows a systematic understatement of Mr. Spadaccio's CAPM returns. This understatement can be traced to extraordinary monetary policy actions taken by the FOMC to deal with the recession that followed the onset of the Pandemic. Shorter-term rates, such as 10-year notes, respond more to the policy initiatives of monetary officials, while long-term rates, such as 30-year bonds, are more a reflection of investor sentiment of their required returns. For this reason, long-term rates, such as those revealed by 30-year Treasury bonds, should be used to measure the risk-free rate of return. Accordingly, use of 30-year Treasury bond projected yields would increase his CAPM result. Use of shorter-term rates, such as Mr. Spadaccio's 10-year Treasury Notes yields, are more susceptible to Fed policy actions.

Q. How has Mr. Spadaccio understated the risk-free rate of return?

A. The support for his risk-free rate of return is shown on his Schedule 8 of I&E Exhibit No. 2. There, he incorrectly gives the same weight to the yield on 10-year Treasury notes for the second quarter of 2022 as he does for the entire five-year period from 2023 through 2027. This approach leads to a seriously understated risk-free rate of return. Even if 10-year rates are used, it is necessary to correct the weights assigned to the forecast data presented by Mr. Spadaccio. I have revised his forecast below, based upon Blue Chip. Moreover, Blue Chip provides higher yields on Treasury obligations as the forecasts are extended into the future.

The resulting risk-free rate of return is 2.8% using the yield on 10-year Treasury Notes and 3.3% using the yield on 30-year Treasury Bonds.

Year	10-Year Treasury Yield	30-Year Treasury Yield
2022	2.1%	2.4%
2023	2.4%	2.9%
2024	2.8%	3.3%
2025	3.1%	3.6%
2026	3.2%	3.7%
2027	3.2%	3.7%
Average	2.8%	3.3%

Q. How should these results be used in the CAPM?

A. The risk-free rate of return should be calculated with the data that I present above. The size adjustment of 1.02% must also be incorporated into the CAPM. I have corrected Mr. Spadaccio's CAPM as indicated below using those inputs and the forecast yield on 10-year Treasury bond shown above:

	Rf	+	*β*	(	*Rm*	-	*Rf*	) +	*size*	=	*K*
Gas Group	2.80%	+	0.84	(	13.99%	-	2.80%	) +	1.14%	=	13.34%

Q. Mr. Spadaccio questions the need to adjust the CAPM results for size differences. Please comment.

A. As a preliminary matter, it is noteworthy that CAPM provides compensation solely for systematic risk, and that the size of the Gas Group must be considered separately. As I indicated with the data presented on Schedules 2, 3 and 4 of UGI Gas Exhibit B, the gas utilities are small as they are just 16% of the size of the electric and gas utilities that comprise the S&P Public Utilities. Indeed, recent Federal Energy Regulatory Commission ("FERC") orders specifically prescribe an adjustment to the CAPM due to the size of an enterprise.[4] Mr. Spadaccio's arguments revolve around the purported distinction between

[4] *See, e.g.*, Association of Businesses Advocating Tariff Equity, 171 FERC ¶61,154 (May 21, 2020).

regulated utilities and unregulated industrial companies (see page 45 of I&E Statement No. 2). However, the Wong article that he relies upon was authored twenty (20) years ago, and employed data going back into the 1960s. Enormous changes have occurred in the industry since the 1960s that have fundamentally changed the utility business. The Wong article also noted that betas for the non-regulated companies were larger than the betas of the utilities. This, however, is not a revelation, because utilities continue to have lower betas than many other companies. This fact does not invalidate the additional risk associated with small size.

The Wong article further concludes that size cannot be explained in terms of beta. Again, this should not be a surprise. Beta is not the tool that should be employed to make that determination. Indeed, beta is a measure of systematic risk and it does not provide the means to identify the return necessary to compensate for the additional risk of small size. In contrast, the famous Fama/French study (see "The Cross-Section of Expected Stock Returns," The Journal of Finance, June 1992) identified size as a separate factor that helps explain returns.

Q. How does size affect the financial performance of a small company?

A. Examples of the financial consequences of external factors that can influence the financial performance of a small company include loss of a large customer and the effect of unexpected changes in expense.

Q. In the recent Gas Division rate case for PECO Energy (Docket No. R-2020-3018929), the Commission declined to make a size adjustment to the CAPM. Should the size adjustment be considered here?

A. Yes. In that case, the ALJs and Commission concluded the adjustment for size was not necessary in utility rate regulation. In this case, it is worthy to note that the beta measure of systematic risk does not account for the additional risk associated with small size, either for a non-regulated firm or a public utility. In addition, the studies that I have relied upon for the size adjustment utilized market-wide evidence that included public utilities. Likewise, the FERC has incorporated the size adjustment into its CAPM analysis. For these reasons, the Commission should revisit the propriety of including a size adjustment here.

Q. At pages 62-64 of OCA Statement No. 2, Mr. Garrett also challenges the adjustment that you made to the results of the CAPM for the size of the Gas Group. Please respond.

A. A size adjustment is necessary because the financial impact of changes in specific dollar amounts of revenues and costs have a magnified influence on a small company because there are fewer dollars over which those revenues or costs can be spread.

Q. Mr. Garrett has also performed a CAPM calculation in addition to his DCF analysis. Are the results of his CAPM useful in setting the Company's equity return in this case?

A. No. There are a variety of problems with Mr. Garrett's CAPM approach that makes it not useful in this case. He makes CAPM calculations that produce results of 7.2%, which on its face is simply not credible. This is shown by the Commission's Quarterly Earnings Report that produces a CAPM return of 10.88% for the Gas Company barometer Group that exceeded substantially the DCF return. First, Mr. Garrett uses a backward looking 2.40% yield on 30-year Treasury bonds. A 30-day historical average period is not compatible with the Commission's use of forecast Treasury yields (see UGI Utilities, Inc. - Electric Division at Docket No. R-2017-2640058, Order Entered October 25, 2018). Second, the 5.5% equity risk premium ("ERP") selected by Mr. Garrett is completely off the mark. The principal departure from the normal input is in his calculation of the ERP. He rejects the use of both historic ERPs and projected ERPs calculated based on projected market returns. Instead, he reviews “Expert Surveys” and his own calculations. He then uses the 2021 survey conducted by IESE Business School, indicating that it provides the highest ERP of 5.5 %. There is no evidence that investors use this source of the ERP in their CAPM calculations. Furthermore, the implied total market return using Mr. Garrett's final inputs is just 7.90% (2.40% + 5.5%), which is clearly incompatible with actual stock market returns of 18.40% in 2020, 28.71% in 2021, and 12.33% on average for the past 96 years (1926-2021).

COST OF COMMON EQUITY - RISK PREMIUM ANALYSIS

Q. Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity, which must be higher than the cost of debt in recognition of the higher risk of equity (see UGI Gas Statement No. 6, pages 38-41). So, while Mr. Spadaccio and Mr. Garrett decline to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk. It is particularly useful when investors expect changes in the cost of debt prospectively, which is currently the expectation of investors, as I have explained above and in UGI Gas Statement No. 6, pages 39-40. Indeed, the Risk Premium approach provides for direct reflection of prospective interest rates in the model and therefore should be given weight in determining the equity cost rate in this case.

Q. Please respond to Mr. Garrett’s criticisms of your Risk Premium approach.

A. While Mr. Garrett declines to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk. In fact, it is precisely because investors consider the results of other methods that they too should be used in addition to the DCF in the development of the cost of equity in this proceeding. As I explained in my direct testimony, we are facing the prospect of increasing interest rates for the future and the market has increased yields on debt instruments. I incorporated the trend toward higher interest rates when I developed my Risk Premium cost of equity of 10.50% (3.75% interest rate on A-rated public utility bonds + 6.75% equity risk premium). The recent increase in interest rates would support a higher rate today.

Q. What does Mr. Spadaccio say about your Risk Premium analysis?

A. Mr. Spadaccio makes the unfounded assertion that the Risk Premium and CAPM methods should only be used as a comparison to the results of the DCF method because they do not carry over from the investment decision-making process to the utility rate setting process (see page 18 of OCA Statement No. 2). In fact, it is precisely because investors consider the results of other methods that they too should be used in addition to the DCF in the development of the cost of equity in this proceeding. Mr. Spadaccio's assertion that the Risk Premium method does not measure the current cost of equity as directly as the DCF is similarly without foundation. As I explained in my direct testimony and earlier in this rebuttal testimony, we are facing the prospect of increasing interest rates for the future. I incorporated the trend toward higher interest rates when I developed my Risk Premium cost of equity of 10.50%. Hence, my Risk Premium cost rate is fully responsive to changing market fundamentals and the credit quality of the Gas Group.

COST OF COMMON EQUITY - COMPARABLE EARNINGS APPROACH

Q. Please respond to the criticism of the Comparable Earnings approach.

A. The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital.

The Comparable Earnings approach satisfies the comparability standard established in the *Hope* case. In addition, the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets. Moreover, in a 1994 study that addressed the ROE issue, John Olson (then with Merrill Lynch) established that ROEs from non-regulated companies provide better assessment of investor requirements than those available for regulated utilities.[5]

MANAGEMENT PERFORMANCE

Q. Both Mr. Spadaccio and Mr. Garrett oppose any recognition for management performance in the determination of the return on equity. Mr. Spadaccio and Mr. Garrett assert that UGI Gas has only done what it is required to by law. How do you respond?

A. As I stated in my direct testimony, I believe UGI Gas has performed in an exemplary manner, as explained by UGI Gas Witness Brown, and that performance should be recognized in this case. Mr. Spadaccio simply disagrees, without addressing any of the items highlighted by Mr. Brown as examples of UGI Gas's excellent performance. Mr. Garrett's position regarding management performance is that the models of the cost of equity already incorporate management effectiveness. In each case, neither Mr. Spadaccio nor Mr. Garrett has shown that UGI Gas is not entitled to some form of management performance recognition by the Commission. Mr. Brown's testimony has established that

[5] "Natural Gas: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

the Company's management performance warrants recognition by the Commission.

Q. Mr. Garrett also criticizes your addition of a management performance adjustment, arguing that you have proposed such an adjustment in each rate case in Pennsylvania since 2015. Please comment.

A. Mr. Garrett misperceives my role with respect to management performance adjustments to equity. As I have made clear in this case, and in each of the cases identified by Mr. Garrett, I do not make an independent assessment of management performance of each utility. Other company witnesses, such as Mr. Brown in this case, present evidence in support of management performance. Mr. Brown discusses this issue further in his rebuttal testimony.

FIRM-SPECIFIC BUSINESS RISK

Q. Is Mr. Garrett's position correct that investors should not be compensated for business risk because use of a diversified portfolio eliminates business risk. OCA St No.2, p. 65.

A. No. He is incorect to argue that "[n]either [DCF or CAPM] model includes an input for business risks due to the well- known truth that investors do not expect a return for such risks." (OCA Statement No. 2, page 66.) It is well accepted that higher returns are expected from more-risky businesses. Stated another way, companies with higher returns are associated with the more-risky members of the barometer group and lower returns go with the less risky ones. Through diversification, the barometer group has an average risk profile. This is important because a business risk adjustment is necessary for the higher risks of UGI Gas as compared to the barometer group companies as a whole. With higher business risk, a company, including utilities, would offset higher business risk with a lower debt ratio.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. Spadaccio and Mr. Garrett understate the cost of common equity for UGI Gas. This is particularly true for Mr. Garrett's proposal. In an environment of prospectively higher interest rates and Company-specific risk factors, an opportunity to earn a cost of equity of 11.20% is reasonable for UGI Gas.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit B

Schedule 6, Pages 3 and 4

(UPDATED)

UGI Utilities, Inc.
Calculation of the Embedded Cost of Long-Term Debt
Estimated at September 30, 2023

Series	Date of Maturity	Principal Amount Outstanding ($000)	Percent to Total	Effective Cost Rate [1]	Weighted Cost Rate
Medium Term Notes					
6.500%	08/15/33	$ 20,000	1.35%	6.56%	0.09%
6.133%	10/15/34	20,000	1.35%	6.19%	0.08%
Senior Notes					
6.206%	09/30/36	100,000	6.74%	6.32%	0.43%
4.980%	03/26/44	175,000	11.79%	5.00%	0.59%
2.950%	06/30/26	100,000	6.74%	3.92%	0.26%
4.120%	09/30/46	200,000	13.48%	5.01%	0.68%
4.120%	10/31/46	100,000	6.74%	4.28%	0.29%
4.550%	02/01/49	150,000	10.11%	4.58%	0.46%
3.120%	04/16/50	150,000	10.11%	3.15%	0.32%
1.590%	06/15/26	100,000	6.74%	1.73%	0.12%
1.640%	09/15/26	75,000	5.06%	1.75%	0.09%
4.744%	05/31/52	90,000	6.07%	4.78%	0.29%
4.003%	07/31/27	118,750	8.00%	4.14%	0.33%
4.744%	10/31/52	85,000	5.73%	4.78%	0.27%
Total Long-Term Debt		$ 1,483,750	100.00%		4.30%

Notes: [1] As calculated on page 4 of this schedule.

Source of Information: Company provided data

UGI Utilities, Inc.
Calculation of the Effective Cost of Long-Term Debt by Series

Series	Date of Issue	Date of Maturity	Average Term in Years (1)	Principal Amount Issued	Premium/ Discount & Expense	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate (2)
					($000)			
Medium Term Notes								
6.500%	08/14/03	08/15/33	30	$ 20,000	$ 150	$ 19,850	99.25%	6.56%
6.133%	10/14/04	10/15/34	30	20,000	150	19,850	99.25%	6.19%
Senior Notes								
6.206%	11/14/06	09/30/36	30	100,000	1,485	98,515	98.52%	6.32%
4.980%	03/26/14	03/26/44	30	175,000	642	174,358	99.63%	5.00%
2.950%	06/30/16	06/30/26	10	100,000	7,949	92,051	92.05%	3.92%
4.120%	09/30/16	09/30/46	30	200,000	27,366	172,634	86.32%	5.01%
4.120%	10/31/16	10/31/46	30	100,000	2,710	97,290	97.29%	4.28%
2.998%	10/31/17	10/31/22	4.6875	125,000	674	124,326	99.46%	3.12%
4.550%	02/28/19	02/01/49	30	150,000	713	149,288	99.53%	4.58%
3.120%	03/19/20	04/16/50	30	150,000	835	149,165	99.44%	3.15%
1.590%	06/15/21	06/15/26	5	100,000	680	99,320	99.32%	1.73%
1.640%	09/15/21	09/15/26	5	75,000	390	74,611	99.48%	1.75%
4.744%	05/31/22	05/31/52	30	90,000	450	89,550	99.50%	4.78%
4.003%	07/31/22	07/31/27	5	125,000	750	124,250	99.40%	4.14%
4.744%	10/31/22	10/31/52	30	85,000	425	84,575	99.50%	4.78%

Notes: (1) Determined by taking into account the effect of the annual sinking fund requirements which are met by the retirement of principal which reduce the term of each issue.
(2) The effective cost for each issue is the yield to maturity using as inputs the average term of issue, coupon rate, and net proceeds ratio.

Source of Information: Company provided data

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 8-R

Rebuttal Testimony of
Sherry A. Epler

Topics Addressed:	**Test Year Sales and Revenues** **Revenue Allocation and Rate Design** **Tariff Charges**

Dated: May 17, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 8, on January 28, 2022.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the following direct testimony submitted by the Bureau of Investigation and Enforcement ("I&E"), the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), and the Commission on Economic Opportunity ("CEO"): (1) I&E Statement No. 4, the direct testimony of Ethan H. Cline; (2) OCA Statement No. 3, the direct testimony of Jerome D. Mierzwa; (3) OCA Statement No. 4, the direct testimony of Roger D. Colton; (4) OSBA Statement No. 1, the direct testimony of Robert D. Knecht; (5) CAUSE-PA Statement No. 1, the direct testimony of Harry S. Geller; and (6) CEO Statement No. 1, the direct testimony of Eugene M. Brady.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Gas Exhibits SAE-1R through SAE-4R.

II. TEST YEAR SALES AND REVENUE

Q. I&E witness Cline disagrees with the Company's claimed present rate revenue for the fully projected future test year ("FPFTY"). (I&E St. No. 4, pp. 6-22.) Please summarize his overall recommended adjustment and the reasons Mr. Cline is supporting it.

A. Mr. Cline believes the Company's present rate revenue in the FPFTY has been understated and recommends two adjustments: (1) an adjustment concerning the rate class R/RT heating customer usage decline reflected in the FPFTY, which, according to him, was projected beyond the end of the FPFTY; and (2) an adjustment related to the overall regression analysis performed by UGI Gas to project usage per R/RT heating customer to determine sales volumes. Therefore, he recommends that present rate revenues be increased as outlined in detail below.

Q. As to his first adjustment related to the projected Rate Class R/RT heating customer usage decline, could you please explain his disagreement with the Company's position?

A. Yes. Mr. Cline asserts that "the Company's analysis projects residential heating customer usage declines through March 2024, which is six months beyond the FPFTY." (I&E St. No. 4, p. 9.) With the Company's use of a "mid-year convention" to capture the full annualized impacts related to customer conservation activities through September 30, 2023, Mr. Cline believes that UGI Gas "inappropriately misaligns data for determination of a revenue requirement and affords the Company a greater revenue increase than is appropriate for its FPFTY claim." (I&E St. No. 4, pp. 9-11.) According to Mr. Cline, "a customer's installation of a high efficiency heating system in February or March will not produce lower gas sales until a full year after the end of the FPFTY." (I&E St. No. 4, pp. 11-12.) Therefore, he recommends that the average usage per R/RT customer be increased by 0.1307 Mcf per customer per year, which results in an increase of gas volumes of 77,061 Mcf and present distribution rate usage revenues by $316,752. (I&E St. No. 4, pp. 12-13.) He also observes that there would be corresponding increases in purchased gas revenues and expenses of $413,399 and impacts on the projected surcharge revenue. (I&E St. No. 4, p. 14.)

Q. Do you agree with Mr. Cline's position on the projected Rate R/RT residential heating customer usage decline?

A. No. Contrary to Mr. Cline's assertions, the Company's method does not incorporate post-FPFTY usage decline. Rather, it assesses the impact of customer usage reducing measures that are already in place prior to the end of the FPFTY, and simply annualizes that impact to reflect end of FPFTY conditions. Without this adjustment, Rate R/RT usage per customer would not be appropriately annualized in accordance with permitted adjustments that allow end-of-FPTFY conditions to be included for ratemaking.

Specifically, the Company applied a mid-point convention to evaluate its monthly residential use per customer regression results in order to capture the full annualized impacts related to customer conservation activities through the FPFTY end (*i.e.*, September 30, 2023). Because September 30, 2023 is the middle of the annual period ending March 31, 2024, the Company must project monthly use through the end of March 31, 2024 to develop an annualized value for use per customer. Thus, the sum of monthly use values for the 12-month period ending March 31, 2024, would represent the annualized rate of use for those customers existing only "as of" September 30, 2023. In discovery, the Company provided I&E with a detailed explanation on the use of a mid-point convention to capture the impacts of appliance replacements over time in a manner which would properly annualize residential use per customer. (*See* UGI Gas Exhibit SAE-1R.)

By comparison, if the Company utilized the sum of monthly regression results for the 12-months ending September 30, 2023, as Mr. Cline suggests, the impact of residential customer conservation measures - such as furnace replacements completed during the summer of 2023, or more specifically those made prior to the end of the FPFPTY that are in place but not yet measured via observed and billed usage would not be appropriately annualized and would not reflect end of FPFTY conditions. In effect, Mr. Cline's recommendation would reflect the mid-point of the FPFTY and produce a projection that is for those customers existing "as of" March 30, 2023, and not the end of the FPFTY. This approach would overstate the residential usage per customer at the end of the FPFTY because annualized use per customer is continuing to decline throughout the year. In using a "fully projected" future test year method that assesses use per customer impacts through September 30, 2023 for equipment and measures installed as of that date, the Company has appropriately applied an analysis, which measures the impacts related to the installations, but only for installations during the FPFTY period and not beyond; a known and measurable approach that is appropriate for ratemaking. Based on the foregoing, Mr. Cline's adjustment to present rate revenues related to Rate R/RT heating customer usage decline should be rejected.

Q. As to Mr. Cline's second adjustment, what are his reasons for opposing the Company's regression analysis?

A. Mr. Cline disagrees with UGI Gas's use of 18 years of data to project the 87.8 Mcf annual usage for the R/RT heating customers. (I&E St. No. 4, p. 15.) According to Mr. Cline, "older usage data is less indicative of recent trends," and "it is not reasonable to allow less significant older data from a time period when the service territory was not as saturated with usage reducing appliances to influence the results of the projection of future usage." (I&E St. No. 4, pp. 15-16.) He also observes that a 15-year time period was used in prior UGI Gas base rate cases. (I&E St. No. 4, pp. 16-18.) Therefore, Mr. Cline recommends a 15-year time period from October 2006 through September 2021 for the residential usage per customer regression analysis. (I&E St. No. 4, p. 16.) His recommendation would increase the projected average usage per R/RT customer for the FPFTY to approximately 90.2576 Mcf, increase gas volumes by 1,440,867 Mcf, and increase present rate usage revenue by $5,922,539. (I&E St. No. 4, pp. 19-20.) It also would increase purchased gas revenue and expenses by $7,729,631 and impact the projected surcharge revenue. (I&E St. No. 4, pp. 20-21.) Finally, Mr. Cline notes that if the Commission accepts this second adjustment, concerning the regression analysis time period, then his first adjustment would not be added in separately because it is already a part of the regression analysis adjustment. (I&E St. No. 4, p. 15.)

Q. Do you agree with Mr. Cline's proposed adjustment concerning the Company's regression analysis?

A. No. Mr. Cline makes several assertions in support, including: (1) a 15-year time period is consistent with the reasons UGI Gas described for utilizing a multi-year regression period; (2) the 15-year time period is consistent with the time period used for the Company's weather normalization adjustment; (3) the Company has supported the use of 15-year time period for its regression analysis in its previous cases; and (3) his belief that usage and temperature data older than 15 years is not representative of recent usage trends on which to base the usage projection. *See* I&E Statement No. 4, page 16.

While I do agree that Mr. Cline is attempting to be consistent with the reasons the Company described for utilizing a multi-period regression, I do not agree with his other points. Specifically, while Mr. Cline notes that his recommendation to use a 15-year time period is consistent with the time period used for the Company's weather normalization adjustment, the determination of these two variables, weather and use per customer, need to be evaluated individually. The key goal in such evaluation is to determine which methodology supports the most accurate determination of each separately for use in ratemaking. For example, if new appliance technology were revealed tomorrow that doubled furnace efficiency and decreased appliance use by half, use per customer would be most appropriately assessed based on the rate of consumer adoption of such technology. If it could be adopted "overnight," projected heating use per customer for the FPFTY period would be cut in half (and the Company's use of a 15-year regression to determine trends would no longer hold accurate). This change in use per customer would not impact on how normal weather is defined because the technology would not be changing weather. While this example is admittedly extreme to demonstrate the point, in the end, the Company would still be utilizing a 15-year period for determining normal weather until it determined another driving need to modify that approach; it would not then say as a result of the new furnace efficiencies that normal weather now should be redefined.

Thus, while one variable (use per customer) may be dependent on the other (heating degree days) for quantification, the reverse is not true (heating degree days are not dependent on use per customer). Thus, the two factors require independent assessment which can then be utilized to support proper ratemaking design, claims and conclusion.

As to Mr. Cline's next point that the Company has supported the use of 15 years before, that was a result of the Company acknowledging data availability as a limiting factor at the time of that individual case. Specifically, in UGI Gas's 2019 rate case, the Company used 15 years of data in its Rate R/RT residential use per customer analysis due to the fact that, at that time, the 15-year period represented the historical time period for which the Company had common data across all three of the former UGI Gas utility rate districts: UGI South Rate District, UGI North Rate District, and UGI Central Rate District. October 2003 was the beginning of that dataset and, thus, the Company used "all available" historical data at that time. In fact, the use of non-common data, or differing periods by rate district, would have resulted in skewed results and, therefore, could not be used.

In UGI Gas's 2020 rate case, the Company extended that 15-year period for an additional year of data which was collected since the time of the 2019 case, thus forming the use of a 16-year analysis of residential heating use in that case. UGI Gas has now done the same update in this current UGI Gas 2022 rate case to extend the dataset for an additional two additional years to September 30, 2021, for a total data set of "all available" data - now 18 years. This approach follows the Company's historical attempt to use all available data to perform Rate R/RT residential use per customer regressions in an effort to smooth out transient aberrations that may occur year-to-year for various reasons and best capture long-term trends influencing use per customer. Therefore, the same "all available" approach has been used by the Company in the past several base rate cases, as summarized below.

Case	Regression Time Period	Rate R/RT Source Data Used
2022 UGI Gas	18 years	All available common years across former rate districts; October 2003 forward
2020 UGI Gas	16 years	All available common years across former rate districts; October 2003 forward
2019 UGI Gas merger	15 years	All available common years across former rate districts; October 2003 forward

In summary, Mr. Cline claims that the Company is changing its methodology for Rate R/RT where it supported the use of a 15-year regression in previous cases. However, as explained above, the Company has only expanded the dataset used in the analysis to comport with the Company's view that the use of "all available" data is most appropriate for ratemaking purposes in forecasting residential use per customer trends, for reasons as noted above. The Company has remained consistent in looking to use all available historic data in the regression analyses through its recent base rate case filings as demonstrated in the above table.

Lastly, Mr. Cline supports a 15-year period based on his belief that usage and temperature data older than 15 years is not representative of recent usage trends on which to base the usage projection as they represent “stale data.” *See* I&E Statement No. 4, page 19. The Company is not aware of a regulatory “stale” standard that is appropriate for ratemaking and thus does not agree with Mr. Cline’s assertion. In review of UGI Gas Exhibit SAE-3(a), the “stale data” apparently is related to a downward trend in usage during the time period Mr. Cline suggests be excluded. However, UGI Gas Exhibit SAE-3(a) also contains several trends which are upward in magnitude, specifically, in the 2010-2011, 2012-2013 and 2016-2018 time periods. However, Mr. Cline does not call these out as periods which may also be stale and requiring exclusion in similar fashion to the downward trend he has excluded (he certainly could have said anything beyond 5 years is stale data as readily as beyond 15.) Indeed, it is the Company’s view that a longer period of time serves to balance short term variability in long term trends, as demonstrated through the years shown in UGI Gas Exhibit SAE-3(a), and supports the use of larger data periods. In short, Mr. Cline’s approach appears only intended to establish a result which would increase Rate R/RT residential heating use per customer and should be rejected.

Q. Has UGI Gas utilized data for a period of 18 years or greater in the past based on “all available” data?

A. Yes. In UGI Gas’ 2016 rate case, UGI Gas (former South Rate District) based its Rate R/RT residential heating use per customer regression on a period of nearly 21 years of data.

At that time, it represented all available data. *See* Docket No. R-2015-2518438. I would note as well that the residential use per customer regression analyses presented by the Company have always been reviewed for, and have maintained, statistical significance. Statistical significance is discussed in more detail below.

Q. Have you discovered any other problems with Mr. Cline's recommended 15-year approach?

A. Yes. In response to Company's discovery, I&E provided the workpapers in support of its claimed 15-year approach: R-2021-3020218 (UGI Gas BRC) I&E Exhibit No 4 Sch 3 FINAL.xlsx. Upon review however, on the tab labeled "15-yr regrn results," the "SUMMARY OUTPUT" of the regression that Mr. Cline bases his recommended adjustment upon is clearly one based on 61 monthly observation points, or a period of just 5 years and 1 month. See line 8 "Observations" value of 61 (months). Thus, I am not certain if Mr. Cline intended to use a 15-year approach as stated in his testimony, or a 5 year and 1 month approach, as found within his workpapers. If the former, Mr. Cline has not provided supporting evidence to his adjustments. If the latter, Mr. Cline has provided support, but his support demonstrates it should not be considered in lieu of the Company's analysis.

Q. Why should the support provided by Mr. Cline's workpapers not be considered in lieu of the Company's analysis?

A. Mr. Cline's regression does not demonstrate statistical significance for all regression variables. In the field of statistics, P-value is a measure of statistical significance and has been summarized as follows:

> Statistical significance, calculated as a P-value, is another statistical method of evaluating the possible role of chance. The P-value measures the likelihood that one would see the observed association even in the absence of a true association. The lower the P-value, the less likely the observed result is due to chance alone. In other words, as the P-value gets smaller and smaller, the data is less and less consistent with the "null hypothesis": the hypothesis that there is no association between the factor and the outcome.
>
> Traditionally, P-values are termed "statistically significant" when they are less than 5 percent ($P < 0.05$) and confidence intervals (or "level of confidence") are set at 95%. A confidence interval provides more information for evaluating an epidemiology study than a P-value. A confidence interval provides information about the precision of the estimate of the association and how well other estimates of the association would be supported by the data.[1]

Therefore, a well-established standard is that a P-value less than 0.05 means that the value is statistically significant, whereas a P-value greater than 0.05 means that the value is not statistically significant. Relevant here, a review of the P-value results of Mr. Cline's regression equation variables shows the following:

Variable	*P-value*
Intercept	1.16327E-07
X Variable 1	0.197751367
X Variable 2	2.07643E-17
X Variable 3	0.99328517

In the above table, the "X Variable 1" equates to the variable of "Lagged Monthly Heating Degree Days", "X Variable 2" equates to the variable of "Monthly Heating Degree Days," and "X Variable 3 equates to the variable of "Weighted Time Trend". See UGI Gas SDR-

[1] *Magistrini v. One Hour Martinizing Dry Cleaning*, 180 F. Supp. 2d 584, 592 (D.N.J. 2002), *affirmed*, 68 Fed. Appx. 356 (3d Cir. 2003).

RR-10 and SDR-RR-11 for detailed explanations and use of these variables. Given that the P-values for both "X Variable 1" (Lagged Monthly Heating Degree Days) and "X Variable 3" (Weighted Time Trend) exceed a value of 0.05, this regression cannot be deemed to be statistically significant and must therefore be rejected for consideration. Comparatively, a review of the P-value results of the regression equation variables for the Company's 18-year regression, as found in UGI Gas Book II, Attachment SDR-RR-11(a), page 9 of 9, shows the following:

Variable	*P-value*
Intercept	7.99903E-21
X Variable 1	0.00029753
X Variable 2	2.5251E-103
X Variable 3	0.048641189

Here, all P-values in the Company's regression analysis are below a value of 0.05, thus demonstrating the Company's approach as being statistically significant for the determination of Rate R/RT residential heating use per customer.

Q. Has I&E maintained a similar consistent approach to use per customer methodology in prior UGI Gas rate cases?

A. No. I&E's methodology for determining use per customer has varied in UGI Gas's most recent rate cases. In this case, I&E claims to base its position on a 15-year period but then provides workpapers showing that it is relying on a 5-year and 1-month period. In the 2020 UGI Gas base rate case, I&E proposed to use 15 years of data, and I&E proposed using a 10-year regression period during the Company's 2019 base rate case.

III. REVENUE ALLOCATION AND RATE DESIGN

A. REVENUE ALLOCATION

Q. OCA witness Mierzwa contends that the Company's proposed revenue allocation is not reasonable because it should be based instead on the OCA's cost of service study. (OCA St. No. 3, pp. 32-33.) Do you agree?

A. No. As explained in UGI Gas witness Heppenstall's rebuttal testimony (UGI Gas St. No. 10-R), Mr. Mierzwa's criticisms of the Company's cost of service study should not be adopted by the Commission. Therefore, because the Commission should reject the OCA's cost of service study, the Commission should likewise reject the OCA's proposed revenue allocation based on such cost of service. Mr. Mierzwa did not provide a revenue allocation based on the Company's cost of service for direct comparable assessment.

Q. OSBA witness Knecht also disagrees with the Company's proposed revenue allocation. (OSBA St. No. 1, pp. 15-16.) Why?

A Mr. Knecht provides two reasons. First, he "disagree[s] that rate decreases should be assigned to the Rate XD and Rate IS classes" because "[t]hese customers are subject to negotiated rates, which have already been accepted by the customers." (OSBA St. No. 1, p. 15.) Therefore, he "propose[s] to set the rate increases for those customer classes at zero and (implicitly or explicitly) roll the current [Distribution Service Improvement Charge ("DSIC")] revenues into the regular rates." (OSBA St. No. 1, p. 15.) Second, under his alternative cost of service study, he believes that the Company's proposed revenue allocation to the Rate N/NT class is "inequitable" because "it would result in relatively small progress toward cost-based rates compared to the other classes." (OSBA St. No. 1, p. 15.) As such, he recommends modifying "the Company's proposed revenue allocation by (a) setting the rate increase for the R/RT class at 1.5 times the system average increase (1.5 x 12.6% = 18.9%), and (b) set the increases for the N/NT, DS and LFD classes to produce equivalent progress toward cost-based rates." (OSBA St. No. 1, p. 15.)

Q. Do you agree with Mr. Knecht?

A. No, I do not. In his rebuttal testimony, Mr. Brown explains why the Commission should reject Mr. Knecht's recommendation to set rate increases for Rates XD and IS at zero (UGI Gas St. No. 1-R). Thus, the Company's revenue allocation for Rates XD and IS should be adopted as filed by the Company.

In addition, the Company continues to believe that an increase for the Rate R/RT customer class of 2.0 times the system average increase is appropriate, just, and reasonable. The Company has consistently utilized this standard in its rate cases as it does address the ratemaking principle of gradualism. An increase of 2.0 times the system average increase is further supported as appropriate for Rate R/RT in this case in order to move the only class demonstrating lower than system average returns closer to paying a system average rate of return; a demonstration of equity across all rate classes. Thereafter, setting the increases for the Rate N/NT, DS, and LFD classes to produce equivalent progress toward cost-based rates as Mr. Knecht recommends is agreeable to the Company.

B. RATE DESIGN

1. RATE UNIFICATION

Q. Do any of the parties oppose the Company's proposal to unify the rates for Rate N/NT and Rate DS customers?

A. Yes. OSBA witness Knecht opposes the Company's proposal, arguing that unifying Rate DS and Rate N/NT will require a very large rate increase for former UGI Gas North Rate District customers. (OSBA St. No. 1, pp. 19-20.) Therefore, he recommends that the rate increase for those customers be no more than 1.5 times the system average increase. (OSBA St. No. 1, pp. 20-21.)

Q. Do you agree with Mr. Knecht?

A. No. As noted in my direct testimony, the Company has now proposed to unify the rates for these customers since the Company's 2019 base rate case filing. This is the Company's third attempt to unify these rates, and by not doing so now, Rate DS customers in the former South and Central Rate Districts will continue to support an intra-class subsidy for the Rate DS customers in the former North Rate District, and all Rate DS customers will still not be treated equally as a total class. The Company believes such intra-class subsidies are no longer appropriate and should be removed as part of establishing final rates in this proceeding. Specifically, as related to Rate N/NT unification, the differential in distribution commodity rates is now relatively narrow in magnitude at just \$0.36/Mcf under present rates. (*See* UGI Gas Exhibit E, page 3 of 7.) Therefore, the differing impacts of final rates for former North versus former South/Central Rate District customers should not be deemed a material barrier to final unification; if needed to achieve Rate N/NT unification, the Company would advocate a small reduction in the proposed Rate N/NT customer charge.

As related to Rate DS unification, if the Commission does not permit full harmonization as proposed by the Company, the Commission should permit former North

Rate District Rate DS rates to be increased by 2.0 times the system average increase in this proceeding. Mr. Knecht recently testified in Columbia Gas of Pennsylvania, Inc.'s ("Columbia") 2021 rate case (Docket No. R-2021-3024396) that "[t]he increase to the Large General Service is a little below 2.0 times the system average increase (which is also a rule-of-thumb for rate gradualism)." (*See* UGI Gas Exhibit SAE-2R, p. 25 of 40.) He also criticized Columbia's proposed revenue allocation because, among other reasons, "it [would] take many rate proceedings to move rates into line with allocated cost if the 1.5 times system average factor is applied." (*See* UGI Gas Exhibit SAE-2R, p. 24 of 40.) Here, consistent with Mr. Knecht's testimony in Columbia's 2021 rate case, UGI Gas is using the "rule-of-thumb for rate gradualism" of 2.0 times the system average increase and is trying to avoid "many rate proceedings" to unify the Rate DS rates, given that this is the Company's third attempt to unify these rates.

For these reasons, the Commission should also then explicitly authorize the Company to implement final Rate DS unification with a rate change to be effective October 1, 2023, or approximately one year from the date of effective rates in this proceeding, such that UGI Gas has a defined and final pathway to fully unified rates as part of the outcome of this rate case proceeding. In total, this approach will have allowed a full 5-year period (2018 through 2023) for Rate DS harmonization to occur; an approach that is fully consistent with the ratemaking principle of gradualism.

2. RESIDENTIAL CUSTOMER CHARGE

Q. Do any of the parties disagree with the Company's proposal to increase the residential customer charge from $14.60 to $19.95?

A. Yes. OCA, CEO, and CAUSE-PA disagree with the Company's proposed increase for the residential customer charge. (OCA St. No. 3, pp. 4, 36-38; OCA St. No. 4, pp. 4, 11; CEO St. No. 1, pp. 32-35; CAUSE-PA St. No. 1, pp. 4-6, 6-7, 12.)

Q. Could you please summarize OCA's position?

A. OCA witness Mierzwa recommends that the Commission deny the Company's proposal and, instead, increase the residential customer charge no higher than $16.00. (OCA St. No. 3, pp. 4, 36-38.) He claims that the Company's proposal: (1) is out of line with the residential customer charges of other natural gas distribution companies ("NGDCs") in Pennsylvania; (2) violates the principle of gradualism; and (3) is inconsistent with the Commission's goal of fostering energy conservation. (OCA St. No. 3, pp. 36-38.) Mr. Mierzwa also asserts that a higher customer charge "may counter the EE&C Plan's effectiveness, as it limits the amount of potential bill savings through the reduction of variable charges, which may in turn, discourage ratepayers from implementing energy conservation measures." (OCA St. No. 3, pp. 37-38.) Relatedly, OCA witness Colton recommends that the residential customer charge proposed by Mr. Mierzwa be approved. (OCA St. No. 4, pp. 4, 11.)

Q. Do you agree with Mr. Mierzwa?

A. No. First, a strict comparison of the customer charges between utilities, on its own, is not appropriate in determining whether the customer charge that UGI Gas has proposed here is just and reasonable. Such an approach assumes that the customer component of cost of service is the same for all NGDCs in the Commonwealth, and there is no evidence to support this conclusion. Also, the relative level of customer charges can impact the frequency of base rate filings, which are the only way to change customer charges. As an example, National Fuel Gas Distribution Corporation ("National Fuel") has not had a base rate case for more than 20 years, which is certainly reflected in its lower customer charge. Moreover, UGI Gas and Columbia have had recent base rate proceedings, due in large part to their active main replacement programs. Therefore, it is not surprising that these two utilities would have higher customer charges that are reflective of the supporting cost of service analyses.

Here, UGI Gas's proposed customer charge is fully supported by its cost of service study, which shows that an even higher customer charge is appropriate. For Rate R/RT, UGI Gas Exhibit D, Schedule G, pages 1-2, show a fully-allocated customer cost per bill of $33.29 and a direct customer cost per bill of $27.47. The Company's direct costs per bill are greater than the customer charges proposed by the Company in this case. In other words, the Company's proposed customer charges are fully supported by its costs. The direct customer costs for service to residential customers are well in excess of the Company's proposed customer charge of $19.95 per month at $27.47 per month, as shown in UGI Gas Exhibit D, Schedule G, page 2 of 2. I would also note that OSBA witness Knecht performed his own cost of service analysis, which likewise supports the Company's proposed $19.95 customer charge for Rate R/RT. Specifically, he testified that his "CSAS simulation at the UGI Gas proposed rates" shows that "the full customer component of residential class costs is about $33 per customer per month." (OSBA St. No. 1, p. 22.) This means that the Company must then recover the remaining portion of those direct customer costs above $19.95 per month, which are still fixed costs, on a volumetric basis rather than through a fixed customer charge. The mathematical result of this mismatch between cost structure and rate structure is that lower-than-average use residential customers are inherently subsidized by higher-than-average use residential customers. By comparison, Mr. Mierzwa provides no cost of service support for his residential customer charge maximum of $16.00 per month.

A more correct categorization of the Company's proposed customer charge is that it will produce a more appropriate recovery of the cost to serve lower use customers. By not moving the customer charge toward an amount that is reflective of direct customer cost, higher use customers will continue to subsidize lower use customers. As discussed in the rebuttal testimony of Mr. Adamo (UGI Gas St. No. 12-R), low-income customers are, on average, higher use customers. Thus, an increase in customer charge both better aligns cost recovery with cost causation and also serves to reduce the burden on low-income customers. As to the issue of encouraging conservation, even with the Company's as-proposed $19.95 customer charge, the Company's Rate R/RT volumetric charges will be required to increase under the Company's $82.7 million proposed increase. Moreover, the other volumetric charges, such as the purchased gas cost rate, are unaffected. Thus, under the Company's proposal as shown in UGI Gas Exhibit E, page 2 of 7, the incentive for customer conservation would be increased under proposed rates ($4.9996/Mcf) when compared to that incentive at current rates ($4.1104/Mcf), as the customer will continue to save on the volumetric portion of their bill.

In addressing the issue of gradualism, it is important to note that the concept of gradualism should be applied to the <u>overall</u> distribution rate increase impacting the total bill and not individual sub-components of the rate design. For example, if a customer's monthly customer charge increased by $5 but then the other distribution charges were decreased by $5 in total, there would be no net impact on the customer's bill. Therefore, separate consideration of gradualism for changes to the customer charge and the other distribution charges is not appropriate. Instead, gradualism should be used to evaluate the rate increase's total overall bill impact on the distribution charges. Thus, Mr. Mierzwa's focus on the concept of gradualism applying to a subset of bill charges is misplaced.

Q. CAUSE-PA witness Geller also opposes the Company's proposed residential customer charge and recommends that any rate increase be applied to the volumetric charge only. (CAUSE-PA St. No. 1, pp. 32-35.) Why does he disagree with the Company's proposal?

A. Mr. Geller claims that the proposed increase in the residential customer charge will adversely affect low-income customers and the Company's Low-Income Usage Reduction Program ("LIURP"). (CAUSE-PA St. No. 1, pp. 32-35.)

Q. Similar to CAUSE-PA witness Geller, CEO witness Brady opposes any increase to the monthly customer charge. (CEO St. No. 1, pp. 4-6, 6-7, 12.) Why does he disagree with the Company's proposal?

A. Mr. Brady believes that the proposed increase to the residential customer charge will affect a customer's ability to conserve and that changes to funding for LIURP and other universal service programs can help mitigate that effect. (CEO St. No. 1, pp. 4-6.) He also cites a statement by former Commissioner James Cawley in National Fuel's 2006 base rate case as alleged support for his position. (CEO St. No. 1, pp. 6-7.)

Q. Do you agree with CAUSE-PA witness Geller and CEO witness Brady?

A. No. As explained in the rebuttal testimony of UGI Gas witness Heppenstall (UGI Gas St. No. 10-R), UGI Gas witness Taylor (UGI Gas St. No. 11-R), and UGI Gas witness Adamo (UGI Gas St. No. 12-R), their criticisms of the Company's proposed increase for the residential customer charge lack merit. Therefore, I maintain that the Company's proposed increase for the residential customer charge should be approved.

Q. Do you agree with OCA witness Mierzwa that his recommended customer charge of $16 should be scaled back if the Company is not awarded the fully requested increase in this case?

A. No. As explained above, the Company's proposed customer charge of $19.95 is fully supported by the both the Company's cost of service study as well as the one provided by OSBA. These fixed costs will not change in any material amount as a result of the ultimate revenue increase approved in this case. Thus, even if a lower amount were approved and Mr. Mierzwa's $16 customer charge were adopted, the customer charge should not be further scaled back.

3. BALANCING CHARGES

Q. Does OCA witness Mierzwa recommend any changes to the Company's balancing service charges?

A. Yes. Mr. Mierzwa disagrees with the Company's proposal to decrease the current charge for Rate NNS from $0.4880 per Mcf/day of elected No-Notice Allowance ("NNA") to $0.1860 per Mcf/day of elected NNA. (OCA St. No. 3, pp. 39-40.) He also disputes the

Company's proposed balancing charges for Rate MBS, which are based on an anticipated average transportation customer monthly imbalance of 2.5737%. (OCA St. No. 3, pp. 40-42.)

Q. Please summarize Mr. Mierzwa's position regarding the Company's proposed change to Rate NNS's balancing charge.

A. Mr. Mierzwa contends that Purchased Gas Cost ("PGC") and "non-Choice transportation customers should receive a contribution toward the fixed costs associated with the storage assets utilized to provide service under Rate NNS" because they "are currently responsible for all of the demand charges associated with the interstate pipeline storage resources utilized to provide Rate NNS." (OCA St. No. 3, p. 40.) For these reasons, Mr. Mierzwa recommends that the storage trip cost be adjusted to include the demand charges associated with providing service under Rate NNS on a 100% load factor basis. (OCA St. No. 3, p. 40.) Doing so would increase the storage trip cost to $1.425 per Mcf and increase the charge for Rate NNS service to $1.9960 per Mcf/day of elected NNA (*i.e.*, an increase of $1.81 per Mcf/day of elected NNA from the Company's proposed charge of $0.1860 per Mcf/day of elected NNA, and an increase of $1.508 per Mcf/day of elected NNA from the Company's current charge of $0.4880 per Mcf/day of elected NNA). (OCA St. No. 3, p. 40.)

Q. Do you agree with Mr. Mierzwa's position on the Rate NNS balancing charge?

A. No, I do not. Non-choice transportation customers pay for their use of interstate pipeline storage resources through both Rates NNS *and* Rate MBS. In particular, Rate NNS accommodates daily imbalance variances, while Rate MBS accommodates carrying the net imbalance from one month into the next without the need to cash-in/out, or bring the balance to zero, at month end. Of important note, the same storage assets are used to provide both these services in aggregate. Thus, one must look at the full contributions non-choice transportation customers make to the cost of interstate pipeline storage resources by considering revenues paid under both Rate NNS and Rate MBS and determine if any underpayment for these services is being made by non-choice transportation customers. In his review of Rate NNS charges, Mr. Mierzwa has not performed any assessment of how much the same non-Choice transportation customers will already pay towards the cost of the demand and capacity costs of storage resources as being Rate MBS subscribers under the Company's proposal. Thus, he has not considered if Rate MBS payments already pay for the demand and capacity costs at a sufficient level, which would then require no additional contribution to these fixed costs for the provision of Rate NNS service. The Company has only assigned true incremental variable storage costs for injection and withdraw costs to Rate NNS under proposed rates and believes Mr. Mierzwa should do the same.

Q. Have you performed such an assessment of storage utilization and cost allocation for Rate NNS and Rate MBS subscribers, which demonstrates no fixed storage and demand costs should be allocated to Rate NNS?

A. Yes. Because Rate MBS subscribing customers are allocated storage demand and capacity costs for storage under the Company's proposed Rate MBS, it is appropriate to quantify how much demand and capacity these customers are paying for currently. The average monthly Rate MBS revenue is $112,084 for the 12-month period ending September 2021. (*See* UGI Gas Exhibit SAE-3R, a copy of Attachment OCA-I-8(d), which the Company provided in discovery and contains actual MBS revenues by month for the period.) Also, as noted on UGI Gas Exhibit SAE-9, line 1, the weighted average 100% load factor unit cost for storage demand and capacity is $1.292/Mcf. Thus, by division, it can then be determined that non-Choice transportation customers are paying for 86,752 Mcf ($112,084/$1.292) of storage demand and capacity by virtue of their Rate MBS payments. Again, this capacity is the same capacity utilized to provide both Rate MBS service as well as Rate NNS service. Therefore, if the daily utilization of Rate NNS's balancing service does not exceed 86,752 Mcf, then any additional allocation of storage demand and capacity costs to Rate NNS, as Mr. Mierzwa is proposing, is inappropriate and unsupported based on cost causation principles.

Here, no additional cost assignment of storage demand and capacity costs is appropriate because Rate NNS service only requires the use of 33,772 Mcf of the 86,752 Mcf. Specifically, Rate NNS customers' average daily metered use is 216,053 Mcf. (*See* UGI Gas Exhibit SAE-4R, a copy of Attachment OCA-I-9, page 3 of 3, which the Company provided in discovery.) Rate NNS customers also have an actual usage reduction on weekday versus weekend days of 15% per UGI Gas Exhibit SAE-8, Weekend Load Reduction Factor ("WELF") value. Solving for the average weekday and weekend usage levels using the 15% reduction factor, it can be determined that average weekday use is 225,702 Mcf per day and average weekend use is 191,930 Mcf per day. In proof, 5 days multiplied by 225,702 Mcf per day plus 2 days multiplied by 191,930 Mcf per day and then all divided by 7 days equals 216,053 Mcf per day on average. As such, Rate NNS customers require 33,772 Mcf (*i.e.*, average weekend usage of 225,702 Mcf minus average weekday usage of 191,930 Mcf) of storage demand and capacity in order to accommodate weekend versus weekday balancing variances. As these same customers are already paying for 86,752 Mcf of capacity under Rate MBS, and because providing these same customers with Rate NNS service only requires the use of 33,772 Mcf of that total 86,752 Mcf, no additional cost assignment of storage demand and capacity costs is appropriate. Rate NNS need only pick up the incremental storage commodity injection/withdrawal round trip costs – as the Company has proposed for Rate NNS. (*See* UGI Gas Exhibit SAE-8.) Thus, Mr. Mierzwa's proposal to assign additional storage demand and capacity costs to Rate NNS is not supported, and his recommendation should be rejected by the Commission.

Q. Please summarize Mr. Mierzwa's position regarding the Company's proposed Rate MBS balancing charges.

A. Mr. Mierzwa alleges that the Company's proposed Rate MBS balancing charges "are not reasonable" because instead of being "based on an anticipated average transportation customer monthly imbalance of 2.5737 percent," they should be "based on a transportation monthly imbalance of to [sic] 5 percent to reflect the additional 5 percent monthly imbalance tolerance provided under Rate MBS." (OCA St. No. 3, pp. 41-42.) He then presents the proposed Rate MBS charges in OCA Schedule JDM-3.

Q. Do you agree with Mr. Mierzwa's position on the Rate MBS balancing charges?

A. No. Mr. Mierzwa fails to recognize that the 2.5737 percent imbalance on which the Rate MBS calculation update is based is not an "anticipated" average transportation customer monthly imbalance. Rather, as noted in footnote 2 to that value on UGI Gas Exhibit SAE-9, the 2.5737 percent imbalance is based on the "[a]verage monthly imbalance percentage include[ing] all non-Choice transportation customers electing MBS" and the "[a]verage monthly imbalance percentage based on historical data for the period Nov 2020 through Oct 2021." As a result, the Company's proposed updates to Rate MBS are based on actual use, whereas Mr. Mierzwa's proposes to assign a full 5 percent allocation to Rate MBS subscribers based on the maximum amount a Rate MBS customer could utilize. Such an approach is not appropriate when the best available data of "actual" utilization is readily available. Moreover, by crediting all Rate MBS revenues to the PGC, Mr. Mierzwa's proposal would give PGC customers a windfall of additional revenue and create an unjust cross-subsidy.

Q. Has the Company used actual data for Rate MBS calculations historically?

A. Yes. The Company has historically utilized actual data from the 12-month period ending prior to the rate case filing when developing a cost allocation for Rate MBS. The benefits of having that actual data available to perform precise Rate MBS calculation updates based on actual use should be recognized by Mr. Mierzwa in lieu of advocating for a 5% maximum based on a hypothetical use. Thus, Mr. Mierzwa's proposed updates to Rate MBS should be rejected by the Commission in favor of the Company's more accurate cost allocation method.

4. PROPORTIONATE SCALE-BACK OF RATE INCREASE

Q. If the Commission awards less than the Company's proposed base rate increase, both OCA witness Mierzwa and OSBA witness Knecht suggest a proportionate scale-back

of the rate increase. (OCA St. No. 3, p. 35; OSBA St. No. 1, pp. 16-17, 20-21, 23.) How do you respond?

A. If the Commission grants less than the requested increase (termed a "scale back"), then the increases by classes as proposed by the Company should be adjusted proportionate across all classes. Once allocations are determined for each class, the scale-back should then be applied to adjust only the distribution charge portion of the Company's proposed rates as, under both the Company's and OSBA's cost allocation methodologies, the Company's as-proposed customer charges are fully supported.

IV. TARIFF CHARGES

Q. CAUSE-PA witness Geller recommends that UGI Gas no longer assess late fees and reconnection fees to low-income customers because, according to him, they unfairly penalize low-income customers that are unable to afford their bills. (CAUSE-PA St. No. 1, pp. 6, 37.) How would his proposal affect the test year revenue?

A. The reasons why Mr. Geller's recommendation is not appropriate to adopt are discussed in the rebuttal testimony of UGI Gas witness Adamo (UGI Gas St. No. 12-R), and Mr. Adamo specifically explains how the Company does not assess late fees to confirmed low-income customers who receive LIHEAP or are on CAP. He also explains that reconnection fees address the costs incurred when UGI Gas dispatches personnel to restore service.

However, should the Commission adopt Mr. Geller's recommendation regarding reconnection fees, FPFTY present rate revenues would need to be adjusted downward by the related revenues. Pursuant to the FY21 reconnection data provided in the table below, the resulting adjustment would lower FPFTY margin revenues by $0.275 million for

Reconnection Fees. This reduction would commensurately add to the Company's requested increase by a like amount.

Number of Reconnections By Month in 2021	**CLI**	**Total Reconnection Fees**
January	0	$0
February	1	$73
March	5	$365
April	54	$3,942
May	733	$53,509
June	951	$69,423
July	485	$35,405
August	360	$26,280
September	430	$31,390
October	289	$21,097
November	381	$27,813
December	82	$5,986
Total	***3,771***	***$275,283***

V. <u>CONCLUSION</u>

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit SAE-1R

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to I&E (RS-12-D thru RS-16-D)
Delivered on March 15, 2022

I&E-RS-14-D

Request:

Reference UGI SDR-RR-11(a) page 8 as of September 2023 showing 87.9625 Mcf labeled “FY 23”.

A. Does the 87.9625 Mcf represent the normal annualized usage of a customer on September 30, 2023, or some other point in time?

B. Does the 87.9625 Mcf represent the average normal annualized usage for the twelve months ending March 31, 2023, or some other period of time?

Response:

A. The normal annualized usage of a customer as of September 30, 2023 is 87.8138 Mcf, and is noted as “Fully Projected Future Test Year Annualized FY 23” in the last column shown on page 8 of UGI SDR-RR-11(a). The value of 87.9625 Mcf represents the normalized annualized usage as of March 31, 2023. By way of further response, for the end of any specific month listed in the first column of the referenced page 8, the normalized annualized usage for such month can be determined by summing the 6 months of “1 Month UPC” data up to such specific month and the 6 months following such specific month; this represents the use of a mid-period convention in determining UPC.

This projection of data is needed in order to properly annualize customer usage for conditions existing at the end of the FPFTY for all customers in the residential class. Specifically, in order to establish use per customer as of the end of the FPFTY, or as of September 30, 2023, the company utilized a mid-period convention in order to capture the full annualized impacts related to customer conservation activities through that date. As September 30, 2023, is the middle of the annual period ending March 31, 2024, the projected annualized value for use per customer for that 12-month period would represent the annualized rate of use for those customers existing as of September 30, 2023.

A single customer example will help demonstrate this mid-point convention use in calculating usage per customer. For example, assume the 12-month history of an individual customer’s actual gas usage for a twelve month period ending on September 30, 2023, totals 85 Mcf and is reflective of the customer’s usage of their then-existing 80% efficient heating equipment during the 2022-2023 heating season (the season

UGI Utilities, Inc. - Gas Division
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I&E-RS-14-D (Continued)

ending March of 2023). If that customer installs a new, 95% efficient heating system in July of 2023, the customer's annual projected usage will drop to 71.5 Mcf per year as of the day the new system is installed in July. (85 Mcf use x 0.80 old furnace efficiency = 68 Mcf heat requirement; 68 Mcf heat requirement/0.95 new furnace efficiency = 71.5 Mcf use) The Company's method captures this new, lower usage resulting from an installation prior to the end of the FPFTY and is appropriate to include in an annualization.

B. Yes. Please see the response to A, above.

Prepared by or under the supervision of: Sherry A. Epler

UGI Gas Exhibit SAE-2R

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to I&E (RS-12-D thru RS-16-D)
Delivered on March 15, 2022

I&E-RS-16-D

Request:

Reference UGI SDR-RR-11(a) pages 5-8 where the Company utilized 19 years (2003-2021) of heating degree and usage data.

A. Explain if utilizing 19 years of actual data produces more statistically accurate projection than using a shorter time-period.

B. If yes, provide all statistical or mathematical analysis that shows that utilizing 19 years of actual data produces more statistically accurate projection than using a shorter time- period.

C. If it does not produce more statistically accurate results, explain why the Company selected 19 years of data.

D. Does the Company believe that utilizing a shorter and more recent time period such as five or ten years also produces a statistically accurate projection? If not, explain why not.

Response:

A. The Company evaluated statistical significance of its approach by review of the regression result p-values. In short, the resulting p-values, which are less than 0.05 as shown on UGI Gas SDR-RR-11(a) page 9, demonstrate statistical significance. A general understanding of p-value significance can be found on the statistical website article referenced here:

https://blog.minitab.com/en/understanding-statistics/what-can-you-say-when-your-p-value-is-greater-than-005 . Based on this reference article, analyses fall into "statistically significant" or "not statistically significant", but such analyses are not appropriately utilized to claim one analysis "more statistically accurate" than another. Additionally, the Company has not evaluated all potential time period options for statistical significance (i.e., 17 years, 16 years, 15 years, 14 years, etc.) but rather has relied upon an approach of using a data set which contains all historically available data. Historically this approach has consistently resulted in statistical significant output.

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
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Delivered on March 15, 2022

I&E-RS-16-D (Continued)

By way of further response, the Company included 18 years (FY 04-FY 21) in UGI SDR-RR-11(a). In the UGI Gas rate case two years ago, the Company used 16 years of data in its analysis. At that time, that 16-year period represented the time period for which the Company had common data across all three of the former UGI gas utility rate districts: UGI South Rate District, UGI North Rate District, and UGI Central Rate District. October 2003 was the beginning of that dataset and thus the Company used all available historical data. (The use of non-common data, or differing periods by rate district, would result in different weighting that would skew results and thus could not be used.) The Company has now extended that 16-year period for the additional two years of data which has been collected since that time and has appended those additional years to the data set used two years ago in forming the 18-year analysis period for this case.

B. Please see the response to A above.

C. Please see the response to A above.

D. Please see the response to A above.

Prepared by or under the supervision of: Sherry A. Epler

UGI Gas Exhibit SAE-3R

COMMONWEALTH OF PENNSYLVANIA

June 16, 2021

The Honorable Mark A. Hoyer
Deputy Chief Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. 2021 Base Rate Filing / Docket No. R-2021-3024296

Dear Judge Hoyer:

Enclosed please find the Direct Testimony of Robert D. Knecht, labeled OSBA Statement No. 1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

OSBA Statement No. 1

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3024296**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Direct Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Context
Negotiated "Flex" Rates
Cost Allocation
Revenue Allocation
Rate Design

Date Served: June 16, 2021

Date Submitted for the Record: ______________________

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. Witness Identification and Summary of Conclusions

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. I specialize in the economic analysis of basic industries. As a large part of my consulting practice, I have prepared analyses and expert testimony in the field of regulatory economics on a variety of topics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and a M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance. I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). My résumé and a listing of the expert testimony that I have filed in utility regulatory proceedings during the past five years are attached in Exhibit IEc-1.

I submitted testimony in the base rates proceedings involving Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") in 2008 (Docket No. R-2008-2011621), 2010 (Docket No. R-2009-2149262), 2011 (Docket No. R-2010-2215623), 2012/2013 (Docket No. R-2012-2321748), 2014 (Docket No. R-2014-2406274), 2015 (Docket No. R-2015-2488056), 2016 (Docket No. R-2016-2529660), 2018 (Docket No. R-2018-2647577) and 2020 (Docket No. R-2020-3024296). I also submitted testimony in a variety of Section 1307(f) and other proceedings involving the Company over the past decade.

Q. Please describe your assignment in this matter.

A. The OSBA requested that I review the Company's filing in this proceeding to evaluate whether the rates proposed for small business customers are consistent with sound economics and regulatory principles. My analysis focuses primarily on issues of cost allocation, revenue allocation and rate design. If I have not addressed a particular issue, it cannot be inferred that I agree with Columbia's proposal for that topic.

Q. Please provide some background regarding the Company's filing, in the context of recent base rates proceedings.

A. Columbia submitted base rates filings in 2008, 2010, 2011, 2012, 2014, 2015, 2016, 2018, 2020 and now 2021. Prior to 2008, Columbia had not filed a base rates case since 1995. This steady flow of rate cases has generally been prompted by the Company's mains and services replacement program, undertaken over the past decade. A summary of the base rates filing amounts and settlement rate increases is shown in Table IEc-1 below.

Table IEc-1
Recent Columbia Base Rate Increase Cases

Docket No.	Test Year Ending	Proposed Increase ($mm)	Award Amount ($mm)	Award Percent
R-2008-2011621	Sep-2008	$58.9	$41.5	71%
R-2009-2149262	Sep-2010	$32.3	$12.0	37%
R-2010-2215623	Sep-2011	$37.8	$17.0	45%
R-2012-2321748	Jun-2014	$77.3	$55.3	72%
R-2014-2406274	Dec-2015	$54.1	$32.5	60%
R-2015-2468056	Dec-2016	$46.2	$28.0	61%
R-2016-2529660	Dec-2017	$55.3	$35.0	63%
R-2018-2647577	Dec-2019	$46.8	$26.0	56%
R-2020-3017206	Dec-2021	$100.4	$63.5	63%
Total		**$509.1**	**$310.8**	**61%**
R-2021-3024296	Dec-2021	$98.3	--	--

Note that Columbia's relatively large increase in the R-2012-2321748 proceeding was due in part to the switch to using a fully forecasted future test year approach, thereby incorporating nearly three full years of (mostly forecast) capital expenditures in the mains replacement program since the prior base rates case. Recognizing that change, it is apparent that the Company's cost requirements have accelerated, with relatively large proposed increases in both 2020 and the current case.

With its proposed increase, Columbia appears to now have the dubious distinction of having the highest residential and small commercial base rates among large natural gas distribution companies ("NGDCs") in the Commonwealth).[1]

Q. Is there an end in sight for these regular large base rate increases?

A. While I have not tracked down the Company's intermediate term financial forecast at this writing, it does not appear so.[2]

The Company has generally cited to aggressive replacement of obsolescent and unsafe equipment as the primary driver for the ten base rates cases of the past thirteen years, which has resulted in enormous rate increases. Over that period, the Company reports that it has installed 1,583 miles of pipe, of which 1,151 represent priority pipe replacements. As percentages of its 7,656 miles of system pipe, these represent 21 percent and 15 percent respectively.[3] Total expenditures over that period for mains was about $1.4 billion.

Despite this massive capital spend, the Company appears to report that nearly 40 percent of its gas distribution mains either require priority replacement or are nearing the end of their useful lives.[4] Measured as a percent of system mains, this includes 15 percent of mains that are cast iron or bare steel that are currently deemed to be priority replacement and are recognized in the Company's current Long-Term Infrastructure Improvement Plan ("LTIIP"). In addition, in this proceeding, the Company indicates that an additional 8 percent of its total mains are "pre-1982 plastic" and 16 percent are "pre-1971 coated" pipe, both of which are deemed to be nearing the end of their useful life and will be incorporated into the Company's next LTIIP. Moreover, even within the current LTIIP, Columbia forecasts an accelerating rate of service line replacements.[5]

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[1] See RDK WP1, "Rate Comp" worksheet.

[2] I understand that the response to OSBA-I-1 was inadvertently not timely posted to the Company's "Box" site for responses.

[3] Columbia Statement No. 1 at 14, OSBA-I-2, OSBA-I-3, RDK WP2.

[4] OSBA-I-2.

[5] *Id.*

The cost for this enormous physical replacement requirement is compounded by the rapidly increasing cost per mile to replace mains, reflecting a variety of factors not least of which is the burgeoning demand for qualified contractors from all Pennsylvania NGDCs. Between 2007 and 2020, the cost to replace a mile of pipe has increased at an average annual rate of about 9.5 percent, far in excess of consumer price inflation.[6] Over that period, the cost per mile has essentially tripled.

Q. Will the Company be able to fully recover its allowed return of and on this massive capital spend over the longer term?

A. I do not know. We all recognize that there are growing societal and political concerns regarding the burning of fossil fuels, and there is concomitant increasing pressure for electrification, not only in transportation but in home heating. For the past fifteen years, the Company's cost competitiveness has been rescued by the hydraulic fracturing boom and the resulting decline in natural gas commodity prices. It is most unlikely that will happen again, given the low current market commodity prices and the financial pressures on drillers. If Columbia's distribution rates continue to grow at the historical rate, heating alternatives (heat pumps, mini-splits) will become more economically attractive to customers. And, of course, there is the potential for increased regulation of CO_2 emissions for both gas consumers and gas producers, both of which could further increase the cost of gas.

In this light, it is somewhat surprising that the Company does not make longer term financial forecasts to evaluate these issues. The Company reports that it has no detailed financial forecast longer than five years.[7]

Q. What are the implications of these trends for the current rate proceeding?

A. Given the lack of a long-term financial forecast, I do not believe that the Company has demonstrated that its overall capital spending plan is prudent. While I cannot comment on the legal issues, I believe the Commission should advise Columbia that future capital expenditures have not been shown to be part of a demonstrably prudent long term investment

[6] RDK WP2 "Main" worksheet.

[7] OSBA-I-1.

plan, and that they can be subjected to *ex post* prudence reviews should they become stranded. At a minimum, I believe the Commission should require Columbia to demonstrate that it has a long-term viable business as part of its next LTIIP filing.

Q. Do you have any preliminary general comments regarding cost allocation and rate design in this proceeding?

A. I do. In the Company's last base rates proceeding at Docket No. R-2020-3017206, the Commission approved the use of a "peak-and-average" ("P&A") method for mains cost allocation, and the Commission accepted the Company's position with respect to negotiated rate revenues from its "flex" rate customers.[8] For the current proceeding, these decisions have three significant impacts.

First, the costs allocated to the regular rate larger industrial customers in the Rate LDS class are roughly double the revenues currently recovered from that class, a shortfall of some $20 million. Moving rates reasonably into line with allocated cost for this class cannot be achieved in a single proceeding, and thus much of this shortfall must be borne by other classes. Moreover, this class can reasonably expect significant rate increases on top of the system average base rate increases discussed above.

Second, the costs allocated to negotiated "flex" rate customers are nearly 10 times higher than the revenues generated by these customers, under the negotiated rate agreements that were generally approved by the Commission in the last base rates case. This results in a shortfall of $30 million, none of which can be recovered from the flex rate customers due to the negotiated contract rates. This shortfall must therefore be reassigned to the other rate classes, including the regular rate LDS customers.

Third, because no mains costs are classified as customer-related, the customer portion of allocated costs is materially lower than that presented in previous cost evaluations. This change reduces the potential for cost-based customer charge increases, particularly for non-residential rate classes.

[8] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2020-3017206, Order Entered February 19, 2021, pages 211-218 and 240-241.

2. Review of Columbia's Non-Residential Rate Classes

Q. Before getting into the details of your analysis, please summarize the rate classes under which businesses take service from Columbia.

A. Columbia's tariff has a number of schedules under which non-residential customers take service. These tariff schedules are generally distinguished by size of customer (as measured by annual throughput) and type of service. Service types include the following:

- Sales service, in which customers procure both gas supplies and distribution service from Columbia;
- Retail transportation "Choice" service, in which smaller customers can purchase gas supply from NGSs and purchase both bundled load balancing services and distribution services from Columbia;
- Transportation service, in which larger non-residential customers purchase gas supplies from NGSs, purchase load balancing services as needed from Columbia and/or their NGSs, and purchase distribution service from Columbia.

For cost allocation purposes, Columbia aggregates these disparate rate classes into rate class groups.

In total, the non-residential rate classes represent about 58 percent of Columbia's total throughput, or about 47 million of Columbia's total 82 million Dth in the test year. Customer size varies widely, ranging from small businesses that consume less than 10 Dth per year to very large industrial customers with individual loads exceeding 2.5 million Dth per year.

The following are the non-residential rate class groups specified by Columbia for its cost allocation analysis. Because the Company's abbreviations for the rate class groups are somewhat contradictory, I include descriptive names for these groups.

SGSS/SCD/SGDS ("Small General" or "SGS"): This group consists of three tariff schedules: Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD"), and Small General Distribution Service ("SGDS"). To reflect the range of costs associated with serving these diverse classes, Columbia has adopted differentiated customer and commodity charges for customers in this group of classes, split between customers with annual consumption above and below 644 Dth. Maximum annual throughput for this class is 6,440 Dth/year. Consistent with recent past practice, the Company separates these two groups for both cost allocation and rate design purposes. For simplicity, I refer to the customers with annual consumption below 644 Dth as "SGS1," and the larger customers as "SGS2."

Within these two rate class groups, SGSS is sales service, SCD is retail "Choice" transportation service and SGDS is regular transportation service.

In the SGS1 group, about 69 percent of the load is to sales customers, implying a shopping rate of 31 percent, which is materially higher than the residential shopping rate of 21 percent. The average SGS1 customer size is about 185 Dth per year, which is a little more than double the size of the average residential customer. Of the shopping customers in this group, about two-thirds of the load is in the Choice program. Overall, this class represents about 12 percent of the Company's non-residential throughput.

In the SGS2 group, about 43 percent of the load relate to sales customers, with the majority of SGS2 shopping customers using traditional transportation service. The average SGS2 customer size is 1,584 Dth/year, which is about 9 times the size of the average SGS1 customer. Overall, this class represents 19 percent of the Company's non-residential throughput.

SDS/LGSS ("Medium General"): This rate class group includes both sales and transportation service customers, taking service under Rate Schedules LGSS (sales service) and Small Distribution Service ("SDS") (transportation service). Columbia's "Small" designation for the transportation customers in this tariff category is misleading, since the *minimum* throughput is 6,440 Dth per year, matching the *maximum* size requirement for the Small General customers. The maximum annual throughput for this class is 54,000 Dth per year, with an average annual customer throughput of about 15,600 Dth. This rate class group (excluding the flex rate customers) represents about 16 percent of non-residential throughput.

LDS/LGSS ("Large General"): This class includes the larger sales customers in the LGSS class along with the transportation service customers taking service under Rate Schedule Large Distribution Service ("LDS"). Minimum throughput is 54,000 Dth per year, matching the Medium General Service upper limit. A significant share of the volume for this rate class is included in the "Flex" rate class category for cost allocation, revenue allocation and rate design purposes.

MDS ("Mainline"): Customers in this rate class group take service under Rate Schedule Main Line Distribution Service ("MDS").[9] To be eligible for this service, customers must have annual throughput over 27,400 Dth *and* be directly connected to an interstate pipeline (Class I), *or* have a minimum annual demand of 214,600 Dth *and* be located within two miles of an interstate pipeline interconnection (Class II). Because these customers require very little in the way of distribution facilities, and because Columbia reports that they are credible "bypass" threats, Columbia uses different cost allocation and rate design methods for this rate class group.

Consistent with recent practice, the Company does not treat large general sales service ("LGSS") customers as a separate rate class for cost allocation purposes, and it includes those customers with transportation customers of comparable size. As I testified in the last several proceedings, I agree with this approach. Sales customers taking service under Rate LGSS are free to switch to the comparable transportation service schedule, and, generally, vice versa. Thus, it is reasonable that the distribution rates for all customers of a similar size be the same, so as to avoid distorting the decision to shop. Since the distribution rates are the same, there is no need to separately allocate costs. Moreover, the total load associated with Rate LGSS is relatively small.

Finally, I note that the tariffs for the Company's larger rate classes allow for discounted, negotiated "flex" rates, for customers who have the potential to economically use an alternative fuel or bypass the distribution system to interstate pipelines or local supply. Rates for these customers are therefore set based on market conditions rather than utility cost to

[9] Columbia's tariff includes a Main Line Sales Service schedule, but no customers currently take service under that schedule.

serve. To allow the Company to set regular tariff rates based on allocated cost, the customers who currently have flexed rates are segregated into a separate class for cost allocation purposes.

3. <u>Flex Rate Customers</u>

Q. Please summarize the economic and regulatory issues surrounding Columbia's "flex rate" customers.

A. In general, regular specific tariff rates are set based on allocated cost of service and other rate design criteria, and these tariff charges apply to all customers within the rate class. However, under certain conditions, it can be beneficial to all parties to allow the utility to negotiate rate discounts from the regular tariff rates to retain customers who have lower-cost competitive options. These options include alternative fuel, pipeline bypass, and in the bizarre case of western Pennsylvania, "gas-on-gas competition" from other natural gas distribution companies ("NGDCs").[10] The specific criteria where negotiated discounts are in the interests of all ratepayers are:

- Negotiated rates exceed the incremental cost of providing service to the customer. Thus, for example, if Columbia needs to upgrade its distribution system to continue to provide service to a flex rate customer, the tariff rates must be sufficient to justify that expenditure.

- In the case of alternative fuel competition, negotiated tariff rates plus the cost of gas should be set at the full delivered cost of the alternative fuel plus the customer's costs of conversion.

- In the case of pipeline bypass, negotiated tariff rates are justified only if there is a credible engineering plan for how the customer could physically bypass the NGDC. If that criterion is met, the negotiated tariff rate plus the cost of gas should be set at the customer's full cost for bypassing the NGDC and taking service directly from

[10] NGDCs do not "compete" for customers in overlapping service territories on the basis of cost or service. They have historically "competed" on the basis of which NGDC can offer the largest rate discount to those customers who have options and pass the cost for those discounts on to captive customers who do not have options.

the pipeline. This cost necessarily includes obtaining the necessary permits to allow for such bypass.

- In the case of NGDC "competition," the Commission has determined that where customers are served in overlapping NGDC service territories, the minimum flex rate that can be charged is the lowest regular tariff rate of the NGDCs serving the customer's location.[11]

Q. Please summarize the positions of the parties and results of the last base rates proceeding regarding flex rates.

A. Columbia Gas argued that its then current revenues for flex rate customers reasonably represented the maximum revenues that the Company could earn from those customers given competitive conditions. The Company therefore argued that those rates were reasonable, and that no portion of the rate increase could be assigned to those customers.

I argued that the Company failed to demonstrate that some of the claimed flex rates were justified, and that the revenue assigned to flex rate customers should include an additional $4.4 million in present rates and $3.3 million as a contribution to the proposed increase.[12]

No other witness challenged the magnitude of the Company's flex rate discounts.[13] Mr. Ethan H. Cline, representing the Commission's Bureau of Investigation and Enforcement ("I&E"), recommended that the Company be required in the future to update a competitive alternative analysis for any customer that had not had its alternative fuel source verified for a period of ten years.

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[11] *Opinion and Order,* Pennsylvania Public Utility Commission, Docket Nos. P-2011-2277868 and I-2012-2320323, Order Entered May 4, 2017, page 52. To my knowledge, there has not been a firm resolution as to how the lowest applicable tariff rate should be defined. See *Opinion and Order,* Pennsylvania Public Utility Commission, Docket Nos. P-2011-2277868 and I-2012-2320323, Order Entered June 13, 2019.

[12] OSBA Statement No. 1-S at 5, Docket No. R-2020-3018835.

[13] CAUSE-PA appears to have argued that flex rate customers should be required to contribute to the recovery of universal service costs.

In the Recommended Decision, Administrative Law Judge ("ALJ") Katrina L. Dunderdale implicitly rejected my recommendation without analysis or comment. ALJ Dunderdale recommended that the I&E proposal for decennial competitive alternative analyses be approved.

OSBA took no exception to ALJ Dunderdale's recommendation in this respect, and the Commission accepted the ALJ's recommendations.

Q. Are there any material differences in the current case?

A. No. In the last case, Columbia had 29 flex rate customers with some 14.1 million Dth in annual throughput. Those values have declined modestly to 23 customers and 11.7 million Dth, which at least indicates that the Company is not encouraging its larger customers to negotiate rate discounts.

Q. Did the Company file the competitive analysis recommended by I&E and approved by the Commission?

A. The Company indicates that it has already conducted a competitive review for every flex rate customer within the past ten years, and thus no competitive review is required.[14]

Q. Have you conducted a detailed review as to whether the Company has set its flex rates consistent with the principles that you outlined above?

A. No. After carefully reviewing the positions of the parties and the decisions of the ALJ and the Commission in the last proceeding (just four months ago), I determined that there was little purpose to raising this issue again in this proceeding.

Q. What are the implications of the flex rates for the Company's revenue requirement in this proceeding?

A. Based on the cost allocation method approved by the Commission in the last case, the costs allocated to the 23 flex rate customers come to $32.9 million, which is nearly ten times the current negotiated rate revenues of $3.4 million. The $29.5 million shortfall must therefore be recovered from the other rate classes.

[14] OSBA-I-8.

4. <u>Cost Allocation</u>

Q. What is the purpose of a utility's allocated cost of service study ("ACOSS")?

A. The primary criterion for setting regulated utility rates is the cost incurred by the utility for providing the service.[15] To assign costs to specific customers, utilities aggregate customers into rate classes, within which the customers have similar load sizes, seasonal consumption, peak demand patterns, and other characteristics. An ACOSS is an analytical tool with which the utility's total cost (or "revenue requirement") is allocated among each of the rate classes. These allocated costs are then used as a key input in determining the total revenues that the utility plans to recover from each rate class through tariff rates.

In using the results from an ACOSS to develop class revenue requirements, utilities and regulatory authorities usually have a longer-term goal of moving the revenue recovered from each class as close as possible to the costs allocated to that class. That is, in each proceeding, regulators try to move class revenues more into line with cost-based rates. Thus, rate classes whose revenues substantially exceed allocated costs are assigned either relatively low rate increases or rate decreases. Rate classes whose revenues are well below allocated costs are assigned larger rate increases than those classes whose revenues are only slightly below allocated costs.

In addition to class revenue requirement issues, an ACOSS can provide useful cost information regarding the specific nature of utility tariff charges. In particular, an ACOSS provides a cost basis for the relative magnitude of the various individual tariff charges, including the customer charge, demand charges and commodity charges.

Q. How does an ACOSS assign costs to the various rate classes?

A. The underlying principle of an ACOSS is that costs are assigned to the rate classes that *cause* the utility to incur those costs. This principle of cost causation is both equitable and economically efficient. It is equitable because costs are borne by those customers who cause them. It is economically efficient because the price signal for consumption from a particular

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[15] The Commonwealth Court affirmed this basic principle, referring to cost of service as the "polestar" criterion. <u>Lloyd v. Pennsylvania Public Utility Commission</u>, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

rate class is reasonably consistent with the cost incurred by the utility to provide the service. In that way, the consumer receives the correct price signal for determining whether he should purchase more or less of the utility service. In effect, the consumer balances the value that he receives from the purchase of that service against the utility's cost of providing the service.

Q. What is the Company's approach to cost allocation in this proceeding?

A. With its filing, the Company presented three detailed cost allocation studies, in Exhibit 111 Schedules 1, 2 and 3. The Company's cost allocation analysis is supported by Mr. Chad Notestone, Columbia Statement No. 11.

Q. Why does the Company present three different cost allocation studies?

A. Some old habits die hard.

The Company has consistently submitted two alternative ACOSS models in its base rates filings stretching back to at least 2008, with a third version that is an average of the two. The models differ only in how mains plant costs are classified and allocated.

The "CD" model classifies and allocates mains costs using a "minimum system" method, in which costs are segregated into a "customer component" and a "demand component." The customer component of costs is derived based on the cost of installing the minimum size pipe throughout the current distribution system, and those costs are allocated based on number of customers. The minimum system construct is designed to reflect the economies of scale of serving and interconnecting larger customers. The remaining costs are deemed to be demand-related. These costs are allocated based on a measure of class peak demand (usually "design day" demand for NGDCs), to reflect the fact that each main must be sized to be able to meet the peak demands of downstream customers under extreme weather condiditons. In the past, the Company would segregate its mains by operating pressure, and then would both classify and allocate those costs separately based on the loads served through those systems. As explained by Mr. Notestone, the Company is no longer segregating costs by operating pressure.[16]

The Company's "P&A" model allocates all mains costs based on a 50/50 weighting of average demand (which is arithmetically equivalent to annual throughput) and design day peak demand. Advocates for this method argue that there are no scale economies to attaching and serving larger customers, and that a portion of mains costs are causally related to annual throughput. Heretofore, the Company's P&A ACOSS model would, like the CD model, segregate mains costs by operating pressure for classification and allocation.

The Company's "AVG" model is a simple average of these two methods. It should be recognized that the Company's two methods produce enormously divergent results.

In the Company's last base rates case, however, Pennsylvania Office of Consumer Advocate ("OCA") Mr. Jerome D. Mierzwa generally argued that (a) the results of the CD method were irrelevant to cost causation, and (b) segregating mains costs by operating pressure was not appropriate (except for mains operating at transmission pressure). The Commission approved Mr. Mierzwa's approach. The Company indicates that it now conceptually agrees with Mr. Mierzwa that there is no need to segregate mains by operating pressure, although Mr. Notestone argues that this change is justified by the Company's mains replacement program which allows smaller customers to be served from higher pressure plastic pipe.

As I indicated earlier, mains costs allocated to the MDS class are not affected by these alternative allocation methods. MDS customers are either attached directly to the interstate pipeline system or are in close physical proximity. The cost for the mains used to supply these customers are directly assigned to that class, and thus are the same in all ACOSS model simulations.

The Company indicates that it generally relies on the P&A ACOSS for revenue allocation and rate design in this proceeding, although the Company appears to believe that the results of the CD ACOSS have some relevance.

[16] Columbia Statement No. 11 at 8.

Q. What approach do you take for cost allocation in this proceeding?

A. While I disagree with the Commission's findings regarding mains cost allocation in the last case, I accept the method employed by the Company in its P&A ACOSS for reasons of Commission precedent. Litigating this issue annually (or biennially) serves no useful purpose. The issue at hand is to incorporate the implications of that decision into rates as quickly as is practicable, subject to the constraints of rate gradualism.

As a practical matter, I replicated the results of the Company's P&A ACOSS in my own version of the ACOSS. Because the Company's method generally appears to be consistent with that used in the last case, and because that method was approved by the Commission just four months ago, I did not conduct a detailed review of the methods or the supporting allocation factors. I accept the Company's P&A ACOSS for the purposes of revenue allocation and rate design in this proceeding. My working version of this model is attached as RDK WP2, which includes supporting revenue allocation analyses. Table IEc-2 below summarizes the results of that ACOSS model for the various rate classes.

Table IEc-2
Summary Results of Columbia Gas P&A ACOSS at Present Rates ($000)

	Current Rate Revenues*	Rate of Return	Present Rates Subsidy	Subsidy Percent
Residential	$362,965	6.5%	$31,074	8.6%
SGS1	$ 40,308	5.6%	$ 1,248	3.1%
SGS2	$ 44,457	5.9%	$ 2,826	6.4%
Medium General	$ 26,637	4.9%	($623)	-2.3%
Large General	$ 19,696	0.9%	($12,324)	-62.6%
MDS	$ 1,109	157.5%	$1,026	92.6%
Flex	$ 3,392	-4.4%	($23,229)	-684.8%
Total	**$498,564**	**5.2%**	--	--

A positive cross-subsidy value indicates that the class over-recovers costs at current rates; a negative value indicates that the class receives a subsidy.

* Excludes allocated other revenues.

Source: RDK WP2

Q. Have you made any further calculations regarding cost allocation?

A. Yes. As shown in Table IEc-2, the subsidies provided to the flex rate customer group at current rates dwarf the class' current revenues and represent by far the largest revenue shortfall of any rate class group. Flex customer revenues amount only to about $3.4 million, whereas costs allocated to that customer group are $26.6 million and present rates and $32.9 million at proposed rates.

However, as I explained earlier, the Company claims that the current rate revenues represent the maximum amount that can be earned from these customers. Thus, the $23.2 million shortfall from this class, plus this class' share of the proposed rate increase, must be recovered from the other rate classes. To provide useful cost allocation results for revenue allocation, I reallocated this shortfall to the other rate classes. Because the costs allocated to the flex rate customers are dominated by mains plant, it can reasonably be inferred that the unrecovered costs are mains-related.[17] I therefore reallocated the flex rate shortfall to the other rate classes using the P&A mains allocation factor. The ACOSS results with this reallocation are shown in Table IEc-3 below:

[17] Mains represent over 90 percent of the utility plant assigned to the flex rate customer group. See RDK WP2.

Table IEc-3
Summary Results of Columbia Gas P&A ACOSS at Present Rates ($000)
With Flex Rate Shortfall Reallocated

	Current Rate Revenues*	Subsidy	Subsidy Percent
Residential	$362,964	$17,863	4.9%
SGS1	$ 40,308	($ 937)	-2.3%
SGS2	$ 44,457	($ 287)	-0.6%
Medium General	$ 26,637	($2,763)	-10.4%
Large General	$ 19,696	($14,901)	-75.7%
MDS	$ 1,109	$1,025	92.5%
Flex	$ 3,392	--	--
Total	**$498,564**	--	--

A positive cross-subsidy value indicates that the class over-recovers costs at current rates; a negative value indicates that the class receives a subsidy.

* Excludes allocated other revenues.

Source: RDK WP2

Table IEc-3 indicates that the Residential class is modestly over-recovering costs, the small to medium general service classes moderately under-recover costs, and the large general service class substantially under-recovers allocated cost.[18] In particular, note that the subsidy to the Large General (Rate LDS) customer class represents more than 75 percent of current rate revenues. Thus, to move revenues in line with costs for that class, a rate increase of 75 percent plus the effect of the general base rates increase would need to be imposed.

[18] As I indicated earlier, the MDS class consists of large customers located in close proximity to interstate pipelines, and mains costs are directly assigned to these customers. These customers have historically provided a cross-subsidy to the other classes, generally because rate decreases have not been applied to reduce rates to allocated. The Company proposes to continue this practice in this proceeding, by assigning a zero increase to the class.

5. Revenue Allocation

Q. What is revenue allocation?

A. Revenue allocation is the assignment of the dollar net increase or decrease to each of the Company's rate classes in a base rates proceeding. In contrast, *rate design* determines how the allocated revenue is recovered from individual ratepayers within each class. From a cost recovery standpoint, revenue allocation addresses *inter-class* cross-subsidization issues, while rate design addresses *intra-class* cross-subsidization issues.

Q. What are the primary economic and regulatory criteria for revenue allocation?

A. In general, allocated cost is the primary criterion used by regulators in the revenue allocation process. Most utilities and regulators adopt a policy in a base rates proceeding of attempting to move revenues more into line with allocated costs by varying the magnitude of the rate increases for the individual classes. However, regulators also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue allocation process are:

- the *gradualism* principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customers are avoided; and
- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand. [19]

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. With this proposal, the ACOSS can be simulated at both present and proposed rates to evaluate the magnitude of "progress" has been made toward the policy of achieving cost-based rates.

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[19] See, for example, Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. The criteria in this text apply to the overall development of a utility rate structure. The criteria that I discuss in this testimony are those that apply to the revenue allocation portion of the process, which is only one aspect of the overall development of utility rates.

Q. Please summarize the process used by Columbia for its proposed revenue allocation in this proceeding.

A. Mr. Notestone indicates that the Company's goal is to move class revenues more into line with allocated costs. He also indicates that the results of the alternative ACOSS models provide a "zone of reasonableness" for that evaluation, and that the Company gave "primary consideration" to the P&A ACOSS method (explicitly approved by the Commission just four months ago). Mr. Notestone also indicates that the Company set an upper limit for base rate increases at 1.5 times the proposed system average increase of 19.9 percent, or 29.9 percent. As a measure of progress toward cost-based rates, Mr. Notestone indicates that the Company relies on the indexed rate of return metric at present and proposed rates.

Q. Please comment on the Company's use of the indexed rate of return metric for evaluating progress toward cost-based rates.

A. The indexed rate of return metric is derived as the ratio of the class rate of return on rate base to the systemwide average return on rate base. Thus, for example, if a rate class is earning 2 percent on rate base at current rates and the system average is 5 percent, the indexed rate of return metric is 2.0/5.0 = 0.4. The metric correctly indicates that this class is under-recovering costs. As a measure of progress, however, the indexed rate of return metric overstates progress toward cost-based rates, and it can falsely show progress when none exists. For example, the indexed rate of return metric will show that an across-the-board rate increase results in progress toward cost-based rates, when in fact such an increase necessarily produces zero progress toward cost-based rates.[20] As such, the indexed rate of return metric should not be used to measure progress toward cost-based rates.

The Commission has recently addressed this concern. In an order involving the City of Bethlehem – Water Department, the Commission concluded:

> "As noted by the OSBA, the proper yardstick for measuring the degree of movement toward cost of service is the change in the absolute level of class subsidies at present and proposed rates."[21]

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[20] See RDK WP2 "Indexed RoR" worksheet for a numerical example demonstrating this result.

[21] *Pennsylvania Public Utility Commission v. City of Bethlehem -- Water Department*, Docket No. R-2020-3020256,

I have therefore relied on the dollar value of subsidies at present and proposed rates in evaluating the progress toward cost-based rates for revenue allocation in this proceeding. In so doing, however, I note that this metric can also be misleading.

As a general rule, if a rate class that is under-recovering costs at present rates is assigned an above-average system increase, the revenues for that class are moving more into line with allocated cost. However, the subsidy metric used by the Commission may indicate that the class subsidy in dollar terms is increasing, even if a class that is currently receiving a subsidy is assigned an above-average increase.[22] That is, the subsidy to the class in question may increase in dollar terms, even if it is decreasing as a percentage of base rates.

Thus, for this proceeding, I considered both dollar value of cross subsidies and the revenue-cost ("R-C") ratio metric. The "R-C" metric represents (unsurprisingly) the ratio of class revenues to class allocated costs, and thus implicitly recognizes the subsidy as a percentage of the class revenue requirement.

Q. Please summarize the Company's revenue allocation proposal in this proceeding, using these metrics.

A. Table IEc-4 below shows the Company's revenue allocation proposal. The first three columns show the Company's proposed percentage increase, compared to the present-rates dollar subsidy and R-C metrics. In general, the Company's revenue allocation proposal is directionally reasonable, in that classes that currently receive a subsidy, and which have a R-C ratio below 100 percent, are assigned above-average increases.[23] In particular, excluding MDS and Flex rate classes, the Residential class is currently providing a subsidy to the other classes, and it is assigned a below-average rate increase. The regular non-residential classes are receiving a subsidy, and are assigned above average increases.

Order entered April 15, 2021, at 36.

[22] See RDK WP2, "Indexed RoR" worksheet.

[23] The MDS class is assigned a zero increase, consistent with past practice. For the reasons discussed earlier,

The two right-hand-side columns show the dollar subsidy and R-C ratios at proposed rates. I have shaded the cells where the metric shows progress toward cost-based rates.

Table IEc-4
Columbia Gas Revenue Allocation Proposal

		Current Rates		**CPA Proposed Rates**	
	Increase %	**Subsidy**	**R-C Ratio**	**Subsidy**	**R-C Ratio**
Residential	18.6%	17,863	106.3%	21,942	105.4%
SGS1	21.0%	((37)	96.3%	(1,327)	97.3%
SGS2	20.5%	(287)	96.3%	(1,662)	97.0%
Med Gen'l (SDS/LGSS)	26.3%	(2,763)	87.7%	(2,716)	92.5%
Lg Gen's (LDS/LGSS)	29.9%	(14,901)	55.0%	(17,243)	59.7%
MDS	0.0%	1,025	1310.5%	1,007	1095.0%
Flex	0.4%	--	NM	--	NM
Total	**19.7%**	**--**	**100.0%**	**--**	**100.0%**

A positive cross-subsidy value indicates that the class over-recovers costs at current rates; a negative value indicates that the class receives a subsidy.

Subsidies and R/C ratios are calculated after reallocation of Flex rate customer shortfall.

Source: RDK WP2

As shown in Table IEc-4, the dollar value of cross-subsidies actually increase under the Company's proposal for most rate classes, despite the fact that the Company's revenue allocation proposal is directionally reasonable. When subsidies are measured on a percentage basis using the R-C ratio metric, the Company's revenue allocation proposal shows progress toward cost-based rates for all classes except the Flex rate customers.

Q. Do you agree with the Company's revenue allocation?

A. The Company's proposal is not obviously unreasonable. I evaluated numerous scenarios in an attempt to develop a balanced approach that would result in a decrease in the dollar value of subsidies, as mandated by the Commission in *City of Bethlehem*. However, these scenarios involved rate increases for the Large General and Medium General service classes that substantially exceeded increases that could reasonably be assigned within the bounds of rate gradualism.

However, I do recommend that the Commission consider a modification to the Company's proposal, in order to achieve more progress toward cost-based rates and to reasonably reflect its cost allocation decision in the last base rates case.

As shown in Table IEc-4, the dollar cross-subsidy to the Large General Service (LDS/LGSS) class actually increases by more than $2 million under the Company's proposal, while the R-C ratio implies only very small progress toward cost-based rates. This lack of progress is effectively caused by the Company's constraint of a 1.5 times system average increase as an upper bound for rate gradualism. While I acknowledge that the 1.5 factor is often used in Pennsylvania, the specific circumstances in this case suggest that a higher upper bound may be appropriate, for a couple of reasons. First, because the cost recovery for Large General service is so extremely low that it will take many rate proceedings to move rates into line with allocated cost if the 1.5 times system average factor is applied. As shown in Table IEc-4 above, progress toward cost-based rates for this class is minimal at best, and it will be further reduced if the overall rate increase is scaled back. Perpetuating the cross-subsidy to this class is not consistent with ratemaking principles, and it is not consistent with the Commission's decision on cost allocation. Second, the distribution rates for this class measured on a per-Dth basis are quite low. On a per-Dth basis, the Company's proposed increase for the Residential class is $1.95 per Dth, for SGS1 it is $1.49 per Dth, and for Large General it is $0.53 per Dth. Thus, while the percentage impact is large, the cost per Dth is relatively modest.

I therefore recommend that the Commission consider shifting $1.8 million from the Residential class increase to the Large General Service class. In addition to the need to move Large General Service rates more into line with allocated cost, I observe that the Company's proposal resulted in less progress toward cost-based rates than for the other classes, as measured by the R-C ratio.[24] The results of that proposal are shown in Table IEc-5 below.

[24] See RDK WP2.

The increase to the Large General Service is a little below 2.0 times the system average increase (which is also a rule-of-thumb for rate gradualism). On a per-Dth basis, the increase to the LDS class would be approximately $0.69 per Dth, still well below the unit cost increases to the Residential and SGS rate classes. As shown in Table IEc-5, this proposal will result in at least modest progress toward cost-based rats for the Large General Service rate class using the R-C ratio metric.

Table IEc-5
RDK Alternative Revenue Allocation Proposal

		Current Rates		CPA Proposed Rates	
	Increase %	**Subsidy**	**R-C Ratio**	**Subsidy**	**R-C Ratio**
Residential	18.1%	17,863	106.3%	20,142	104.9%
SGS1	21.0%	((37)	96.3%	(1,327)	97.3%
SGS2	20.5%	(287)	96.3%	(1,662)	97.0%
Med Gen'l (SDS/LGSS)	26.3%	(2,763)	87.7%	(2,716)	92.5%
Lg Gen's (LDS/LGSS)	39.9%	(14,901)	55.0%	(15,443)	63.9%
MDS	0.0%	1,025	1310.5%	1,007	1095.0%
Flex	0.4%	--	NM	--	NM
Total	**19.7%**	**--**	**100.0%**	**--**	**100.0%**

A positive cross-subsidy value indicates that the class over-recovers costs at current rates; a negative value indicates that the class receives a subsidy.

Subsidies and R/C ratios are calculated after reallocation of Flex rate customer shortfall.

Source: RDK WP2

6. **<u>Rate Design Issues</u>**

Q. Please describe the tariff structure for the SGSS, SCD and SGDS rate classes.

A. Base rate tariff charges for these three classes currently consist of a bifurcated monthly customer charge and a bifurcated commodity charge, both split between customers with annual consumption above and below 644 Dth. Within each size category, SGSS and SCD customers pay the same commodity charge, while SGDS customers pay a slightly lower commodity charge reflecting the fact that the Company does not incur gas storage working capital costs for regular transportation customers. The basic distribution rate tariff structure is shown in Table IEc-6 below.

In addition, the SGSS sales customers are subject to PGC, GPC, MFC and Rider CC charges. Rate SCD Choice and Rate SGDS transportation customers are subject to certain PGC charges (related to load balancing), and the Rider CC charge.

Q. How does Columbia propose to implement its rate increase for these classes?

A. Columbia's proposed increases for the base rates components of Small General Service classes are shown in Table IEc-6 below.[25] The Company has essentially proposed to assign class-average increases to both the customer charge and the commodity charge for each class. In effect, the Company proposes no change to rate design for these classes.

Table IEc-6
Columbia Proposed Small General Service Base Rate Design

	Current Rate	Proposed Rate	Percent Increase
Rates SGSS and SCD			
Customer Charge < 644Dth/year	$26.00	$31.50	21.2%
>644 Dth/year	$55.00	$66.00	20.0%
Commodity Charge <644 Dth/year	$5.3932	$6.5197	20.9%
>644 Dth/year	$4.5596	$5.4799	20.2%
Rate SGDS			
Customer Charge < 644Dth/year	$26.00	$31.50	21.2%
>644 Dth/year	$55.00	$66.00	20.0%
Commodity Charge <644 Dth/year	$5.2843	$6.4348	21.8%
>644 Dth/year	$4.4514	$5.3949	21.2%

[25] Table Iec-6 shows the Company's proposed rate design as detailed in Exhibit 103 Schedule 7, which appears to be consistent with the proposed revenues reported in the Company's ACOSSs. These values do not appear to be consistent with the testimony of Columbia witness Melissa J. Bell (Statement No. 3) at pages 36-37.

Q. What approach do you recommend for setting rates for these classes?

A. For small and medium general service classes, I generally advocate setting the customer charge at or only modestly below the customer-related costs for the smaller customers within each class, subject to rate gradualism constraints. Columbia Gas appears to agree with this approach. Mr. Notestone indicates, *"In essence, customer-related costs that bear no relationship to customer gas consumption patterns should be recovered through the fixed portion of the rate design, i.e. the monthly customer charge."*[26] The commodity charge is then adjusted to produce the appropriate revenue requirement.

The Commission's decision regarding the appropriate cost allocation methodology has an impact on the cost basis for the customer charge, particularly for the non-residential rate classes. In the past, when some portion of mains were seen as having a customer component to costs, I included those costs in my derivation of the cost basis for non-residential customer charges. In the P&A ACOSS method, no mains costs are classified as customer-related, which reduces the cost basis for the customer charge. As detailed below, this cost allocation change constrains the magnitude of the customer charge increase for some non-residential rate classes. While Columbia may continue to believe that mains have a customer cost component for rate design purposes, the Commission does not.

Q. How do you determine the cost basis for the customer charge?

A. I begin with my replicated version of the Company's P&A ACOSS model, which separately tracks customer-related costs. In developing the cost basis for the customer charge, I take a relatively simple approach to the problem, in that I include all costs that are allocated on a customer basis in the ACOSS model. I recognize that some experts, and at least some Commission precedent, support the exclusion of certain "indirect" customer-related costs from this calculation, particularly for residential customers. Nevertheless, I follow the basic principle that the rates should follow the costs. If customer charges are set below the allocated customer cost, then larger customers will subsidize smaller customers, as measured by the logic of the ACOSS. While subsidizing smaller customers may have a public policy

[26] Columbia Statement No. 11 at 21.

rationale for the residential class, I see no particular advantage to such an intra-class cross-subsidy for the non-residential classes.

In making the calculations, I *excluded* uncollectibles costs from customer-related costs. Uncollectibles costs are essentially a fee on customers who pay their bills to compensate the utility for those customers who do not. As these costs are essentially a tax, I deem it reasonable to recover these costs with volumetric charges within the small business classes. This approach is conceptually similar to the Company's treatment of universal service costs within the Residential class.

This analysis is detailed in RDK WP2, in the "Customer" worksheet.

Q. What are the implications of your analysis for the SGS/SGDS customer class customer charges?

A. As detailed in RDK WP2, my customer cost analysis shows that the SGS1 customer cost is just under $37, which is moderately above the Company's proposed increase to $31.50. As a check, I compared the Company's proposed charge with those of other Pennsylvania NGDCs in Table IEc-7 below.

For SGS2, however, my analysis shows a customer cost of $57.19, which is only slightly above the current customer charge of $55.00, and below the Company's proposed $66.00 charge. Based on the cost analysis, I therefore recommend that any increase to the SGS2 customer charge be no more than $2 at proposed rates, and it should be scaled back with any reduction in the class revenue requirement. A zero increase for this customer charge would also be reasonable.

Q. How does the Company's proposed customer charge for the SGS1 customers compare to the practices of other Pennsylvania NGDCs?

A. Table IEc-7 below presents the customer charges. As shown, Columbia's customer charges for small commercial customers are among the highest in the Commonwealth. Of course, since Columbia's overall rates for small commercial customers are also among (or at) the highest in the Commonwealth, this finding is not surprising.

Table IEc-7 Non-Residential Customer Charges: Pennsylvania NGDCs	
	$/month
National Fuel Gas Dist'n C&PA (< 250 mcf)	$19.89
Peoples Natural Gas SGS (< 500 mcf)	$20.00
UGI Gas N/NT	$23.50
PGW GS-C	$24.00
Columbia Gas SGSS/SCD/SGDS (Current)	**$26.00**
PECO Gas GC	$28.55
Columbia Gas SGSS/SCD/SGDS (Proposed)	**$31.50**
Peoples Gas (TWP) SGS (<500 mcf)	$40.00
Sources: RDK WP1 "Rate Comp" worksheet.	

In light of this comparison across NGDCs, I conclude that the Company's proposal for the customer charge for the SGS1 class is not unreasonable, despite being below allocated cost.

Q. Did you review the proposed customer charge for any other rate classes?

A. I reviewed the Medium General (SDS/LGSS) class customer charge. My cost analysis shows a customer-related cost of $233 per month, compared to the current customer charge of $265 and a proposed charge of $335. Based on the cost analysis, I recommend that no increase be assigned to the SDS/LGSS customer charge in this proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

ROBERT D. KNECHT PRINCIPAL

Overview

Mr. Knecht has more than 35 years of practical economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 25 years, Mr. Knecht's practice has primarily involved providing analysis, consulting support and expert testimony in regulatory matters, primarily involving electric and natural gas utilities. Mr. Knecht's work includes many aspects of utility regulation, including industry restructuring, cost unbundling, cost allocation, rate design, rate of return, customer contributions, energy efficiency programs, smart metering programs, treatment of stranded costs and utility revenue requirement issues. He has worked for state advocacy agencies, industrial customer groups, law firms, regulatory agencies, government agencies and utilities, in both the United States and Canada. He has provided expert testimony in more than one hundred separate utility proceedings.

In addition to his work with regulated utilities, Mr. Knecht has consulted on international industry restructuring studies, prepared economic policy analyses, participated in a variety of litigation matters involving economic damages, and developed energy industry forecasting models.

Education

Master of Science, Management (Applied Economics and Finance), Sloan School of Management, M.I.T.

Bachelor of Science, Economics, Massachusetts Institute of Technology

Select Project Experience

For more than twenty years, Mr. Knecht has provided consulting services, analysis and expert testimony before the Pennsylvania Public Utility Commission on all manner of regulatory proceedings to the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**. In addition to expert testimony, Mr. Knecht has assisted OSBA with the development of public policy positions, litigation strategy, and longer term strategy.

For the **INDUSTRIAL GAS USERS ASSOCIATION**, Mr. Knecht provided consulting and expert witness services in a generic cost allocation proceeding involving Gaz Métro before the Régie de l'énergie in Québec.

For the **NEW BRUNSWICK PUBLIC INTERVENER,** Mr. Knecht provides consulting and expert witness services in a variety of regulatory proceeding before the New Brunswick Energy and Utilities Board involving New Brunswick Power, Enbridge Gas New Brunswick, and petroleum products. Mr. Knecht has addressed issues of load forecasting, costs forecasting, cost of capital, allocation of corporate overhead costs, utility cost allocation, revenue allocation, market-based rate design, cost-based rate design, and rate decoupling.

For **L'ASSOCIATION QUÉBÉCOISE DES CONSOMMATEURS INDUSTRIELS D'ÉLECTRICITÉ (AQCIE) AND LE CONSEIL DE L'INDUSTRIE FORESTIÈRE DU QUÉBEC (CIFQ)**, Mr. Knecht provided analysis, consulting advice and expert testimony before the Régie de l'énergie in regulatory matters involving Hydro Québec Distribution and TransÉnergie. This work includes revenue requirement, power purchasing, cost allocation, treatment of cross-subsidies, and rate design.

For the **INDEPENDENT POWER PRODUCERS SOCIETY OF ALBERTA**, Mr. Knecht provided consulting advice, analysis and expert testimony before the Alberta Energy and Utilities Board in a series of proceedings involving the restructuring of the electric utility industry, the unbundling of rates, and the development of transmission rates.

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ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2016-2580030	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	April 2017	Pennsylvania Office of Small Business Advocate	Test year, load forecast, O&M expenses, rate base, rate of return, cost allocation, rate design, EE&C program, capacity assignment
Matter 336	New Brunswick Energy & Utilities Board	New Brunswick Power	January 2017	New Brunswick Public Intervener	Financial forecast, equity requirement, depreciation life, variance mechanisms, cost allocation, rate design
Matter 338	New Brunswick Energy & Utilities Board	Generic	December 2016	New Brunswick Public Intervener	Retail petroleum margins
Matter 330	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2016	New Brunswick Public Intervener	Revenue requirement, investment test, customer retention initiatives, cost allocation, rate design
R-2016-2537359	Pennsylvania Public Utility Commission	West Penn Power Company	July 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-2016-2537355	Pennsylvania Public Utility Commission	Pennsylvania Power Company	July 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
P-2016-2537609, 2537594	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas	July 2016	Pennsylvania Office of Small Business Advocate	Waiver of DSIC cap.
P-2016-2543523	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Electric Division	July 2016	Pennsylvania Office of Small Business Advocate	Default service procurement.
R-2016-2529660	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	June 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-2015-2469275	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	May 2016	Pennsylvania Office of Small Business Advocate	Default service procurement plan.
R-2015-2518438	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Gas Division	April 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, energy efficiency and conservation program.

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-2016-2521993	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	April 2016	Pennsylvania Office of Small Business Advocate	Waiver of DSIC cap.
M-2015-2477174	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Electric Division	February 2016	Pennsylvania Office of Small Business Advocate	Energy efficiency and conservation plan review and development.
Matter No. 306	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	February 2016	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2015-2511333, 2511351, 2511355, 2511356	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2016	Pennsylvania Office of Small Business Advocate	Default service procurement plans, purchase of receivables.
P-2015-2501500	Pennsylvania Public Utility Commission	Philadelphia Gas Works	October 2015	Pennsylvania Office of Small Business Advocate	DSIC rate design under cash flow regulation, capital structure
P-2014-2459362	Pennsylvania Public Utility Commission	Philadelphia Gas Works	June 2015	Pennsylvania Office of Small Business Advocate	Demand side management programs, rate decoupling mechanism, incentive mechanism, cost-benefit analysis.
R-2015-2469275	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2015	Pennsylvania Office of Small Business Advocate	Misc. revenue requirement issues, cost allocation, rate design
R-2015-2468056	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2015	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, customer contribution policy
R-2015-2461373	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	April 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-2014-2456648	Pennsylvania Public Utility Commission	Peoples TWP LLP	March 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-3867-2013	Régie de l'énergie, Québec	Société en commandite Gaz Métro	February 2015	l'Association des Consommateurs de Gaz	Distribution cost allocation

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-3888-2014	Régie de l'énergie, Québec	Hydro Québec TransÉnergie	December 2014	AQCIE/CIFQ	Transmission customer contribution policy
R-2014-2428744 R-2014-2428742	Pennsylvania Public Utility Commission	Pennsylvania Power Company, West Penn Power Company	November 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
M-2014-2430781	Pennsylvania Public Utility Commission	PPL Electric Utilities	October 2014	Pennsylvania Office of Small Business Advocate	Smart meter procurement, rate design
Matter No. 253	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2014-2417907	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, class eligibility, reconciliation
R-2014-2406274	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2407345	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Customer contribution policy, alternative financing mechanism
R-2014-2408268	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2014	Pennsylvania Office of Small Business Advocate	Gas procurement sharing mechanism, cost allocation
R-2014-2397237	Pennsylvania Public Utility Commission	Pike County Light & Power (Electric)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2397353	Pennsylvania Public Utility Commission	Pike County Light & Power (Gas)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation
R-2014-2399598	Pennsylvania Public Utility Commission	Peoples TW Phillips	March 2014	Pennsylvania Office of Small Business Advocate	Gas procurement, design day demand, cost allocation rate design, retainage
P-2013-2389572 (Remand)	Pennsylvania Public Utility Commission	PPL Electric Utilities	February 2014	Pennsylvania Office of Small Business Advocate	Time of use rates, net metering rates

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter 225	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	January 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2013-2391368, P-2013-2391372, P-2013-2391375, P-2013-2391378	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, cost allocation, rate design
Matter No. 214	New Brunswick Energy & Utilities Board	Generic	November 2013	New Brunswick Public Intervenor	Maximum retail margins for motor fuel and residential heating oil.
Matter No. 171	New Brunswick Energy & Utilities Board	New Brunswick Power	September 2013	New Brunswick Public Intervenor	Amortization method for deferral costs associated with refurbishing Point Lepreau Generating Station
C-2013-2367475	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2013	Pennsylvania Office of Small Business Advocate	Forecasting and reconciliation of default service electric costs and revenues.
P-2011-2277868, I-2012-2320323	Pennsylvania Public Utility Commission	Generic	August 2013	Pennsylvania Office of Small Business Advocate	Ratemaking treatment for customers in overlapping NGDC service territories (“gas-on-gas”).
P-2013-2356232	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Program design, cost recovery and rate design for alternative system expansion financing pilot program (“GET Gas”)
R-2013-2355886	Pennsylvania Public Utility Commission	Peoples TWP LLC	July 2013	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2013-2361764, R-2013-2361763, R-2013-2361771	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas.

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EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter No. 178	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	July 2012	NB Public Intervenor	System expansion economic test, test year revenue requirement, cost allocation, rate design, treatment of stranded costs.
R-2012-2290597	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2012	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2012-2293303	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2012	Pennsylvania Office of Small Business Advocate	Treatment of pipeline credits
AUC ID #1633	Alberta Utilities Commission	Alberta Electric System Operator	April 2012	Powerex, Northpoint Energy Solutions, Cargill	Economic efficiency issues for allocation of constrained transmission capacity.
R-2012-2286447	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, reconciliation
R-2012-2281465	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, gas price procurement and hedging
R-2011-2273539	Pennsylvania Public Utility Commission	Peoples TWP	March 2012	Pennsylvania Office of Small Business Advocate	Design day demand methodology
P-2011-2273650 P-2011-2273668 P-2011-2273669 P-2011-2273670	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	February 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, retail market enhancement, rate design.
R-2011-2264771	Pennsylvania Public Utility Commission	PPL Electric Utilities	January 2012	Pennsylvania Office of Small Business Advocate	TOU Rates

Note: Dates shown reflect submission date for direct testimony.

May 2017

EXHIBIT IEc-2

RDK ELECTRONIC WORKPAPERS

RDK WP1: Columbia Proposed Proof of Revenues

RDK WP2: Replication of Columbia P&A ACOSS

Workpapers will be transmitted via separate e-mail attachment simultaneous to e-mail service of this document

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2021-3024296**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits IEc-1 through IEc-2 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: June 16, 2021

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3024296**
	:	
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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DATE: June 16, 2021

/s/ Steven C. Gray

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Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

UGI Gas Exhibit SAE-4R

UGI Utilities, Inc. - Gas Division
Rate MBS and NNS

MBS Revenue ($) by Month (Fiscal Years 2020 & 2021)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 2020	62,120	95,699	141,863	160,006	137,222	139,014	109,245	89,770	98,119	97,902	106,941	95,584
FY 2021	117,915	126,573	139,165	145,127	134,411	125,062	102,847	96,347	88,123	89,000	90,641	89,792

NNS Revenue ($) by Month (Fiscal Years 2020 & 2021)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 2020	67,033	76,601	92,792	98,420	87,490	91,915	77,702	68,724	74,689	66,026	72,016	69,401
FY 2021	82,794	65,174	65,234	64,321	67,475	65,757	64,999	65,421	66,722	66,846	66,084	67,414

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 9-R

Rebuttal Testimony of
Timothy J. Angstadt

PROPRIETARY VERSION

Topics Addressed:	**Increased Operating Costs** **Restoration Costs** **Leak Reductions**

Dated May 17, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy J. Angstadt. My business address is One UGI Center, Wilkes Barre, Pennsylvania 18711.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 9, on January 28, 2022.

Q. What is the purpose of your testimony?

A. My rebuttal testimony responds to the direct testimony submitted by the Bureau of Investigation and Enforcement ("I&E"): I&E Statement No. 6, the direct testimony of Jessalynn Heydenreich. I also address the results from three recent request for proposals ("RFPs") that will increase the Company's operating costs for the FPFTY.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring UGI Gas Exhibits TJA-1R and TJA-2R.

II. INCREASED OPERATING COSTS

Q. Have there been any changed circumstances since the filing of your direct testimony that impact this case?

A. Yes, UGI Gas received the results from three RFPs for pipeline construction and maintenance, restoration, and traffic control services contained within a Master Pipeline Construction Agreement ("MPCA"), Master Restoration Services Agreement ("MRSA"), and the Master Pipeline Support Services Agreement ("MPSSA") (collectively the "2022 RFP"). The results of the 2022 RFP reflect the significant impact of inflation on all parts of the Company's operations, both on contractor costs that affect pipeline replacement and restoration activities and on activities that drive operations and maintenance expense.

Q. Please describe the Company's use of contractors for its main replacement and other maintenance activities.

A. UGI Gas utilizes contractor resources to perform construction and maintenance activities on the natural gas distribution system, including main and service line replacement, valve inspections, leak repairs, spotting facilities, corrosion mitigation, traffic control, sidewalk and roadway restoration, and others.

Q. How are contractors selected to perform work at UGI Gas?

A. UGI Gas utilizes a competitive bid process, typically on a three-year cycle, and awards blanket style construction agreements to multiple incumbent and incremental contractors who bid on each region. The contracts are awarded based on key factors of price, capability, and safety record. Using this process, UGI Gas was successful in maintaining consistent costs for a majority of the pipeline construction contractors from 2018 until the most recent RFP in the spring of 2022, with only nominal increases where price adjustments did occur.

Q. Please describe the 2022 RFP process.

A. UGI Gas typically uses three-year contract terms for its blanket construction contractors, although in the most recent cycle the Company extended the existing contracts for the MPCA through February 2022 in order to provide for a more robust bid process, address confusing contract items, and adopt a start date for new contracts of March 1, which aligns better with the construction season. The table below shows the critical dates for the three RFPs impacting contractor costs in this proceeding:

Table 1. Critical Dates For 2022 RFP

Category	Contract	RFP Issued	Contract Effective	Contract Expiration
Pipeline/Construction	MPCA	11/3/2021	3/1/2022	2/28/2025
Restoration	MRSA	12/3/2021	4/1/2022	3/1/2025
Traffic Control	MPSSA	9/17/2021	4/1/2022	11/1/2025

Q. Please describe the results of the 2022 RFP.

A. The results of the 2022 RFP reflect significant price increases across the range of services provided by the bidders. As intended, UGI Gas was successful in attracting several additional contractor bids throughout the various bid regions established within these contracts. On average, the count of regional contractor bids increased by over twenty percent when compared to the 2018 RFP, indicating a competitive market.

Q. What is driving the increase in prices reflected in the RFP results?

A. As discussed in Mr. Brown's rebuttal testimony, UGI Gas St. No. 1-R, inflationary pressures are impacting all elements of UGI Gas's operations. As specific to construction, the pipeline construction labor market is constrained, and the region is experiencing extremely low unemployment rates. To secure skilled labor, contractors must pay higher labor rates, and those higher rates are passed on to UGI Gas. In addition, the inflationary impacts to materials, equipment and supplies are also reflected in the bids received by the Company in response to its RFP.

Q. How do these results impact the Company's proposed cost for main replacement and other maintenance activities?

A. The Company will see both its main replacement and maintenance related capital and expense costs increase substantially as a result of the new contracts. UGI Gas witness Vicky A. Schappell (UGI Gas St. No. 5-R) addresses the anticipated increase in capital costs in her rebuttal testimony. For the FPFTY, for example, the increase in capital costs is anticipated to be $37.8 million above the amount presented by the Company when it filed this case.

Q. Have you quantified the impact of the increased contractor costs on expenses for the FPFTY?

A. Yes, the Company has quantified the impact of the increased contractor costs on its expense claim. Attached to my testimony is UGI Gas Exhibit TJA-1R. This exhibit provides the Company's response to OCA-III-33, which indicates that UGI Gas's original budget for outside contractor expense in this case for the FPFTY was $21.723 million. UGI Gas Exhibit TJA-2R shows the impact of incorporating the increased contractor costs received by the Company in the 2022 RFP, which increases outside contractor expense by $2.692 million in the FPFTY to a total of $24.416 million.

III. RESTORATION COSTS

Q. Please summarize the direct testimony of I&E witness Jessalynn Heydenreich regarding UGI Gas's costs for replacing mains.

A. Ms. Heydenreich's testimony focuses on the cost increase associated with the Company's main replacement program, and specifically the increase in restoration costs. Ms. Heydenreich states that between 2017 and 2021, UGI Gas's restoration costs increased from $159,350 per mile to $355,354 per mile, or a 123% increase. (I&E Statement No. 6 at 7 and 9.) Ms. Heydenreich asserts that if UGI Gas spent less dollars on restoration, the Company could replace additional miles of main each year. (*Id.* at 11.)

Q. What costs are included as restoration costs?

A. Restoration costs encompass both temporary and permanent restoration activities as well as all contractor labor and materials required to complete a restoration project. The Company uses a variety of different restoration types depending on permit requirements, the location, and use of the area being restored. For permanent restoration, the project options include: (1) grass (seeding and grading); (2) rail-trail; (3) macadam; (4) mill and overlay; (5) concrete; and (6) flowable fill. The overall cost of restoration for an individual project is impacted by many variables, including main size and location, complexity of the project (which impacts duration and may require temporary restoration activities), and local ordinances dictating the scope of restoration activities. This is a non-exhaustive list of variables that impact the cost of restoration on individual projects.

Q. Do you agree with Ms. Heydenreich that restoration costs have increased?

A. Yes. Restoration costs involved with replacing and retiring natural gas mains have increased steadily over the life of the Company's accelerated main replacement program articulated in its Long-Term Infrastructure Improvement Plan ("LTIIP"), which was filed in 2013.[1] UGI Gas has taken many active steps aimed at controlling restoration costs where it is possible to do so. However, there are a number of operational reasons for the increase in restoration costs and many of these are unavoidable. In addition, significant recent economic impacts have also increased restoration costs, as I will describe in my testimony, and these are anticipated to continue in throughout the FTY and FPFTY. I also note that while restoration costs have increased, the Company has successfully met or exceeded its annual mileage replacement goals as specified in its LTIIP.

Q. What factors have caused restoration costs to increase?

A. There are several operational factors that have caused restoration costs to increase. Main size, geographic location, and the type of project all affect the amount of restoration costs. Many of the Company's cast iron systems originate in dense urban areas and expand throughout cities to less densely populated areas. Since the majority of cast iron main replacement involves replacing low-pressure cast iron with medium pressure plastic piping, cast iron replacement tends to occur by replacing the outer portions of the system first and working toward the point of origin.[2] This allows the medium pressure supply points to progress more deeply into the distribution system, while the natural gas supply to

[1] The Company's Initial LTIIP consisted of Docket No. P-2013-2398833 (for the former UGI South Rate District), Docket No. P-2013-2397056 (for the former UGI North Rate District), and Docket No. P-2013-2398835 (for the former Central Rate District) and addressed the period January 1, 2014 through December 31, 2019.

[2] Historically, the UGI Gas system was constructed with cast iron mains that connected to manufactured gas plants in or near cities, with the largest diameter pipes being those closest to the plant.

the shrinking low-pressure system is maintained. With only a few years remaining in UGI Gas's cast iron replacement program, the remaining cast iron projects are now in dense urban areas, consist of large diameter mains, and are located within busy, major roadways that will require extensive excavation and restoration. All other factors being equal, by the very nature of the Company's cast iron main replacement program, the final years of cast iron main replacement would cause the cost of restoration per mile to increase.

Q. What other factors contribute to the increased cost of restoration?

A. Two major economic factors impacting the recent acceleration of restoration costs are inflation and the increased cost of labor in the current market, which I have previously described. Contractor costs for restoration activities, which are included in the overall cost of restoration work, have increased in recent years amid the tightening labor market and despite the Company's efforts to expand its pool of qualified contractors to increase competition when UGI Gas requests bids for work. In addition, recently adopted requirements from federal, state and local governments, affecting everything from reduced daily operating hours to increased paving requirements, ultimately are reflected in additional costs associated with restoration.

Q. What steps has the Company taken to address rising restoration costs?

A. UGI Gas has employed many steps during its accelerated main replacement program that are targeted at lowering restoration costs. These include coordinating replacement efforts with other street projects and using trenchless construction techniques where appropriate. In addition, the Company has in many instances challenged municipal requirements that would otherwise add to the Company's restoration costs. As an example, the Company has selectively used litigation to challenge permit fees and excessive restoration requirements. Specifically, the Company has filed legal challenges to ordinances in Lancaster, Reading, and Scranton among other jurisdictions. The Company has also met with the Gas Safety Division to collaborate on identifying the most effective means of minimizing and reducing restoration costs.

Q. How has the Company worked to manage increases to restoration costs?

A. UGI Gas has begun to utilize select pipeline contractors to perform restoration activities. Utilizing the same contractor resources for multiple components of a single project is anticipated to reduce costs and time taken for mobilization and demobilization, which is particularly important in locations where municipalities have implemented operating time restrictions. Further, combining these activities may deliver several improvements, including limiting temporary restoration and repairs, expediting permanent restoration, and improving restoration efficiency as some resources, including traffic control, may be shared with pipeline crews on select projects.

Q. Ms. Heydenreich includes estimates for UGI Gas's total restoration costs per mile for 2022 and 2023. (I&E St. No. 6 at 10-11.) Do you agree with her estimates?

A. No. I do not agree with the methodology Ms. Heydenreich uses to arrive at her estimates, and I am informed by counsel that this methodology has not been adopted by the Commission. However, I do agree that restoration costs have been rising and that it is important for UGI Gas and other utilities to continue to make efforts to control or reduce restoration costs where it is feasible to do so.

Q. Do you agree with Ms. Heydenreich that increasing restoration costs have negatively affected replacement rates (I&E St. No. 6 at 11-12)?

A. No, I do not. The Company has continued to replace the anticipated miles of main that it has projected in its LTIIPs and has even gained further acceleration since it began its LTIIP main replacement activities in 2014, reaching an all-time high of 91 miles of main replaced in 2021. Therefore, I do not agree that the Company's rate of replacement has been negatively affected by the increasing costs associated with restoration. In addition, and contrary to Ms. Heydenreich's testimony, if UGI Gas were to spend less on restoration, it would not directly translate into additional miles of main replacement, because UGI Gas is currently utilizing all available engineering, planning, construction, and inspection resources fully to accomplish its current main replacement metrics. I specifically disagree with Ms. Heydenreich's contention that her projected increase in restoration costs in the FPFTY will result in a "23% decrease" in main replacement compared to the HTY. The HTY represented a banner year for main replacement miles that greatly exceeded the Company's planned replacements. Actual replacement miles are expected to vary on a year-to-year basis given the many differing factors which influence these projects, as I have discussed above. However, the mileage reflected in the FPFTY aligns with the projections included in the Company's Commission approved Second LTIIP[3] and its overall strategy for accelerated replacement of cast iron and bare steel mains. Specifically, the Company

[3] See *Petition of UGI Utilities, Inc. – Gas Division for Approval of its Second Long-Term Infrastructure Improvement Plan*, Docket No. P-2019-3012337 (Order entered Dec. 19, 2019).

remains on target to complete all cast iron and bare steel replacement activities on or before the time periods established in UGI Gas's Initial LTIIP filed in 2013.

Q. What recommendation does Ms. Heydenreich make for reducing future restoration costs?

A. Ms. Heydenreich recommends that UGI Gas continue coordinating replacement projects with other street projects and utilizing trenchless technology where feasible. Additionally, she requests that UGI Gas perform and submit annual audit reports to the Safety Division regarding restoration costs for the ten largest projects in the prior three years. The report should identify "costs incurred in excess of the Pennsylvania Department of Transportation restoration standards including: paving, shoulders, sidewalks, etc., and permitting fees." (I&E St. No. 6 at 12.)

Q. Do you agree with this recommendation?

A. Yes, I do. As I stated previously, UGI Gas intends to continue its efforts to control restoration costs by coordinating projects where it can and using technology that will reduce restoration activities, as well as taking other actions that may reduce cost increases associated with restoration. Further, the Company will prepare and submit an annual report to the Gas Safety Division on March 1 identifying its ten most expensive restoration projects per year over the past three years with the cost breakdowns identified by Ms. Heydenreich.

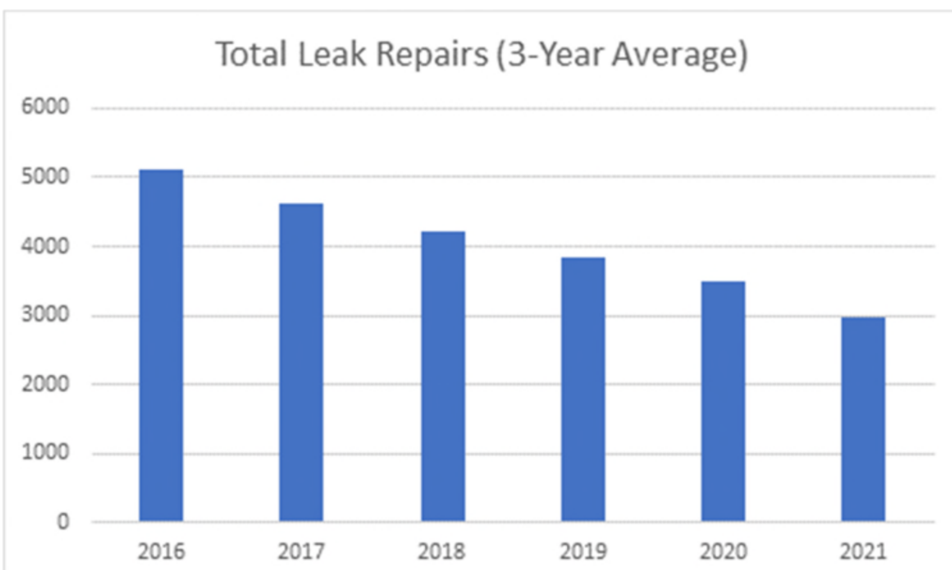
IV. LEAK REDUCTIONS

Q. Ms. Heydenreich states that between 2020 and 2021, UGI Gas experienced a small increase in the total number of leaks. (I&E St. No. 6 at 13.) Can you explain why leaks increased between 2020 and 2021?

A. Leak survey cycles are not consistent across all asset types, with some assets surveyed on three-, four-, or five-year intervals. Since some assets have higher leak rates than others and UGI Gas's entire inventory of assets are not surveyed annually, some volatility of total annual leaks found or repaired is expected. To mitigate the volatility introduced by varied leak survey cycles, UGI Gas often views leak trends on a three-year average basis, with the results shown in Figure 1. This summary clearly indicates the favorable impact of UGI Gas's accelerated main replacement program on system leakage.

[BEGIN CONFIDENTIAL]

Figure 1. Total Leak Repairs Using 3-Year Average



[END CONFIDENTIAL]

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Q. Based on the small increase identified by I&E, Ms. Heydenreich recommends that UGI Gas perform and present to I&E Pipeline Safety a root cause analysis to determine why leaks did not decrease despite the Company's accelerated main replacement program and to ensure that main replacement activities represent a prudent investment. (I&E St. No. 6 at 13-14.) What is the Company's response to this proposal?

A. UGI Gas continuously reviews its leak data and assesses changes in its data to ensure that it is proactively identifying potential areas of concerns and investing capital in the areas of greatest risk, and annually conducts a Distribution Integrity Management Plan ("DIMP") audit that is presented to PUC safety personnel for review and discussion. However, it is reasonable to anticipate some variation in leak data based on operational impacts to the system such as colder than normal weather, line strikes, etc. Although active and historical leakage are considered as elements within an asset's risk profile, total risk is utilized to prioritize assets for replacement. This risk-based asset replacement methodology may not prioritize the most leak-prone assets, and when combined with the leak survey-induced volatility described above, UGI Gas does not believe the modest increase in leaks from 2020 to 2021 requires additional analysis. However, UGI Gas is certainly willing to meet with PUC safety personnel to discuss the detailed leak survey results and trends and address any questions or recommendations that PUC safety personnel may have.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit TJA-1R

UGI Utilities, Inc - Gas Division
Before the Pennsylvania Public Utility Commission
3 years Actual and 2 Years Projected Ended September 30, 2023
($ in Thousands)

Outside Contractor Expense by Account

ACCOUNT DESCRIPTION	2019 Actual	2020 Actual	2021 Actual	2022 Budget	2023 Budget
PLANT CONTRACTOR LABOR: ENGINEERING	89	144	78	153	158
PLANT CONTRACTOR LABOR: ENVIRONMENTAL	106	141	62	100	103
PLANT CONTRACTOR LABOR: FABRICATION/WELDING	95	150	172	113	116
PLANT CONTRACTOR LABOR: LABORATORY ANALYSIS	13	6	4	42	42
PLANT CONTRACTOR LABOR: OTHER	5,321	4,957	5,486	7,259	7,830
PLANT CONTRACTOR LABOR: PIPELINE	14,908	11,802	9,870	9,942	10,979
PLANT CONTRACTOR LABOR: RESTORATION	1,845	1,341	1,987	1,331	1,379
PLANT CONTRACTOR LABOR: SNOW REMOVAL	108	1	4	3	3
PLANT CONTRACTOR LABOR: TRAFFIC CONTROL	323	1,210	1,166	1,073	1,114
PLANT CONTRACTOR LABOR: TREE TRIMMING	65	91	44	-	-
TOTAL	**22,872**	**19,843**	**18,873**	**20,017**	**21,723**

Outside Contractor Expense by Operating Expense on Schedule D-1

OPERATING EXPENSE TYPE ON SCHEDULE D-1	2019 Actual	2020 Actual	2021 Actual	2022 Budget	2023 Budget
ADMINISTRATIVE AND GENERAL EXPENSES	416	1,420	1,318	1,343	1,383
CUSTOMER ACCOUNT OPERATIONS EXPENSES	65	62	21	52	54
DISTRIBUTION	22,391	18,360	17,534	18,621	20,286
TOTAL	**22,872**	**19,843**	**18,873**	**20,017**	**21,723**

UGI Gas Exhibit TJA-2R

UGI Utilities, Inc - Gas Division
Outside Contractor Expense
($ in Thousands)

	(a) 2023 Budget	Contractor Increase (Weighted Avg.)		2023 Updated	2023 $ Increase
PLANT CONTRACTOR LABOR: PIPELINE	$ 10,979	13.10%		$ 12,416	$ 1,438
PLANT CONTRACTOR LABOR: RESTORATION	1,379	25.90%		1,736	357
PLANT CONTRACTOR LABOR: TRAFFIC CONTROL	1,114	27.23%		1,417	303
PLANT CONTRACTOR LABOR: OTHER	8,252	7.20%	(b)	8,846	594
TOTAL	**$ 21,723**	**12.39%**		**$ 24,416**	**$ 2,692**

(a) 2023 budget represents the Company's original FPFTY expense claim for contractor labor.
(b) Other contractor labor was increased based on the CPI percentage.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 10-R

Rebuttal Testimony of
Constance E. Heppenstall

Topics Addressed:	**Cost of Service Study** **Customer Charges**

Date: May 17, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Constance E. Heppenstall. My business address is 1010 Adams Avenue, Audubon, Pennsylvania.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 10, on January 28, 2022.

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to certain portions of the following direct testimony: Office of Consumer Advocate ("OCA") Statement No. 3, the direct testimony of Jerome D. Mierzwa, and Office of Small Business Advocate ("OSBA") Statement No. 1, the direct testimony of Robert D. Knecht. I also reference the direct testimonies of Commission on Economic Opportunity ("CEO") Witness Eugene M. Brady (CEO Statement No, 1), Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Witness Harry S. Geller (CAUSE-PA St. No. 1) and OCA Witness Roger D. Colton (OCA St. No. 4) regarding the Company's proposed increase to the customer charge.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. UGI Gas Exhibit D-R, Cost of Service Allocation Study as of September 30, 2023, and UGI Gas Exhibit CEH-1R are attached.

Q. What changes were made to the cost of service study provided in UGI Gas Exhibit D-R?

A. The study was updated to include a revised split of costs in FERC Account 874. It was explained in response to discovery request OCA-I-24 that the costs in FERC Account 874 were incorrectly allocated 51.93% to mains and 48.07% to services. The correct allocation is 55.08% to mains and 44.92% to services. In addition, the study was updated to reflect the revised allocation of costs identified as related to manufactured gas plant remediation found in Accounts 923 and 930 based on Factor 1, as described in my rebuttal of Mr. Mierzwa's direct testimony below. The study also breaks out reconnection charges from Other Miscellaneous Revenues and allocates them pursuant to a new Factor 22, which is based on the reconnection fee revenues by class for the twelve months ended January 31, 2022, and allocates forfeited discounts pursuant to a new Factor 23, which is based on actual forfeited discounts by class for the twelve months ended January 31, 2022. Finally, the study incorporates Mr. Knecht's revised design day demand for Rate R/RT and N/NT customers. (OSBA St. No. 1 at 12-13.)

II. <u>COST OF SERVICE STUDY</u>

<u>OCA Statement No. 3 – Jerome D. Mierzwa</u>

Q. Beginning on page 10 of OCA Statement No. 3, Mr. Mierzwa states that the Average and Excess ("A&E") method you used in your cost of service allocation study (UGI Gas Exhibit D) does not produce a reasonable allocation of mains costs on the UGI system. Why did you use the A&E method?

A. As discussed below, the A&E method I utilized has been generally accepted by the

Pennsylvania Public Utility Commission ("Commission") for a number of years. The Commission's most recent decision and guidance in a fully litigated gas rate case approved a methodology using this A&E method in the PECO Energy Company ("PECO") Gas Rate Case at Docket No. R-2020-3018929 ("PECO Gas Rate Case Order").[1] In addition, the cost of service study utilizing the A&E method, submitted by our firm in 2006 for the PPL Gas Utilities Corporation ("PPL Gas") (subsequently UGI Central Penn Gas, Inc. and now part of UGI Gas) base rate case at Docket No. R-00061398, was also approved by the Commission (referred to herein as the "PPL Gas Case").[2] In the PPL Gas Case cost allocation study, PPL Gas weighted the average use 40% and excess capacity 60%, based on the system load factor in a manner similar to the A&E method used in my Cost of Service Study ("COSS") for UGI Gas in this case.

Q. What is the basis for your decision to use the A&E method over the Peak and Average ("P&A") method utilized by OCA?

A. The P&A method places too much weight on average use. In fact, the P&A method double counts the average demand because it uses average demand twice, *i.e.*, once in the calculation of average demand and again in the calculation of peak demand. This is evident because peak demand figures include the entire demand, including average use. Mr. Mierzwa's P&A allocator, therefore, double-counts average use and places little emphasis on the peak demands of customers that UGI Gas must design its system to meet. The A&E method used in my study properly weights the portion of the system on average demands

[1] *Pa. Pub. Util. Comm'n v. PECO Energy Co. – Gas Division*, Docket No. R-2020-3018929 (June 22, 2021); *see also Pa. Pub. Util. Comm'n v. Phila. Gas Works*, Docket No. R-00061931 (Sept. 28, 2007).

[2] *Pa. Pub. Util. Comm'n v. PPL Gas Util. Corp.*, Docket No. R-00061398 (Feb. 8, 2007).

and the portion of the system on the excess capacity of peak demands.

Q. Has the P&A method been approved in other cases before the Commission?

A. Yes, it is my understanding that the Commission in the past accepted the P&A method. However, more recently, it has chosen to use the A&E methodology where one party has proposed to use the P&A methodology (as is the case in this proceeding). In addition, in the PECO Gas Rate Case Order discussed above, the Commission affirmed the use of the A&E methodology in the following statement:

> Moreover, we are also persuaded by PECO's argument regarding the implicit double counting of average demand in the P&A methodology. Again, the A&E methodology allocates mains costs based, in part, on average demand and, in part, on the portion of peak demand that exceeds average demand. Alternatively, mains costs are allocated under the P&A methodology based, in part, on average demand and, in part, on the total peak demand. Consequently, average demand is included in the average demand component and in the peak demand component, which includes average demand. Accordingly, due to residential customers having temperature-sensitive demand and corresponding low-load factors, double-counting average demand understates the residential cost of service while overstating the cost of service of more efficient gas users. PECO R. Exc. at 21-22; PECO M.B. at 101. Based on the above, we find that the Company's proposed A&E methodology is more reflective of an accurate representation of PECO's mains distribution system.

PECO Gas Rate Case Order at 229-30.

Q. Please illustrate how the P&A method is flawed.

A. Take, for example, a system that has a peak day demand of 1,000 units and an average day demand of 400 units. The peak and average method will give equal weight to the average demand of 400 units per day and to the peak day demand of 1,000 units. But, the 400 average day units are also included in the 1,000 peak day units, so the average is counted twice. In the A&E method, however, the 400 average day units and the amount <u>over the</u>

average of 600 units (excess capacity) are weighted based on the system load factor so that the average day demand is not double counted. The P&A method erroneously uses 1,400 units (400 average and 1,000 peak day units) as a basis for allocation, rather than the actual 1,000 peak day units used in the A&E method. Stated another way, my A&E method would allocate 42.1% percent of costs to average demand and 57.9% to peak demand. By contrast, Mr. Mierzwa's P&A method would allocate 57% to average demand ((400 + 400) / 1400) and 43% to peak demand. It makes no sense, in my view, to allocate 57% of costs based on average demand when the same average demand represents only 42.1% of the overall capacity of the mains needed on a peak day, yet this is precisely the result achieved under Mr. Mierzwa's analysis.

Q. Your cost of service study, presented in UGI Gas Exhibit D, allocates the cost of mains based on the A&E method after assigning the cost of mains directly attributable to the XD-Firm and XD-I customers. Did Mr. Mierzwa object to the direct assignment approach?

A. No. Although he did not mention or comment on the Company's approach to directly assign the cost of mains to the XD-F and XD-I customers, his workpapers submitted in Excel format clearly show that he uses the same costs directly assigned to the XD customers as presented in the Company's study.

Q. How did you allocate mains to the other classes?

A. I used the A&E method with no excess capacity allocated to the interruptible service class.

Q. Why did you conclude that no excess capacity allocated to interruptible customers was appropriate?

A. As explained in my direct testimony, interruptible service customers can be interrupted during periods of peak demand, and UGI Gas's mains are designed to only meet the peak day requirements of firm service customers. Thus, the excess amount is zero.

Q. Did Mr. Mierzwa acknowledge that it is appropriate to allocate mains to the interruptible class as you did in Exhibit D?

A. No, to the contrary, he disagrees with my approach for the interruptible customers. In his P&A study, Mr. Mierzwa uses: (1) the average day requirement for the peak day portion of his allocation factor; and (2) the average usage in his average day component. This further demonstrates the double counting of the average day usage. By using average day in his peak day component, however, he agrees that there is no extra capacity assigned to the Rate IS class.

My A&E study accounts for the average day usage once by using only the average day requirement for the IS class with no extra capacity.

Q. Mr. Mierzwa claims that your A&E method, which weights the average and excess demands based on the system peak day, equates to using a peak allocator. Do you agree?

A. No, I do not. Mr. Mierzwa's assertion that my A&E allocation is identical to a pure peak allocator is simply wrong. Table 3 on page 13 of his testimony clearly demonstrates that my A&E method does not produce the same result as a pure peak allocation. For example, the difference between a pure peak allocator (of 0.5022) and my A&E factor (of 0.4685) is 3.37% less for Rate R under my A&E method versus a pure peak allocator. (OCA St. No. 3 at 13.) When allocating over $1.8 billion in rate base for mains, a 3% change in allocation will result in a $54,000,000 difference in the allocation of rate base, which is significant.

My A&E allocation is weighted based on a firm 2.4 peak day factor, which results in a weighting of 42.1% for average day usage and 57.9% for extra capacity. The approximate 40/60 weighting is the same weighting used in the Company's A&E cost of service study from the 2006 PPL Gas case, which was accepted by the Commission. Mr. Mierzwa's rejection of my A&E cost allocation, because he believes that it is a pure peak allocation, is unfounded.

Q. Did Mr. Mierzwa make other allocation revisions to your study?

A. Yes. He proposed revisions to the allocation of manufactured gas plant ("MGP") remediation expenses, forfeited discounts, and other miscellaneous revenues. (OCA St. No. 3 at 27.)

Q. Do you agree with Mr. Mierzwa's revision to the allocation of expenses associated with MGP remediation.

A. No, I do not. The remediation expenses relate to MGPs, which have been long retired and no longer produce gas supply. However, if these MGPs were still in operation, the gas produced, and the associated costs would be included in the Company's Purchased Gas Cost ("PGC") calculation related to core market residential and small firm service. This is because, historically, the MGPs were overwhelmingly used to provide gas supply to residential and small commercial customers, rather than industrial customers. Therefore, it is appropriate to allocate remediation costs associated with the past provision of service to PGC customers to PGC customers. In fact, during discovery in response to OCA-I-31, additional costs related to MGPs were identified. In Exhibit D-R, I broke these costs out separately and allocated them based on Factor 1.

Q. Do you agree with Mr. Mierzwa's revision to forfeited discounts?

A. Yes. During discovery, actual forfeited discounts by rate class for a recent twelve-month period was provided in discovery in response to OCA-I-18. Based on this information, I calculated a new Factor 23, which allocates the FPFTY forfeited discounts by class based on the information in response to OCA-I-18. This revision is reflected in UGI Gas Exhibit D-R.

Q. Do you agree with Mr. Mierzwa's revision to the allocation of reconnection fees included in miscellaneous revenues?

A. Yes. During discovery, the Company provided actual reconnection fee revenues by rate class for a recent twelve-month period in the response to interrogatory OCA-I-42.[3] A copy of that discovery response is attached to my testimony as UGI Gas Exhibit CEH-1R. As such, I calculated a new Factor 22, which allocates the FPFTY reconnection fee based on the information set forth in UGI Gas Exhibit CEH-1R. This revision is also reflected in

[3] The amount of reconnection fees was erroneously included in Other Miscellaneous revenues in the originally-filed cost of service study and allocated pursuant to Factor 16. Specifically, the line item for Reconnection Fees (to be allocated pursuant to Factor 6C) was $0.0 in the original cost of service study. The amount of reconnection fees in the revised cost of service study are the same as filed, but broken out separately. Reconnections fee costs are being allocated based on the information provided in discovery in Attachment OCA-I-42.

UGI Gas Exhibit D-R.

Q. What do you conclude with respect to Mr. Mierzwa's cost allocation study?

A. Mr. Mierzwa's allocation of mains investment using the P&A method, which double counts the average demand, is unreasonable and inconsistent with the Commission's last fully litigated natural gas base rate case. The Commission should use the Company's studies as a guide for revenue distribution in this case. As discussed above, his other allocation factors for the MGP costs and the IS rate class are also inappropriate.

<u>OSBA Statement No. 1 – Robert Knecht</u>

Q. Does Mr. Knecht generally agree with the Company's cost of service study?

A. Yes, Mr. Knecht acknowledges that the cost of service methodology used in the filing aligns with the methodology used in the Company's prior rate cases. However, he does recommend a change in the calculation of design day demands for the Rate R/RT and Rate N/NT classes that are used in the study. After reviewing Mr. Knecht's recommendation, the Company finds it to be acceptable. Exhibit D-R reflects this change, which is detailed below.

	As Filed Peak Day MCF	Revised Peak Day MCF	Difference
Residential	649,604	691,772	42,168
N	431,709	389,541	-42,168
DS	96,848	96,848	0
LFD	115,419	115,419	0
XD - Firm	821,122	821,122	0

III. CUSTOMER CHARGES

Q. Please discuss the parties' positions related to the Company's increases to the customer charges.

A. OSBA witness Knecht does not object to a $30.00 per month customer charge for Rate N/NT as the rate is cost based. However, OCA witness Colton, OCA witness Mierzwa, CEO witness Brady, and CAUSE-PA witness Geller all oppose the increase to the customer charge for Rate R/RT customers.

Q. Do you recommend that the Company increase its customer charges under proposed rates?

A. Yes. Schedule G of the cost of service study calculates the customer costs per bill by service classification. The schedule in Exhibit D-R shows that the Company can justify customer charges for Rate R/RT customers of $27.79 per month and $46.26 for Rate N/NT customers, using only direct customer costs. The level would be higher if all customer costs were included. These justifiable levels are higher rates than the customer charges proposed by the Company of $19.95 for Rate R/RT and $30.00 for Rate N/NT. As none of the parties contested the calculation of customer costs per bill, which is based on recovering direct customer costs through the customer charge, the proposed increases to the customer charges should be approved.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit D-R

UGI Gas Exhibit D-R
Witness: C. E. Heppenstall

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

COST OF SERVICE ALLOCATION STUDY

AS OF SEPTEMBER 30, 2023

REBUTTAL

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
Camp Hill, Pennsylvania

UGI UTILITIES, INC. - GAS DIVISION

COMPARISON OF COST OF SERVICE WITH REVENUES UNDER PRESENT AND PROPOSED RATES
BY SERVICE CLASSIFICATION FOR THE TWELVE MONTHS ENDED SEPTEMBER 30, 2023
WITHOUT GAS COSTS

	Pro Forma Cost of Service		Pro Forma Margin Revenues, Under Present Rates		Pro Forma Margin Revenues, Under Proposed Rates		Revenue Increase	
Service Classification	Amount	Percent	Amount	Percent	Amount	Percent	Amount	Percent Increase
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Rate R	$ 480,764,419	65.1%	$ 377,368,713	57.5%	$ 445,483,863	60.3%	$ 68,115,150	18.1%
Rate N	139,578,438	18.9%	138,825,398	21.2%	153,278,225	20.8%	14,452,827	10.4%
Rate DS	32,178,026	4.4%	33,778,394	5.2%	34,432,339	4.7%	653,946	1.9%
Rate LFD	40,587,439	5.5%	44,861,623	6.8%	46,392,850	6.3%	1,531,227	3.4%
Rate XD Firm	27,384,764	3.7%	36,697,802	5.6%	35,735,967	4.8%	(961,834)	-2.6%
Interruptible	17,521,765	2.4%	24,012,357	3.7%	22,963,170	3.1%	(1,049,187)	-4.4%
Total	$ 738,014,851	100.0%	$ 655,544,286	100.0%	$ 738,286,415	100.0%	$ 82,742,129	12.6%
Other Operating Revenues	10,287,000		10,287,000		10,287,000		0	
Total	$748,301,851		$665,831,286		$748,573,415		$82,742,129	12.4%

UGI UTILITIES, INC. - GAS DIVISION

DEVELOPMENT OF RATE OF RETURN BY SERVICE CLASSIFICATION
UNDER PROPOSED RATES

Item	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD-Firm	Interruptible
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1. Revenues From Tariff Sales and Transportation	$ 655,544,286	$ 377,368,713	$ 138,825,398	$ 33,778,394	$ 44,861,623	$ 36,697,802	$ 24,012,357
2. Other Revenues	10,286,731	6,342,743	2,569,602	419,105	483,354	285,142	186,785
3. Total Operating Revenues	665,831,017	383,711,456	141,395,000	34,197,499	45,344,977	36,982,944	24,199,142
4. Less: Operating Expenses	431,316,623	293,748,449	73,091,991	18,029,890	21,121,357	16,403,468	8,921,468
5. Return and Income Taxes	234,514,394	89,963,007	68,303,009	16,167,609	24,223,620	20,579,475	15,277,674
6. Less: Interest Expense [1]	56,726,000	34,478,063	12,405,976	2,632,086	3,590,756	2,036,463	1,582,655
7. Taxable Income	177,788,394	55,484,944	55,897,033	13,535,523	20,632,864	18,543,012	13,695,019
8. Less: Income Taxes	39,835,701	12,432,722	12,524,344	3,031,497	4,624,925	4,154,864	3,067,349
9. Net Return (Ln 5 - Ln 8)	194,678,693	77,530,285	55,778,665	13,136,112	19,598,695	16,424,611	12,210,325
10. Original Cost Measure of Value (Factor 15.)	3,169,108,705	1,926,427,388	693,071,652	146,957,966	200,476,193	113,620,213	88,555,293
11. Rate of Return, Percent	6.14%	4.02%	8.05%	8.94%	9.78%	14.46%	13.79%
12. Relative Rate of Return	1.00	0.66	1.31	1.46	1.59	2.35	2.24

UGI UTILITIES, INC. - GAS DIVISION

DEVELOPMENT OF RATE OF RETURN BY SERVICE CLASSIFICATION
UNDER PROPOSED RATES

Item (1)	Cost of Service (2)	Rate R (3)	Rate N (4)	Rate DS (5)	Rate LFD (6)	Rate XD-Firm (7)	Interruptible (8)
1. Revenues From Tariff Sales and Transportation	$ 738,286,415	$ 445,483,863	$ 153,278,225	$ 34,432,339	$ 46,392,850	$ 35,735,967	$ 22,963,170
2. Other Revenues	10,287,001	6,341,750	2,572,670	418,171	483,684	283,911	186,815
3. Total Operating Revenues	748,573,416	451,825,613	155,850,895	34,850,510	46,876,534	36,019,878	23,149,985
4. Less: Operating Expenses	432,700,203	295,220,368	73,129,028	17,983,841	21,093,538	16,370,135	8,903,293
5. Return and Income Taxes	315,873,213	156,605,245	82,721,867	16,866,670	25,782,996	19,649,743	14,246,692
6. Less: Interest Expense	56,726,000	34,500,753	12,400,304	2,626,414	3,585,083	2,030,791	1,582,655
7. Taxable Income	259,147,213	122,104,492	70,321,563	14,240,256	22,197,913	17,618,952	12,664,037
8. Less: Income Taxes	63,347,000	29,836,437	17,192,376	3,484,085	5,428,838	4,307,596	3,097,668
9. Net Return (Ln 5 - Ln 8)	252,526,213	126,768,808	65,529,491	13,382,585	20,354,158	15,342,147	11,149,024
10. Original Cost Measure of Value (Factor 15.)	3,169,022,984	1,927,057,142	692,833,162	146,798,970	200,356,950	113,500,965	88,475,795
11. Rate of Return, Percent	7.97%	6.58%	9.46%	9.12%	10.16%	13.52%	12.60%
12. Relative Rate of Return	1.00	0.83	1.19	1.14	1.27	1.70	1.58

UGI UTILITIES, INC. - GAS DIVISION

SUMMARY OF COST OF SERVICE BY SERVICE CLASSIFICATION

Cost Function	Cost of Service (Schedule E)	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Volumetric Costs							
Rate R	$ 233,773,379	$ 233,773,379					
Rate N	94,604,876		$ 94,604,876				
Rate DS	23,993,482			$ 23,993,482			
Rate LFD	34,701,242				$ 34,701,242		
Rate XD Firm	26,231,225					$ 26,231,225	
Rate IS/IL	14,563,029						$ 14,563,029
Total Volumetric Costs	427,867,232	233,773,379	94,604,876	23,993,482	34,701,242	26,231,225	14,563,029
Customer Costs							
Rate R	$ 246,991,041	$ 246,991,041					
Rate N	44,973,562		$ 44,973,562				
Rate DS	8,184,544			$ 8,184,544			
Rate LFD	5,886,197				$ 5,886,197		
Rate XD Firm	1,153,539					$ 1,153,539	
Rate IS/IL	2,958,736						$ 2,958,736
Total Customer Costs	310,147,618	246,991,041	44,973,562	8,184,544	5,886,197	1,153,539	2,958,736
Total Excluding Gas Costs	$ 738,014,851	$ 480,764,419	$ 139,578,438	$ 32,178,026	$ 40,587,439	$ 27,384,764	$ 17,521,765

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

		Factor	Cost of	Volumetric Costs						Customer Costs					
	Account	Ref.	Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	OPERATION AND MAINTENANCE EXPENSES														
	NATURAL GAS PRODUCTION EXPENSES														
	Manufactured Gas Production Expenses														
710	Operation Supervision and Engineering	1	0	-	-	-	-	-	-	-	-	-	-	-	-
717	Total Production Labor and Expenses	1	0	-	-	-	-	-	-	-	-	-	-	-	-
725-736	Total Gas Fuels Expenses	1	14,000	10,046	3,954	-	-	-	-	-	-	-	-	-	-
740-742	Total Gas Raw Materials Expenses	1	983,333	705,640	277,693	-	-	-	-	-	-	-	-	-	-
	Total Operation		997,333	715,686	281,647	-	-	-	-	-	-	-	-	-	-
	Production and Gathering														
750 - 760	Total Production & Gathering Operation Exps.	1	-	-	-	-	-	-	-	-	-	-	-	-	-
761 - 769	Total Production & Gathering Maintenance Exps.	1	-	-	-	-	-	-	-	-	-	-	-	-	-
770 - 783	Total Products Extraction Operation Expenses	1	-	-	-	-	-	-	-	-	-	-	-	-	-
784 - 791	Total Products Extraction Maintenance Exps.	1	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Production Expenses		-	-	-	-	-	-	-	-	-	-	-	-	-
	Other Gas Supply Expenses														
800 - 803	Natural Gas Transmission Line Purchases	1	-	-	-	-	-	-	-	-	-	-	-	-	-
804	Natural Gas City Gate Purchases	1	-	-	-	-	-	-	-	-	-	-	-	-	-
805.1	Purchases Gas Cost Adjustments	1	-	-	-	-	-	-	-	-	-	-	-	-	-
805	Other Gas Purchases	1	-	-	-	-	-	-	-	-	-	-	-	-	-
808.1	Gas Withdrawn from Storage-Debit	1	-	-	-	-	-	-	-	-	-	-	-	-	-
808.2	Gas Delivered to Storage-Credit	1	-	-	-	-	-	-	-	-	-	-	-	-	-
812	Gas Used for Operations	1	-	-	-	-	-	-	-	-	-	-	-	-	-
813	Other Gas Supply Expenses	1	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Other Gas Supply Expenses		-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Natural Gas Production Expenses		**997,333**	**715,686**	**281,647**	-	-	-	-	-	-	-	-	-	-
	OTHER STORAGE EXPENSE														
840	Operating Supervision and Engineering	1A	-	-	-	-	-	-	-	-	-	-	-	-	-
841	Operation Labor and Expenses	4	-	-	-	-	-	-	-	-	-	-	-	-	-
842 - 842.3	Other Operations Expense	4	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Natural Gas Storage Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
	TRANSMISSION EXPENSE														
850 - 860	Total Transmission Operation Expenses	4	-	-	-	-	-	-	-	-	-	-	-	-	-
861 - 867	Total Transmission Maintenance Expenses	4	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Transmission Expense		-	-	-	-	-	-	-	-	-	-	-	-	-
	DISTRIBUTION EXPENSES														
	Operation														
870	Supervision And Engineering	10	5,304,635	1,001,515	568,657	146,408	206,350	328,357	88,587	2,208,850	627,008	58,351	42,437	7,426	20,688
871	Distribution Load Dispatching	4A	2,030	646	364	91	109	780	41	-	-	-	-	-	-
872	Compressor Station Labor and Expenses		-												
873	Compressor Station Fuel and Power	2	-	-	-	-	-	-	-	-	-	-	-	-	-
874	Mains And Services Expenses														
	Mains - Small	4	4,364,255	2,153,760	1,225,483	317,718	463,047	-	204,247	-	-	-	-	-	-
	Mains - Large	17	8,023,853	3,625,979	2,062,130	534,389	779,116	678,818	343,421	-	-	-	-	-	-
	Services	6C	15,189,242	-	-	-	-	-	-	13,241,981	1,824,228	60,757	37,973	4,557	19,746
875	M & R Station Expenses -General	4A	4,226,551	1,345,311	757,398	188,504	226,966	1,623,841	84,531	-	-	-	-	-	-
876	M & R Station Expenses - Industrial	6B	12,194	-	-	-	-	-	-	-	-	5,434	4,065	734	1,961
877	M & R Station Expenses - City Gate Station	4A	115,674	36,819	20,729	5,159	6,212	44,442	2,313	-	-	-	-	-	-
878	Meter and House Regulator Expenses	6	3,245,151	-	-	-	-	-	-	1,381,785	1,437,926	189,517	141,813	25,637	68,473
879	Customer Installations Expenses	6	2,759,655	-	-	-	-	-	-	1,175,061	1,222,803	161,164	120,597	21,801	58,229
880	Other Expenses	10	1,297,033	244,880	139,042	35,798	50,455	80,286	21,660	540,085	153,309	14,267	10,376	1,816	5,058
881	Rents	10	3,117,000	588,490	334,142	86,029	121,251	192,942	52,054	1,297,919	368,429	34,287	24,936	4,364	12,156
881	Rents - Directly Assigned to XD	DA	565,000					565,000							
	Total Operation		48,222,273	8,997,400	5,107,945	1,314,096	1,853,506	3,514,466	796,854	19,845,681	5,633,703	523,777	382,197	66,335	186,311

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

				Volumetric Costs						Customer Costs					
	Account	Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Maintenance														
885	Supervision - Engineering and Labor	11	516,307	194,699	110,645	28,603	41,201	38,052	18,019	18,277	2,530	28,655	21,427	3,872	10,326
886	Structures & Improvements	18	-	-	-	-	-	-	-	-	-	-	-	-	-
887	Mains - Small	4	9,960,460	4,915,487	2,796,897	725,121	1,056,805	-	466,150	-	-	-	-	-	-
	Mains - Large	17	18,312,694	8,275,506	4,706,362	1,219,625	1,778,163	1,549,254	783,783	-	-	-	-	-	-
888	Maintenance of Compressor Station Equipment	4	262,000	129,297	73,570	19,074	27,798	-	12,262	-	-	-	-	-	-
889	M & R Equip - General	4A	3,156,282	1,004,645	565,606	140,770	169,492	1,212,644	63,126	-	-	-	-	-	-
890	M & R Equip - Industrial	6B	4,732,873	-	-	-	-	-	-	-	-	2,108,968	1,577,940	284,919	761,046
891	M & R Equip - City Gate	4A	121,179	38,571	21,715	5,405	6,507	46,557	2,424	-	-	-	-	-	-
892	Services	6C	1,547,015	-	-	-	-	-	-	1,348,688	185,797	6,188	3,868	464	2,011
893	Meters & House Regulators	6	-	-	-	-	-	-	-	-	-	-	-	-	-
894	Other Expenses	11	555,780	209,585	119,104	30,790	44,351	40,961	19,397	19,675	2,723	30,846	23,065	4,168	11,116
895	Construction and Maintenance	11	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Maintenance		39,164,590	14,767,790	8,393,899	2,169,388	3,124,317	2,887,468	1,365,161	1,386,640	191,050	2,174,657	1,626,300	293,423	784,499
	Total Distribution Expenses		**87,386,863**	**23,765,190**	**13,501,844**	**3,483,484**	**4,977,823**	**6,401,934**	**2,162,015**	**21,232,321**	**5,824,753**	**2,698,434**	**2,008,497**	**359,758**	**970,810**
	CUSTOMER ACCOUNTING EXPENSES														
	Operation														
901	Supervision	7	832,203	-	-	-	-	-	-	744,572	84,718	1,664	749	83	416
902	Meter Reading Expenses	7	2,208,095	-	-	-	-	-	-	1,975,583	224,784	4,416	1,987	221	1,104
903	Customer Records & Coll Expenses	7	19,474,018	-	-	-	-	-	-	17,423,404	1,982,455	38,948	17,527	1,947	9,737
903.1	Universal Service Program	DA	17,537,000	17,537,000											
904	Uncollectible Accounts	19	17,957,980	6,465,085	493,184					10,147,842	668,697	14,366	30,529	100,565	37,712
905	Miscellaneous Cust Accts Expenses	7	2,318,249	-	-	-	-	-	-	2,074,137	235,998	4,636	2,086	232	1,159
	Total Customer Accounting Expenses		**60,327,545**	**24,002,085**	**493,184**	**-**	**-**	**-**	**-**	**32,365,538**	**3,196,652**	**64,030**	**52,878**	**103,048**	**50,128**
	CUSTOMER SERVICE AND INFORMATION EXPENSES														
	Operation														
907	Supervision	7	174,406	-	-	-	-	-	-	156,041	17,755	349	157	17	87
908	Customer Assistance Expenses	9	714,061	-	-	-	-	-	-	714,061	-	-	-	-	-
909	Informational and Instructional Advertising	7	-	-	-	-	-	-	-	-	-	-	-	-	-
910	Miscellaneous Customer Service & Informational Exp.	7	62,958	-	-	-	-	-	-	56,329	6,409	126	57	6	31
910.1	Energy Efficiency and Conservation Programs	DA	12,717,939	10,801,850	634,636	534,450	747,003								
	Total Customer Service & Info Expenses		**13,669,364**	**10,801,850**	**634,636**	**534,450**	**747,003**	**-**	**-**	**926,431**	**24,164**	**475**	**214**	**23**	**118**
	SALES EXPENSES														
	Operation														
911	Supervision	8	431,364	-	-	-	-	-	-	387,279	44,085	-	-	-	-
912	Demonstrating and Selling Expenses	8	(677,610)	-	-	-	-	-	-	(608,358)	(69,252)	-	-	-	-
908/912	Service Representatives	7A	283,600	-	-	-	-	-	-	-	-	163,609	70,758	6,580	42,653
913	Advertising Expenses	8	1,637,284	-	-	-	-	-	-	1,469,954	167,330	-	-	-	-
916	Miscellaneous	8	258,000	-	-	-	-	-	-	231,632	26,368	-	-	-	-
	Total Sales Expenses		**1,932,639**	**-**	**-**	**-**	**-**	**-**	**-**	**1,480,507**	**168,531**	**163,609**	**70,758**	**6,580**	**42,653**
	ADMINISTRATIVE AND GENERAL EXPENSES														
	Operation														
920	Administrative & General Salaries	12	36,437,774	13,066,586	3,264,825	896,369	1,278,966	1,428,361	480,979	12,494,513	2,055,090	652,236	477,335	105,670	236,846
921	Office Supplies and Expenses	12	21,222,000	7,610,209	1,901,491	522,061	744,892	831,902	280,130	7,277,024	1,196,921	379,874	278,008	61,544	137,943
922	Administrative Expenses Transferred-Credit														
923	Outside Services Employed - Other	12	19,559,015	7,013,863	1,752,488	481,152	686,521	766,713	258,179	6,706,786	1,103,128	350,106	256,223	56,721	127,134
923	Outside Services Employed - Other - MFG	1	6,052,000	4,342,915	1,709,085	-	-	-	-	-	-	-	-	-	-
924	Property Damage Insurance	12	-	-	-	-	-	-	-	-	-	-	-	-	-
925	Injuries and Damages	12	10,371,987	3,719,395	929,330	255,151	364,057	406,582	136,910	3,556,554	584,980	185,659	135,873	30,079	67,418
926	Employee Pensions and Benefits	13	22,410,000	4,988,466	2,144,637	562,491	802,278	979,317	336,150	9,302,391	1,884,681	629,721	466,128	87,399	226,341
927	Franchise Requirements														
928	Regulatory Commission Expenses	16	1,193,000	373,528	150,915	38,534	55,713	42,232	23,383	402,876	75,398	13,600	9,902	2,028	4,891
929	Duplicate Charges-Credit														
930	Miscellaneous General Expenses	12	292,079	104,740	26,170	7,185	10,252	11,449	3,855	100,154	16,473	5,228	3,826	847	1,899
930	Miscellaneous Company Charges	12	4,610,970	1,653,494	413,143	113,430	161,845	180,750	60,865	1,581,102	260,059	82,536	60,404	13,372	29,971
930	Miscellaneous Company Charges - MGP	1	2,327,000	1,669,855	657,145	-	-	-	-	-	-	-	-	-	-
931	Other	12	38,000	13,627	3,405	935	1,334	1,490	502	13,030	2,143	680	498	110	247
	Total Operation		124,513,825	44,556,678	12,952,634	2,877,308	4,105,858	4,648,796	1,580,953	41,434,430	7,178,873	2,299,640	1,688,197	357,770	832,690

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

				Volumetric Costs						Customer Costs					
	Account	Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Maintenance														
932	Maintenance of General Plant	12	4,411,000	1,581,785	395,226	108,511	154,826	172,911	58,225	1,512,532	248,780	78,957	57,784	12,792	28,672
935	Maintenance of General Plant	12	267,000	95,746	23,923	6,568	9,372	10,466	3,524	91,554	15,059	4,779	3,498	774	1,736
	Total Maintenance		4,678,000	1,677,531	419,149	115,079	164,198	183,377	61,749	1,604,086	263,839	83,736	61,282	13,566	30,408
	Total Administrative & General Expenses		**129,191,825**	**46,234,209**	**13,371,783**	**2,992,387**	**4,270,056**	**4,832,173**	**1,642,702**	**43,038,516**	**7,442,712**	**2,383,376**	**1,749,479**	**371,336**	**863,098**
	Total Operation and Maintenance Expenses		**293,505,569**	**105,519,021**	**28,283,094**	**7,010,321**	**9,994,882**	**11,234,107**	**3,804,717**	**99,043,313**	**16,656,812**	**5,309,924**	**3,881,826**	**840,745**	**1,926,807**
DEPRECIATION AND AMORTIZATION EXPENSE															
PRODUCTION PLANT															
305	Manufactured Gas Plant Site Remdiation	2	(23,039)	(3,523)	(2,106)	(650)	(1,599)	(14,116)	(1,046)	-	-	-	-	-	-
325.2	Production Leaseholds	2	33	5	3	1	2	20	1	-	-	-	-	-	-
325.4	Rights-Of-Way	2	18	3	2	1	1	11	1	-	-	-	-	-	-
328	Field Measuring and Regulating Station Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Other Structures	2	-	-	-	-	-	-	-	-	-	-	-	-	-
330	Producing Gas Wells - Well Construction	2	-	-	-	-	-	-	-	-	-	-	-	-	-
331	Producint Gas Wells - Well Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
332	Field Lines	2	948	145	87	27	66	581	43	-	-	-	-	-	-
334	Field Measuring and Regulating Station Equipment	2	383	59	35	11	27	235	17	-	-	-	-	-	-
335	Drilling and Cleaning Equipment	2	16	2	1	-	1	10	1	-	-	-	-	-	-
337	Other Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Production Plant		**(21,641)**	**(3,309)**	**(1,978)**	**(610)**	**(1,502)**	**(13,259)**	**(983)**	**-**	**-**	**-**	**-**	**-**	**-**
STORAGE PLANT															
352.01	**Well Construction**	**2**	-	-	-	-	-	-	-	-	-	-	-	-	-
TRANSMISSION PLANT															
365.2	Rights-Of-Way	4	11,469	5,660	3,220	835	1,217	-	537	-	-	-	-	-	-
366	Structures and Improvements	4	1,122	554	315	82	119	-	53	-	-	-	-	-	-
367	Mains	4	452,433	223,276	127,043	32,937	48,003	-	21,174	-	-	-	-	-	-
369	Measuring and Regulating Staion Equipment	4	90,744	44,782	25,481	6,606	9,628	-	4,247	-	-	-	-	-	-
370	Communication Equipment	4	97,784	48,256	27,458	7,119	10,375	-	4,576	-	-	-	-	-	-
371	Other Equipment	4	1,074	530	302	78	114	-	50	-	-	-	-	-	-
371.1	Testing Equipment	4	4,914	2,425	1,380	358	521	-	230	-	-	-	-	-	-
	Total Transmission Plant		**659,540**	**325,483**	**185,199**	**48,015**	**69,977**	**-**	**30,867**	**-**	**-**	**-**	**-**	**-**	**-**
DISTRIBUTION PLANT															
305	Manufactured Gas Plant Site Remediation	1	-	-	-	-	-	-	-	-	-	-	-	-	-
374.2	Rights of Way	18	45,770	21,311	12,124	3,144	4,582	2,586	2,023	-	-	-	-	-	-
375	Structures And Improvements	18	84,890	39,525	22,487	5,832	8,497	4,796	3,752	-	-	-	-	-	-
376	Mains - Small	4	13,681,072	6,751,609	3,841,645	995,982	1,451,562	-	640,274	-	-	-	-	-	-
	Mains - Large	4	25,153,185	12,413,097	7,063,014	1,831,152	2,668,753	-	1,177,169	-	-	-	-	-	-
	Mains - Direct Assign	DA	2,324,426					2,324,390	36						
378	Measuring & Regulating Equipment - General	18	5,960,845	2,775,369	1,579,028	409,510	596,681	336,788	263,469	-	-	-	-	-	-
379	Measuring & Regulating Equipment - City Gate	18	607,635	282,915	160,963	41,745	60,824	34,331	26,857	-	-	-	-	-	-
380	Services	6C	40,073,393	-	-	-	-	-	-	34,935,984	4,812,814	160,294	100,183	12,022	52,095
381	Meters	6	5,529,933	-	-	-	-	-	-	2,354,645	2,450,313	322,948	241,658	43,686	116,682
382	Meter Installations	6	3,015,930	-	-	-	-	-	-	1,284,183	1,336,359	176,130	131,796	23,826	63,636
383	House Regulators	6A	137,693	-	-	-	-	-	-	121,032	16,661	-	-	-	-
384	House Regulator Installations	6A	486,457	-	-	-	-	-	-	427,596	58,861	-	-	-	-
385	Industrial Measuring & Regulating Equipment	6	825,092	-	-	-	-	-	-	351,324	365,598	48,185	36,057	6,518	17,409
386	Other Property on Customer Premises	6C	23,675	-	-	-	-	-	-	20,640	2,843	95	59	7	31
387	Other Equipment	10	99,425	18,771	10,658	2,744	3,868	6,154	1,660	41,401	11,752	1,094	795	139	388
387.1	Other Equipment	10	4,177	789	448	115	162	259	70	1,739	494	46	33	6	16
	Total Distribution Plant		**98,053,598**	**22,303,386**	**12,690,367**	**3,290,224**	**4,794,929**	**2,709,304**	**2,115,310**	**39,538,544**	**9,055,695**	**708,792**	**510,581**	**86,204**	**250,257**
GENERAL PLANT															
390	Structures And Improvements	12	4,797,233	1,720,288	429,832	118,012	168,383	188,052	63,323	1,644,971	270,564	85,870	62,844	13,912	31,182
391	Office Furniture And Equipment	12	350,467	125,677	31,402	8,621	12,301	13,738	4,626	120,175	19,766	6,273	4,591	1,016	2,278
392	Transportation Equipment	12	5,308,101	1,903,485	475,606	130,579	186,314	208,078	70,067	1,820,148	299,377	95,015	69,536	15,393	34,503
393	Stores Equipment	12	834	299	75	21	29	33	11	286	47	15	11	2	5
394	Tools, Shop And Garage Equipment	12	2,080,239	745,974	186,389	51,174	73,016	81,545	27,459	713,314	117,325	37,236	27,251	6,033	13,522
395	Laboratory Equipment	12	22,097	7,924	1,980	544	776	866	292	7,577	1,246	396	289	64	144
396	Power Operated Equipment	12	446,936	160,271	40,045	10,995	15,687	17,520	5,900	153,254	25,207	8,000	5,855	1,296	2,905
397	Communication Equipment	12	106,929	38,345	9,581	2,630	3,753	4,192	1,411	36,666	6,031	1,914	1,401	310	695
398	Miscellaneous Equipment	12	315,221	113,038	28,244	7,754	11,064	12,357	4,161	108,089	17,778	5,642	4,129	914	2,049
	Total General Plant		**13,428,057**	**4,815,301**	**1,203,154**	**330,330**	**471,323**	**526,381**	**177,250**	**4,604,480**	**757,341**	**240,361**	**175,907**	**38,940**	**87,283**
COMMON PLANT ALLOCATED @ 88.43%															
390.2	Structures and Improvements	12	859,246	308,125	76,988	21,137	30,160	33,682	11,342	294,635	48,461	15,380	11,256	2,492	5,585
391	Office Furniture and Equipment	12	449,325	161,128	40,260	11,053	15,771	17,614	5,931	154,074	25,342	8,043	5,886	1,303	2,921
392.1	Transportation Equipment	12	-	-	-	-	-	-	-	-	-	-	-	-	-
398	Miscellaneous Equipment	12	2,858	1,025	256	70	100	112	38	980	161	51	37	8	19
	Total Common Plant		**1,311,428**	**470,278**	**117,504**	**32,260**	**46,031**	**51,408**	**17,311**	**449,689**	**73,964**	**23,474**	**17,179**	**3,803**	**8,525**
INFORMATION SERVICES (IS) ALLOCATED @ 91.68%															
391	Office Furniture and Equipment	12	13,161,549	4,719,731	1,179,275	323,774	461,970	515,933	173,732	4,513,095	742,311	235,592	172,416	38,168	85,550
391.1	Office Furniture and Equip. - New CIS Software	7	4,655,090	-	-	-	-	-	-	4,164,909	473,888	9,310	4,190	466	2,328
391.4	Office Furniture and Equip. - New CIS Software	12	2,705,627	970,238	242,424	66,558	94,968	106,061	35,714	927,759	152,597	48,431	35,444	7,846	17,587
	Total Information Services		**20,522,266**	**5,689,969**	**1,421,699**	**390,332**	**556,938**	**621,994**	**209,446**	**9,605,763**	**1,368,796**	**293,333**	**212,050**	**46,480**	**105,465**

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

	Account	Factor Ref.	Cost of Service	Volumetric Costs						Customer Costs					
				Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Less:															
	Amount Charged to Clearing Accounts	12	(8,371,000)	(3,001,841)	(750,042)	(205,927)	(293,822)	(328,143)	(110,497)	(2,870,416)	(472,124)	(149,841)	(109,660)	(24,276)	(54,412)
390.1	Reading Service Center Alloc. to Electric Div. @ 8.32%	12	(10,551)	(3,784)	(945)	(260)	(370)	(414)	(139)	(3,618)	(595)	(189)	(138)	(31)	(69)
390.1	Empire Building Alloc. To Electric Div. @ 13.07%	12	(35,345)	(12,675)	(3,167)	(869)	(1,241)	(1,386)	(467)	(12,120)	(1,993)	(633)	(463)	(103)	(230)
	Total Depreciation & Amortization Expense		**125,536,352**	**30,582,808**	**14,861,791**	**3,883,495**	**5,642,263**	**3,565,885**	**2,438,098**	**51,312,322**	**10,781,084**	**1,115,297**	**805,456**	**151,017**	**396,819**
TAXES OTHER THAN INCOME TAXES															
408.10	Capital Stock	15	-	-	-	-	-	-	-	-	-	-	-	-	-
408.10	County and Municipal Taxes	16	1,868,000	584,871	236,302	60,336	87,236	66,127	36,613	630,824	118,058	21,295	15,504	3,176	7,659
408.10	Payroll Related Tax	13	6,926,300	1,541,794	662,847	173,850	247,962	302,679	103,895	2,875,107	582,502	194,629	144,067	27,013	69,956
408.10	Public Utility Assessment	16	4,042,000	1,265,550	511,313	130,557	188,761	143,087	79,223	1,364,983	255,454	46,079	33,549	6,871	16,572
408.10	Public Utility Reality Tax	15	822,000	248,573	131,109	33,373	48,580	28,770	21,208	251,203	48,662	4,685	3,452	658	1,726
408.10	Miscellaneous Taxes	16	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Taxes Other Than Income		**13,658,300**	**3,640,788**	**1,541,571**	**398,116**	**572,539**	**540,663**	**240,939**	**5,122,117**	**1,004,676**	**266,688**	**196,572**	**37,718**	**95,913**
	Total Operating Expenses		**432,700,221**	**139,742,617**	**44,686,456**	**11,291,932**	**16,209,684**	**15,340,655**	**6,483,754**	**155,477,752**	**28,442,572**	**6,691,909**	**4,883,854**	**1,029,480**	**2,419,539**
INCOME TAXES		15	63,347,000	19,156,133	10,103,847	2,571,888	3,743,808	2,217,145	1,634,353	19,358,843	3,750,142	361,078	266,057	50,678	133,029
OPERATING INCOME AVAILABLE FOR RETURN		15	252,254,645	76,281,805	40,234,616	10,241,539	14,908,250	8,828,913	6,508,170	77,089,020	14,933,475	1,437,851	1,059,470	201,804	529,735
TOTAL COST OF SERVICE			**748,301,866**	**235,180,555**	**95,024,919**	**24,105,359**	**34,861,742**	**26,386,713**	**14,626,277**	**251,925,615**	**47,126,189**	**8,490,838**	**6,209,381**	**1,281,962**	**3,082,303**
Less: Other Revenues															
	Reconnection Charges	22	580,000	-	-	-	-	-	-	568,458	11,542	-	-	-	-
	Rent From Gas Property	12	2,686,000	963,200	240,666	66,076	94,279	105,291	35,455	921,029	151,490	48,079	35,187	7,789	17,459
	Forfieted Discounts/Penalties	23	5,603,000	-	-	-	-	-	-	2,966,228	1,899,977	242,050	276,228	118,223	100,294
	Other Miscellaneous Revenues	16	1,418,000	443,976	179,377	45,801	66,221	50,197	27,793	478,859	89,618	16,165	11,769	2,411	5,814
	Subtotal		10,287,000	1,407,176	420,043	111,877	160,500	155,488	63,248	4,934,574	2,152,627	306,294	323,184	128,423	123,567
TOTAL COST OF SERVICE RELATED TO TARIFF SALES AND TRANSPORTATION			**$ 738,014,866**	**$ 233,773,379**	**$ 94,604,876**	**$ 23,993,482**	**$ 34,701,242**	**$ 26,231,225**	**$ 14,563,029**	**$ 246,991,041**	**$ 44,973,562**	**$ 8,184,544**	**$ 5,886,197**	**$ 1,153,539**	**$ 2,958,736**

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTORS 1 and 1A. ALLOCATION OF COSTS WHICH VARY DIRECTLY WITH PGC AND CHOICE SALES.

Factors are based on the pro forma average daily PGC sales volumes for each service classification.

Service Classification	Pro Forma Average Daily PGC Volumes (Mcf)	Allocation Factor 1	PGC and Choice Volumes (Mcf)	Allocation Factor 1A
(1)	(2)	(3)		
Volumetric Costs				
Rate R	124,315	0.7176	142,485	0.6257
Rate N	48,925	0.2824	85,232	0.3743
Rate DS		-		
Rate LFD		-		
Rate XD	-	-		
Interruptible	-	-		
Total	173,240	1.0000	227,717	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTORS 2 . ALLOCATION OF COMPRESSOR STATION FUEL.

Factors are based on the pro forma average daily throughput volumes for each service classification.

Service Classification	Pro Forma Average Daily Throughput Volumes (Mcf)	Allocation Factor 2
(1)	(2)	(3)
Volumetric Costs		
Rate R	142,485	0.1529
Rate N	85,232	0.0914
Rate DS	26,335	0.0282
Rate LFD	64,765	0.0694
Rate XD Firm	571,442	0.6127
Interruptible	42,334	0.0454
Total	932,593	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTORS 3 and 3A. CALCULATION OF MAXIMUM DAY EXTRA DEMAND FACTORS.

Factors are based on the maximum day extra demand throughput for each classification.

Service Classification	Pro Forma Average Daily Throughput Volumes (Mcf)	Peak Day Capacity (Mcf)	Extra Capacity (Mcf)	Allocation Factor 3	Allocation Factor 3A
(1)	(2)	(3)	(4)=(3)-(2)	(5)	(6)
Volumetric Costs					
Rate R	142,485	691,772	549,287	0.4486	0.5635
Rate N	85,232	389,541	304,309	0.2485	0.3122
Rate DS	26,335	96,848	70,513	0.0576	0.0723
Rate LFD	64,765	115,419	50,654	0.0414	0.0520
Subtotal	318,817	1,293,580	974,763	0.7961	1.0000
Rate XD Firm	571,442	821,122	249,680	0.2039	-
Total	890,259	2,114,702	1,224,443	1.0000	1.0000
Firm Service Load Factor	0.4210		0.5790		

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 4. ALLOCATION OF COSTS ASSOCIATED WITH TRANSMISSION AND LARGE DISTRIBUTION MAINS.

Factors are based on the weighting of the factors derived from average daily throughput volumes volumes and from maximum day extra capacity demand for each service classification, as follows:

	Average Daily Throughput			Maximum Day Extra Demand		
Service Classification	MCF/Day	Allocation Factor	Weighted Factor*	Allocation Factor 3A	Weighted Factor*	Allocation Factor 4
(1)	(2)	(3)	(4)=(3)x 0.4210	(5)	(6)=(5)x 0.5790	(7)=(4)+(6)
Volumetric Costs						
Rate R	142,485	0.3973	0.1673	0.5635	0.3262	0.4935
Rate N	85,232	0.2376	0.1000	0.3122	0.1808	0.2808
Rate DS	26,335	0.0734	0.0309	0.0723	0.0419	0.0728
Rate LFD	64,765	0.1806	0.0760	0.0520	0.0301	0.1061
Rate XD Firm		-	-	-	-	-
Interruptible**	39,847	0.1111	0.0468		-	0.0468
Total	358,664	1.0000	0.4210	1.0000	0.5790	1.0000

* The weighting of the factors is based on the system load factor for firm service. See Factor 3.
** Excludes XD-I volumes for customers who are 100% interruptible.

FACTOR 4A. ALLOCATION OF COSTS ASSOCIATED WITH LOAD DISPATCHING AND M&R STATION EQUIPMENT.

Factors are based on the weighting of the factors derived from average daily throughput volumes and from maximum day extra capacity demand for each service classification, as follows:

		Average Daily Throughput		Maximum Day Extra Demand		
Service Classification	Throughput	Allocation Factor 2	Weighted Factor	Allocation Factor 3	Weighted Factor	Allocation Factor
(1)	(2)	(3)	(4)=(3)x 0.4410	(5)	(6)=(5)x 0.5590	(7)=(4)+(6)
Volumetric						
Rate R	142,485	0.1529	0.0675	0.4486	0.2508	0.3183
Rate N	85,232	0.0914	0.0403	0.2485	0.1389	0.1792
Rate DS	26,335	0.0282	0.0124	0.0576	0.0322	0.0446
Rate LFD	64,765	0.0694	0.0306	0.0414	0.0231	0.0537
Rate XD-Firm	571,442	0.6127	0.2702	0.2039	0.1140	0.3842
Interruptible	42,334	0.0454	0.0200	-	-	0.0200
Total	932,593	1.0000	0.4410	1.0000	0.5590	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 5. NOT USED IN THIS ALLOCATION.

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 6. ALLOCATION OF COSTS ASSOCIATED WITH ACCOUNTS 381 and 385.

Factors are based on the cost of meters by class included in Accounts 381 and 385, Meters and M&R Equipment.

Service Classification	Meter Costs SDR-COS-7	Allocation Factor
(1)		(1)
Customer Costs		
Rate R	$ 75,859,636	0.4258
Rate N	78,928,022	0.4431
Rate DS	10,405,903	0.0584
Rate LFD	7,783,898	0.0437
Rate XD-Firm	1,404,538	0.0079
Interruptible	3,754,266	0.0211
Total	$ 178,136,264	1.0000

FACTOR 6A. ALLOCATION OF COSTS ASSOCIATED WITH HOUSE REGULATORS

Factors are based on the number of weighted house regulators for customers served.

Service Classification	Number of Regulators	Factor	Weighted Regulators	Allocation Factor
(1)	(2)	(3)	(4)	(5)
Customer				
Rate R	616,132	1.00	616,132	0.8790
Rate N	70,125	1.21	84,851	0.1210
Total	686,257		700,983	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 6B. ALLOCATION OF COSTS ASSOCIATED WITH INDUSTRIAL MEASURING AND REGULATING EQUIPMENT.

Factors are based on the cost of Meters and M&R equipment by class included in Accounts 381 and 385.

Service Classification	Cost of Meters & M&R Equipment	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate DS	$ 10,405,903	0.4456
Rate LFD	7,783,898	0.3334
Rate XD - Firm	1,404,538	0.0602
Interruptible	3,754,266	0.1608
Total	$ 23,348,605	1.0000

FACTOR 6C. ALLOCATION OF COSTS ASSOCIATED WITH SERVICES.

Factors are based on the cost of services by class included in Account 380, Service Lines.

Service Classification	Cost of Service Lines SDR-COS-6	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 1,141,965,038	0.8718
Rate N	157,264,701	0.1201
Rate DS	5,215,208	0.0040
Rate LFD	3,245,947	0.0025
Rate XD - Firm	402,109	0.0003
Interruptible	1,670,210	0.0013
Total	$ 1,309,763,212	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 7. ALLOCATION OF COSTS ASSOCIATED WITH CUSTOMER ACCOUNTING AND METER READING.

Factors are based on the number of customers for each classification, as follows.

Service Classification	Number of Customers	Allocation Factor 7	Allocation Factor 7A
(1)	(2)	(3)	(4)
Customer Costs			
Rate R	616,132	0.8947	
Rate N	70,125	0.1018	
Rate DS	1,392	0.0020	0.5769
Rate LFD	602	0.0009	0.2495
Rate XD Firm	56	0.0001	0.0232
Interruptible	363	0.0005	0.1504
Total	688,670	1.0000	1.0000

FACTOR 8. ALLOCATION OF COSTS ASSOCIATED WITH SALES EXPENSES.

Factors are based on the number of Rate R and Rate N customers.

Service Classification	Number of Customers	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	616,132	0.8978
Rate N	70,125	0.1022
Total	686,257	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 9 (DA). ALLOCATION OF CUSTOMER ASSISTANCE EXPENSES.

These costs are directly assigned to the Residential Classification.

Service Classification	Allocation Factor
(1)	(3)
Customer Costs	
Rate R	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 10. ALLOCATION OF DISTRIBUTION OPERATION OTHER EXPENSES AND RENT.

Factors are based on distribution operation expenses other than those being allocated

Service Classification	Operation Expenses	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 7,162,515	0.1888
Rate N	4,066,104	0.1072
Rate DS	1,045,861	0.0276
Rate LFD	1,475,450	0.0389
Rate XD Firm	2,347,881	0.0619
Interruptible	634,553	0.0167
Customer Costs		
Rate R	15,798,827	0.4164
Rate N	4,484,957	0.1182
Rate DS	416,872	0.0110
Rate LFD	304,448	0.0080
Rate XD Firm	52,729	0.0014
Interruptible	148,409	0.0039
Total	$ 37,938,606	1.0000

FACTOR 11. ALLOCATION OF DISTRIBUTION MAINTENANCE OTHER EXPENSES.

Factors are based on distribution maintenance expenses other than those being allocated

Service Classification	Maintenance Expenses	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 14,363,506	0.3771
Rate N	8,164,150	0.2143
Rate DS	2,109,995	0.0554
Rate LFD	3,038,765	0.0798
Rate XD Firm	2,808,455	0.0737
Interruptible	1,327,745	0.0349
Customer Costs		
Rate R	1,348,688	0.0354
Rate N	185,797	0.0049
Rate DS	2,115,156	0.0555
Rate LFD	1,581,808	0.0415
Rate XD Firm	285,383	0.0075
Interruptible	763,057	0.0200
Total	$ 38,092,505	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 12. ALLOCATION OF ADMINISTRATIVE AND GENERAL EXPENSES.

Factors are based on the allocation of operation and maintenance expenses.

Service Classification (1)	Operation & Maintenance Expenses (2)	Allocation Factor (3)
Volumetric Costs		
Rate R	$ 58,569,126	0.3586
Rate N	14,629,664	0.0896
Rate DS	4,017,934	0.0246
Rate LFD	5,724,826	0.0351
Rate XD Firm	6,401,934	0.0392
Interruptible	2,162,015	0.0132
Customer Costs		
Rate R	56,004,797	0.3429
Rate N	9,214,100	0.0564
Rate DS	2,926,548	0.0179
Rate LFD	2,132,347	0.0131
Rate XD Firm	469,409	0.0029
Interruptible	1,063,709	0.0065
Total	$ 163,316,408	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 13. ALLOCATION OF LABOR RELATED TAXES AND BENEFITS.

Factors are based on the allocation of total operation and maintenance direct labor expense to service classifications as shown on the following page.

Service Classification	Total Labor Expense	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 18,312,249	0.2226
Rate N	7,867,569	0.0957
Rate DS	2,061,897	0.0251
Rate LFD	2,939,373	0.0358
Rate XD Firm	3,594,917	0.0437
Interruptible	1,229,259	0.0150
Customer Costs		
Rate R	34,118,262	0.4151
Rate N	6,908,762	0.0841
Rate DS	2,308,634	0.0281
Rate LFD	1,706,775	0.0208
Rate XD Firm	317,757	0.0039
Interruptible	829,294	0.0101
Total	$ 82,194,748	1.0000

FACTOR 14. ALLOCATION OF ORGANIZATION, FRANCHISES AND CONSENTS, MISCELLANEOUS INTANGIBLE PLANT AND OTHER RATE BASE ELEMENTS.

Factors are based on the allocation of the original cost less depreciation excluding the items being allocated, as follows:

Service Classification	Original Cost Less Depreciation	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$1,148,435,746	0.3024
Rate N	605,368,694	0.1595
Rate DS	154,068,783	0.0406
Rate LFD	224,236,709	0.0591
Rate XD Firm	132,940,846	0.0350
Interruptible	98,011,819	0.0258
Customer Costs		
Rate R	1,159,977,329	0.3055
Rate N	224,664,245	0.0592
Rate DS	21,838,658	0.0058
Rate LFD	15,830,903	0.0042
Rate XD Firm	3,018,638	0.0008
Interruptible	7,966,806	0.0021
Total	$3,796,359,176	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 15. ALLOCATION OF RETURN AND TAXES.

Factors are based on the result of allocating the original cost measure of value, as presented on the following pages.

Service Classification	Original Cost Less Depreciation	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 958,730,325	0.3024
Rate N	505,307,272	0.1595
Rate DS	128,598,637	0.0406
Rate LFD	187,160,695	0.0591
Rate XD Firm	110,984,157	0.0350
Interruptible	81,826,312	0.0258
Customer Costs		
Rate R	968,326,817	0.3056
Rate N	187,525,890	0.0592
Rate DS	18,200,333	0.0057
Rate LFD	13,196,255	0.0042
Rate XD Firm	2,516,808	0.0008
Interruptible	6,649,483	0.0021
Total	$ 3,169,022,984	1.0000

FACTOR 16. ALLOCATION OF REGULATORY COMMISSION EXPENSES, ASSESSMENTS AND OTHER REVENUES.

Factors are based on the allocated cost of service excluding those items being allocated.

Service Classification	Total Cost of Service	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 231,286,751	0.3131
Rate N	93,469,244	0.1265
Rate DS	23,875,932	0.0323
Rate LFD	34,530,032	0.0467
Rate XD Firm	26,135,267	0.0354
Interruptible	14,487,058	0.0196
Customer Costs		
Rate R	249,526,932	0.3377
Rate N	46,677,279	0.0632
Rate DS	8,409,864	0.0114
Rate LFD	6,150,426	0.0083
Rate XD Firm	1,269,887	0.0017
Interruptible	3,053,181	0.0041
Total	$ 738,871,852	1.0000

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

	Account	Factor Ref.	Cost of Service	Volumetric Costs						Customer Costs					
				Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
RATE BASE															
PRODUCTION PLANT															
305	Manufactured Gas Plant Site Remdiation	2	(69,118)	(10,568)	(6,317)	(1,949)	(4,797)	(42,349)	(3,138)	-	-	-	-	-	-
325.1	Producing Lands	2	13,029	1,992	1,191	367	904	7,983	592	-	-	-	-	-	-
325.2	Production Leaseholds	2	965	148	88	27	67	591	44	-	-	-	-	-	-
325.4	Rights-Of-Way	2	560	86	51	16	39	343	25	-	-	-	-	-	-
325.5	Other Lands	2	1,134	173	104	32	79	695	51	-	-	-	-	-	-
328	Field Measuring and Regulating Station Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Other Structures	2	2	-	-	-	-	1	-	-	-	-	-	-	-
330	Producing Gas Wells - Well Construction	2	-	-	-	-	-	-	-	-	-	-	-	-	-
331	Producing Gas Wells - Well Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
332	Field Lines	2	23,897	3,654	2,184	674	1,658	14,642	1,085	-	-	-	-	-	-
334	Field Measuring and Regulating Station Equipment	2	4,352	665	398	123	302	2,666	198	-	-	-	-	-	-
335	Drilling and Cleaning Equipment	2	101	15	9	3	7	62	5	-	-	-	-	-	-
337	Other Equipment	2	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Production Plant		(25,078)	(3,835)	(2,292)	(707)	(1,741)	(15,366)	(1,138)	-	-	-	-	-	-
STORAGE PLANT															
352.01	Well Construction	2	35,934	5,494	3,284	1,013	2,494	22,017	1,631	-	-	-	-	-	-
TRANSMISSION PLANT															
365	Land	4	47,323	23,354	13,288	3,445	5,021	-	2,215	-	-	-	-	-	-
365.2	Rights-Of-Way	4	319,697	157,770	89,771	23,274	33,920	-	14,962	-	-	-	-	-	-
366	Structures and Improvements	4	14,665	7,237	4,118	1,068	1,556	-	686	-	-	-	-	-	-
367	Mains	4	16,728,788	8,255,657	4,697,444	1,217,856	1,774,924	-	782,907	-	-	-	-	-	-
369	Measuring and Regulating Staion Equipment	4	2,093,133	1,032,961	587,752	152,380	222,081	-	97,959	-	-	-	-	-	-
370	Communication Equipment	4	1,241,718	612,788	348,674	90,397	131,746	-	58,112	-	-	-	-	-	-
371	Other Equipment	4	9,919	4,895	2,785	722	1,052	-	464	-	-	-	-	-	-
371.1	Testing Equipment	4	52,388	25,853	14,711	3,814	5,558	-	2,452	-	-	-	-	-	-
	Total Transmission Plant		20,507,631	10,120,515	5,758,543	1,492,956	2,175,858	-	959,757	-	-	-	-	-	-
DISTRIBUTION PLANT															
374	Land	18	849,347	395,456	224,992	58,350	85,020	47,988	37,541	-	-	-	-	-	-
374	Land Rights of Way	18	7,305,824	3,401,592	1,935,313	501,910	731,313	412,779	322,917	-	-	-	-	-	-
374	Rights of Way	4	2,117,511	1,044,992	594,597	154,155	224,668	-	99,100	-	-	-	-	-	-
375	Structures And Improvements	18	2,211,379	1,029,618	585,794	151,922	221,359	124,943	97,743	-	-	-	-	-	-
376	Mains - Small	4	627,708,395	309,774,093	176,260,517	45,697,171	66,599,861	-	29,376,753	-	-	-	-	-	-
	Mains - Large	4	1,154,066,353	569,531,745	324,061,832	84,016,030	122,446,440	-	54,010,305	-	-	-	-	-	-
	Mains - Direct Assign	DA	106,648,197					106,646,558	1,639						
378	Measuring & Regulating Equipment - General	18	160,502,424	74,729,929	42,517,092	11,026,517	16,066,293	9,068,387	7,094,207	-	-	-	-	-	-
379	Measuring & Regulating Equipment - SCADA	18	-	-	-	-	-	-	-	-	-	-	-	-	-
379	Measuring & Regulating Equipment - City Gate	18	16,602,462	7,730,106	4,397,992	1,140,589	1,661,906	938,039	733,829	-	-	-	-	-	-
380	Services	6C	1,027,231,351	-	-	-	-	-	-	895,540,292	123,370,485	4,108,925	2,568,078	308,169	1,335,401
381	Meters	6	105,716,315	-	-	-	-	-	-	45,014,007	46,842,899	6,173,833	4,619,803	835,159	2,230,614
382	Meter Installations	6	70,230,279	-	-	-	-	-	-	29,904,053	31,119,037	4,101,448	3,069,063	554,819	1,481,859
383	House Regulators	6A	3,612,616	-	-	-	-	-	-	3,175,489	437,127	-	-	-	-
384	House Regulator Installations	6A	9,602,363	-	-	-	-	-	-	8,440,477	1,161,886	-	-	-	-
385	Industrial Measuring & Regulating Equipment	6	21,540,899	-	-	-	-	-	-	9,172,115	9,544,772	1,257,989	941,337	170,173	454,513
386	Other Property on Customer Premises	6C	427,942	-	-	-	-	-	-	373,080	51,396	1,712	1,070	128	556
387	Other Equipment	10	1,836,670	346,763	196,891	50,692	71,446	113,690	30,672	764,789	217,094	20,203	14,693	2,571	7,163
387	Other Equipment - Graphic Data Base	10	17,592	3,321	1,886	486	684	1,089	294	7,325	2,079	194	141	25	69
	Total Distribution Plant		3,318,227,919	967,987,615	550,776,906	142,797,822	208,108,990	117,353,473	91,805,000	992,391,627	212,746,775	15,664,304	11,214,185	1,871,044	5,510,175
GENERAL PLANT															
389	Land and Land Rights	12	10,370,785	3,718,964	929,222	255,121	364,015	406,535	136,894	3,556,142	584,912	185,637	135,857	30,075	67,410
390	Structures And Improvements	12	87,164,154	31,257,066	7,809,908	2,144,238	3,059,462	3,416,835	1,150,567	29,888,588	4,916,058	1,560,238	1,141,850	252,776	566,567
391	Office Furniture And Equipment	12	4,091,487	1,467,207	366,597	100,651	143,611	160,386	54,008	1,402,971	230,760	73,238	53,598	11,865	26,595
392	Transportation Equipment	12	37,116,223	13,309,878	3,325,614	913,059	1,302,779	1,454,956	489,934	12,727,153	2,093,355	664,380	486,223	107,637	241,255
393	Stores Equipment	12	10,407	3,732	932	256	365	408	137	3,569	587	186	136	30	68
394	Tools, Shop And Garage Equipment	12	26,008,960	9,326,813	2,330,403	639,820	912,914	1,019,551	343,318	8,918,472	1,466,905	465,560	340,717	75,426	169,058
393	Laboratory Equipment	12	303,522	108,843	27,196	7,467	10,654	11,898	4,006	104,078	17,119	5,433	3,976	880	1,973
396	Power Operated Equipment	12	3,682,716	1,320,622	329,971	90,595	129,263	144,362	48,612	1,262,803	207,705	65,921	48,244	10,680	23,938
397	Communication Equipment	12	428,059	153,502	38,354	10,530	15,025	16,780	5,650	146,781	24,143	7,662	5,608	1,241	2,782
398	Miscellaneous Equipment	12	1,155,077	414,211	103,495	28,415	40,543	45,279	15,247	396,076	65,146	20,676	15,132	3,350	7,508
	Total General Plant		170,331,390	61,080,838	15,261,692	4,190,152	5,978,631	6,676,990	2,248,373	58,406,633	9,606,690	3,048,931	2,231,341	493,960	1,107,154
	Total Plant		3,509,077,796	1,039,190,627	571,798,133	148,481,236	216,264,232	124,037,114	95,013,623	1,050,798,260	222,353,465	18,713,235	13,445,526	2,365,004	6,617,329

UGI UTILITIES INC. - GAS DIVISION

COST OF SERVICE AS OF SEPTEMBER 30, 2023, AT PROPOSED REVENUE LEVEL ALLOCATED TO
RATE R, RATE N, RATE DS, RATE LFD, RATE XD-FIRM, AND INTERRUPTIBLE SERVICE CLASSIFICATIONS

				Volumetric Costs						Customer Costs					
Account		Factor Ref.	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
COMMON PLANT ALLOCATED @ 88.97%															
301	Organization	14	123,636	37,388	19,720	5,020	7,307	4,327	3,190	37,771	7,319	717	519	99	260
389.1	Land and Land Rights	12	6,180,842	2,216,450	553,803	152,049	216,948	242,289	81,587	2,119,411	348,599	110,637	80,969	17,924	40,175
390.1	Reading Service Center	12	3,662,434	1,313,349	328,154	90,096	128,551	143,567	48,344	1,255,848	206,561	65,558	47,978	10,621	23,806
390.2	Structures and Improvements	12	27,482,527	9,855,234	2,462,434	676,070	964,637	1,077,315	362,769	9,423,758	1,550,015	491,937	360,021	79,699	178,636
391	Office Furniture and Equipment	12	3,324,746	1,192,254	297,897	81,789	116,699	130,330	43,887	1,140,055	187,516	59,513	43,554	9,642	21,611
392.1	Transportation Equipment	12	-	-	-	-	-	-	-	-	-	-	-	-	-
398	Miscellaneous Equipment	12	18,573	6,660	1,664	457	652	728	245	6,369	1,048	332	243	54	121
	Total Common Plant		40,792,758	14,621,335	3,663,672	1,005,481	1,434,794	1,598,556	540,022	13,983,212	2,301,058	728,694	533,284	118,039	264,609
INFORMATION SERVICES (IS) ALLOCATED @ 91.68%															
391	Office Furniture and Equipment	12	2,279,539	817,443	204,247	56,077	80,012	89,358	30,090	781,654	128,566	40,804	29,862	6,611	14,817
391.1	Office Furniture and Equip. - CIS	7	40,732,041	-	-	-	-	-	-	36,442,957	4,146,522	81,464	36,659	4,073	20,366
391.2	Office Furniture and Equip. - System Development Cost	12	90,319,674	32,388,635	8,092,643	2,221,864	3,170,221	3,540,531	1,192,220	30,970,616	5,094,030	1,616,722	1,183,188	261,927	587,078
391.4	Office Furniture and Equip. - System Development Cost	12	39,231,589	14,068,448	3,515,150	965,097	1,377,029	1,537,878	517,857	13,452,512	2,212,662	702,245	513,934	113,772	255,005
	Total Information Services		172,562,843	47,274,526	11,812,040	3,243,038	4,627,262	5,167,767	1,740,167	81,647,739	11,581,780	2,441,235	1,763,643	386,383	877,266
INTANGIBLE PLANT															
301	Organization	14	166,478	50,343	26,553	6,759	9,839	5,827	4,295	50,859	9,855	966	699	133	350
302	Franchises And Consents	14	193,597	58,544	30,879	7,860	11,442	6,776	4,995	59,144	11,461	1,123	813	155	407
303	Miscellaneous Intangible Plant	14	289,868	87,656	46,234	11,769	17,131	10,145	7,479	88,555	17,160	1,681	1,217	232	609
304	Land and Land Rights	14	381,652	115,412	60,873	15,495	22,556	13,358	9,847	116,595	22,594	2,214	1,603	305	801
305	Manufactured Gas Plant Remediation	1	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Nondepreciable Plant		1,031,595	311,955	164,539	41,883	60,968	36,106	26,616	315,153	61,070	5,984	4,332	825	2,167
	Total Utility Plant in Service		3,723,464,991	1,101,398,443	587,438,384	152,771,638	222,387,256	130,839,543	97,320,428	1,146,744,364	236,297,373	21,889,148	15,746,785	2,870,251	7,761,371
OTHER RATE BASE ELEMENTS															
	Gas Storage Inventory	1A	17,813,000	11,145,594	6,667,406	-	-	-	-	-	-	-	-	-	-
	Cash Working Capital	12	38,947,696	13,966,644	3,489,714	958,113	1,367,064	1,526,750	514,110	13,355,165	2,196,650	697,164	510,215	112,948	253,160
	Cash Working Capital - Purchased Gas Related	1	23,200,304	16,648,538	6,551,766	-	-	-	-	-	-	-	-	-	-
	Materials & Supplies	12	15,707,000	5,632,530	1,407,347	386,392	551,316	615,714	207,332	5,385,930	885,875	281,155	205,762	45,550	102,096
	Deferred Taxes	14	(628,510,000)	(190,061,424)	(100,247,345)	(25,517,506)	(37,144,941)	(21,997,850)	(16,215,558)	(192,009,805)	(37,207,792)	(3,645,358)	(2,639,742)	(502,808)	(1,319,871)
	Customer Deposits	21	(21,600,000)	-	-	-	-	-	-	(5,148,837)	(14,646,216)	(1,021,776)	(626,765)	(9,133)	(147,273)
	Investment Tax Credit	14	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Other Rate Base Elements		(554,442,000)	(142,668,118)	(82,131,112)	(24,173,001)	(35,226,561)	(19,855,386)	(15,494,116)	(178,417,547)	(48,771,483)	(3,688,815)	(2,550,530)	(353,443)	(1,111,888)
	Total Measure of Value		**$ 3,169,022,991**	**$ 958,730,325**	**$ 505,307,272**	**$128,598,637**	**$ 187,160,695**	**$ 110,984,157**	**$ 81,826,312**	**$ 968,326,817**	**$ 187,525,890**	**$ 18,200,333**	**$ 13,196,255**	**$ 2,516,808**	**$ 6,649,483**

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 17. ALLOCATION OF OPERATION AND MAINTENANCE EXPENSES ASSOCIATED WITH LARGE MAINS.

Factors are based on the allocation of rate base for large and directly assigned mains.

Service Classification	Original Cost Less Depreciation	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 569,531,745	0.4519
Rate N	324,061,832	0.2570
Rate DS	84,016,030	0.0666
Rate LFD	122,446,440	0.0971
Rate XD Firm	106,646,558	0.0846
Interruptible	54,011,944	0.0428
Total	$ 1,260,714,549	1.0000

FACTOR 18. ALLOCATION OF RATE BASE ASSOCIATED WITH M&R STATION EQUIPMENT AND OTHER DISTRIBUTION ASSETS.

Factors are based on the composite allocation of all mains.

Service Classification	Original Cost Less Depreciation	Allocation Factor
(1)	(2)	(3)
Volumetric Costs		
Rate R	$ 879,305,838	0.4656
Rate N	500,322,349	0.2649
Rate DS	129,713,201	0.0687
Rate LFD	189,046,301	0.1001
Rate XD Firm	106,646,558	0.0565
Interruptible	83,388,697	0.0442
Total	$ 1,888,422,944	1.0000

UGI UTILITIES, INC. - GAS DIVISION

FACTORS FOR ALLOCATING COST OF SERVICE TO SERVICE CLASSIFICATIONS

FACTOR 19. ALLOCATION OF UNCOLLECTIBLE ACCOUNTS.

Factors are based on history of net write-offs by class.

Service Classification	3-Yr. Average of Net Write-offs	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 10,714,163	0.9251
Rate N	749,312	0.0647
Rate DS	8,837	0.0008
Rate LFD	19,905	0.0017
Rate XD Firm	64,418	0.0056
Interruptible	24,812	0.0021
Total	$ 11,581,448	1.0000

FACTOR 20. ALLOCATION OF PENALTY REVENUE.

Factors are based on an analysis of penalty revenue, by class.

Service Classification	Penalty Revenue	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 2,313,287	0.4737
Rate N	1,885,751	0.3861
Rate DS	240,168	0.0492
Rate LFD	264,015	0.0541
Rate XD Firm	91,116	0.0187
Interruptible	89,186	0.0183
Total	$ 4,883,522	1.0000

FACTOR 21. ALLOCATION OF CUSTOMER DEPOSITS.

Factors are based on an analysis of customer deposits for 2021, by class.

Service Classification	2021 Customer Deposits	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 4,510,000	0.2384
Rate N	12,829,000	0.6781
Rate DS	895,000	0.0473
Rate LFD	549,000	0.0290
Rate XD Firm	8,000	0.0004
Interruptible	129,000	0.0068
Total	$ 18,920,000	1.0000

FACTOR 22. ALLOCATION OF RECONNECTION FEES

Factors are based on an analysis of reconnection fees from February 1, 2021 thru January 31, 2022

Service Classification	Reconnection Fees	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 1,314,284	0.9801
Rate N	26,748	0.0199
Rate DS	-	-
Rate LFD	-	-
Rate XD Firm	-	-
Interruptible	-	-
Total	$ 1,341,032	1.0000

FACTOR 23. ALLOCATION OF FORFEITED DISCOUNTS

Factors are based on an analysis of forfeited discounts from February 1, 2021 thru January 31, 2022

Service Classification	Forfeited Discounts	Allocation Factor
(1)	(2)	(3)
Customer Costs		
Rate R	$ 2,778,458	0.5294
Rate N	1,779,387	0.3391
Rate DS	226,702	0.0432
Rate LFD	258,963	0.0493
Rate XD Firm	110,534	0.0211
Interruptible	93,796	0.0179
Total	$ 5,247,840	1.0000

UGI UTILITIES, INC. - GAS DIVISION

CALCULATION OF CUSTOMER COSTS PER BILL BY SERVICE CLASSIFICATION

		Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD Firm	Interruptible
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Fully Allocated Customer Costs								
Customer Costs		310,147,618	$ 246,991,041	$ 44,973,562	$ 8,184,544	$ 5,886,197	$ 1,153,539	$ 2,958,736
Number of bills		8,264,040	7,393,584	841,500	16,704	7,224	672	4,356
Customer Cost per bill			**$ 33.41**	**$ 53.44**	**$ 489.98**	**$ 814.81**	**$ 1,716.58**	**$ 679.23**
Direct Customer Costs								
O & M Expenses:								
874	Mains And Services Expenses							
	Mains	-	-	-	-	-	-	-
	Services	15,189,242	13,241,981	1,824,228	60,757	37,973	4,557	19,746
876	M & R Station Expenses - Industrial	12,194	-	-	5,434	4,065	734	1,961
878	Meter and House Regulator Expenses	3,245,151	1,381,785	1,437,926	189,517	141,813	25,637	68,473
879	Customer Installations Expenses	2,759,655	1,175,061	1,222,803	161,164	120,597	21,801	58,229
890	M & R Equip - Industrial	4,732,873	-	-	2,108,968	1,577,940	284,919	761,046
892	Services	1,547,016	1,348,688	185,797	6,188	3,868	464	2,011
893	Meters & House Regulators	-	-	-	-	-	-	-
901	Supervision	832,202	744,572	84,718	1,664	749	83	416
902	Meter Reading Expenses	2,208,095	1,975,583	224,784	4,416	1,987	221	1,104
903	Customer Records & Coll Expenses	19,474,018	17,423,404	1,982,455	38,948	17,527	1,947	9,737
903.1	Universal Service Program	-	-	-	-	-	-	-
904	Uncollectible Accounts	10,999,710	10,147,842	668,697	14,366	30,529	100,565	37,712
905	Miscellaneous Cust Accts Expenses	2,318,248	2,074,137	235,998	4,636	2,086	232	1,159
907	Supervision	174,406	156,041	17,755	349	157	17	87
908	Customer Assistance Expenses	714,061	714,061	-	-	-	-	-
910	Miscellaneous Customer Service Exp.	-	-	-	-	-	-	-
911	Supervision	431,364	387,279	44,085	-	-	-	-
912	Demonstrating and Selling Expenses	(677,610)	(608,358)	(69,252)	-	-	-	-
912.1	Energy Efficiency and Conservation	283,600	-	-	163,609	70,758	6,580	42,653
913	Advertising Expenses	1,637,284	1,469,954	167,330	-	-	-	-
916	Miscellaneous	258,000	231,632	26,368	-	-	-	-
926	Employee Pensions and Benefits	12,596,661 *	9,302,391	1,884,681	629,721	466,128	87,399	226,341
408	Payroll Taxes	3,893,274 *	2,875,107	582,502	194,629	144,067	27,013	69,956
	Subtotal O & M Expenses	82,629,444	64,041,160	10,520,875	3,584,366	2,620,244	562,169	1,300,631

UGI UTILITIES, INC. - GAS DIVISION

CALCULATION OF CUSTOMER COSTS PER BILL BY SERVICE CLASSIFICATION

		Cost of Service (1)	Rate R (2)	Rate N (3)	Rate DS (4)	Rate LFD (5)	Rate XD Firm (6)	Interruptible (7)
Depreciation Expense								
380	Services	40,073,392	34,935,984	4,812,814	160,294	100,183	12,022	52,095
381	Meters	5,529,932	2,354,645	2,450,313	322,948	241,658	43,686	116,682
382	Meter Installations	3,015,930	1,284,183	1,336,359	176,130	131,796	23,826	63,636
383	House Regulators	137,693	121,032	16,661	-	-	-	-
384	House Regulator Installations	486,457	427,596	58,861	-	-	-	-
385	Industrial M & R Equipment	825,091	351,324	365,598	48,185	36,057	6,518	17,409
390	Structures and Improvements	2,109,343 *	1,644,971	270,564	85,870	62,844	13,912	31,182
391	Office Furniture And Equipment	11,983,555 *	9,880,012	1,413,904	307,649	222,527	48,799	110,664
Subtotal Depreciation		64,161,393	50,999,747	10,725,074	1,101,076	795,065	148,763	391,668
Rate Base								
380	Services	1,027,231,350	895,540,292	123,370,485	4,108,925	2,568,078	308,169	1,335,401
381	Meters	105,716,315	45,014,007	46,842,899	6,173,833	4,619,803	835,159	2,230,614
382	Meter Installations	70,230,279	29,904,053	31,119,037	4,101,448	3,069,063	554,819	1,481,859
383	House Regulators	3,612,616	3,175,489	437,127	-	-	-	-
384	House Regulator Installations	9,602,363	8,440,477	1,161,886	-	-	-	-
385	Industrial M & R Equipment	21,540,899	9,172,115	9,544,772	1,257,989	941,337	170,173	454,513
390	Structures And Improvements	38,326,077 *	29,888,588	4,916,058	1,560,238	1,141,850	252,776	566,567
391	Office Furniture and Equipment	101,958,964 *	84,190,765	12,000,056	2,573,986	1,860,795	407,890	925,472
	Deferred Taxes	(237,325,376) *	(192,009,805)	(37,207,792)	(3,645,358)	(2,639,742)	(502,808)	(1,319,871)
	Customer Deposits	(21,600,000)	(5,148,837)	(14,646,216)	(1,021,776)	(626,765)	(9,133)	(147,273)
Subtotal Rate Base		1,119,293,487	908,167,144	177,538,312	15,109,285	10,934,419	2,017,045	5,527,282
Taxes and Return @ 10.0%		111,469,960	90,443,978	17,680,965	1,504,727	1,088,954	200,877	550,460
Total Direct Customer Costs		$ 258,260,797	$ 205,484,884	$ 38,926,913	$ 6,190,169	$ 4,504,263	$ 911,809	$ 2,242,759
Number of bills		8,264,040	7,393,584	841,500	16,704	7,224	672	4,356
Direct Costs per bill			**$ 27.79**	**$ 46.26**	**$ 370.58**	**$ 623.51**	**$ 1,356.86**	**$ 514.87**

* Customer cost portion of account.

UGI UTILITIES, INC. - GAS DIVISION

CALCULATION OF COSTS RELATED TO LFD AND XD DEMAND CHARGES

Capital Costs	Rate LFD	Rate XD Firm
Depreciation	$ 5,642,263	$ 3,565,885
Taxes Other Than Income	572,539	540,663
Income Taxes	3,743,808	2,217,145
Income Available for Return	14,908,250	8,828,913
Total	$ 24,866,860	$ 15,152,606
Cost Per Month	$ 2,072,238	$ 1,262,717
Demand Volume Units per Month	115,419	821,122
Demand Costs per MCF	$ 17.95	$ 1.54

UGI Gas Exhibit CEH-1R

OCA-I-42

Request:

Please provide reconnection fees received by class for the most recent 12-months available.

Response:

Please see Attachment OCA-I-42.

Prepared by or under the supervision of: Vivian K. Ressler

UGI Utilities, Inc. - Gas Division
Reconnection Fees by Rate Class
February 1, 2021 - January 31, 2022

	Total
Rate R	$ 1,314,284
Rate N	$ 26,748
Total	$ 1,341,032

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 11-R

Rebuttal Testimony of
John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed: **Weather Normalization Rider**
Residential Customer Charge

Dated: May 17, 2022

Table of Contents

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400 Hilton Head Island, SC 29926.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 11, on January 28, 2022.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to certain portions of the direct testimony submitted by other parties relating to the Company's proposed Weather Normalization Adjustment ("WNA") mechanism and impact on low-income customers resulting from the proposed Residential Customer Charge. The direct testimony of the other parties addressed are as follows:

- Bureau of Investigation and Enforcement ("I&E") Statement No. 4 - direct testimony of Ethan H. Cline ("I&E witness Cline");
- Office of Consumer Advocate ("OCA") Statement No. 4 - direct testimony of Roger D. Colton ("OCA witness Colton");
- Office of Consumer Advocate ("OCA") Statement No. 3 - direct testimony of Jerome D. Mierzwa ("OCA witness Mierzwa");
- The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Statement No. 1 – direct testimony of Harry S. Geller ("CAUSE-PA witness Geller"); and

- Office of Small Business Advocate ("OSBA") Statement No. 1 – direct testimony of Robert D. Knecht ("OSBA witness Knecht").

II. APPLICATION AND APPROPRIATENESS OF A DEADBAND

Q. Can you please provide a brief description of the use of the term "deadband" in the context of WNA riders?

A. A deadband sets a range in which the application of a WNA is not applied. If actual weather is different than normal weather, but the percentage difference between the actual heating degree days ("AHDD") and the normal heating degree days ("NHDD") is below the deadband threshold, then no WNA adjustment is applied. As such, some weather variability flows to customer bills and is seen in the associated utility distribution revenues.

Q. Please summarize the other parties' positions concerning the application of a deadband.

A. I&E witness Cline states that the WNA mechanism proposed by UGI Gas is different than that approved by the Pennsylvania Public Utility Commission ("Commission") for Columbia Gas of Pennsylvania, Inc. ("Columbia") since Columbia's WNA mechanism contains a three percent deadband. I&E witness Cline recommends that the UGI Gas WNA be approved if a three percent deadband is included.[1] Moreover, OCA witness Mierzwa states that the Commission should reject the proposed WNA mechanism, but if approved, it should include a 3 percent deadband. Specifically, he states, "If not rejected, there should be a 3% deadband included like the pilot WNA Rider utilized by Columbia Gas of

[1] I&E Statement No. 4 at 4-5.

Pennsylvania."[2] OCA Witness Mierzwa states that "a 3 percent deadband should be adopted to help ensure that the assessment of the WNA is limited to changes in usage attributable to variations in temperature."[3]

Q. Do you agree that the proposed WNA mechanism should only be approved with a three percent deadband?

A. No, I do not. Their recommendation to include a three percent deadband is misplaced and not fully supported with evidence. I&E witness Cline cites the Commission's decision in Columbia's 2020 base rate case at Docket No. R-2020-3018835, stating the Commission determined that "without an extraordinary set of circumstances, there is no need for Columbia to reconcile day-to-day temperature variations that are part of normal business."[4] UGI Gas's WNA mechanism does not reconcile weather on a day-to-day basis. Instead, it uses the difference between actual weather and normal weather across a full billing month time period, which includes, on average, approximately 30 days of weather. Further, Mr. Cline states, "Without the deadband customer rates could be subject to constant adjustment for normal weather variations in every billing cycle."[5] However, the proposed WNA mechanism only adjusts bills across the billing cycle during the months of October through May. Further, the primary intent of a WNA mechanism *is* to adjust for differences measured against normal weather. While these differences may sometimes be very small, so will the resulting impact on the customer's bill. However, it is essential to note that these adjustments will be consistent in application in all situations when actual weather

[2] OCA Statement No. 3 at 4.
[3] OCA Statement No. 3 at 54.
[4] Docket No. R-2020-5 3018835, Order entered February 19, 2021, pp. 264-265.
[5] I&E Statement No. 4 at 4.

varies from a defined normal heating degree day value. As indicated in my direct testimony, this approach is clearer and more understandable to customers than a deadband approach, which then injects an additional level of complexity for the Company's administration, training, and communication related to the WNA as well as to understanding the mechanics of WNA operation for customers. The Company's view is that establishing a WNA that is most clear and understandable to customers – with no deadband – is preferred to one that injects added complexity that would encumber customer education and understanding. For this reason, the Commission should reject the application of a deadband in approving the Company's WNA proposal.

Q. OCA Witness Mierzwa states that other weather variables impact the variations in usage. (OCA Statement No. 3 at 53-54.) Should a WNA mechanism, such as the one proposed by UGI Gas, adjust usage for these other variables?

A. No. Mr. Mierzwa states that other weather variables, such as variations due to average daily temperature, wind speed, and variations that can be introduced by using multiple weather stations for each delivery region, can impact usage.[6] He then concludes that a three percent deadband should be adopted to help ensure that the WNA is limited to changes in usage attributable to variations in temperature.[7] However, UGI Gas's base distribution rates and Commission-approved revenue levels are developed using normal temperature-based weather assumptions, and the proposed WNA mechanism adjusts customer bills for the difference between the actual weather and normal weather on the

[6] OCA Statement No. 3 at 53-54

[7] OCA Statement No. 3 at 53-54. Mr. Mierzwa claims that UGI Gas's WNA does not account for variations due to average daily temperature, wind speed, and variations that can be introduced by using multiple weather stations for each delivery region.

same temperature basis. While it is true that usage can be impacted by other weather factors such as humidity, wind speed, precipitation, cloud cover, etc., these factors have not been historically utilized to establish UGI Gas's base distribution rates. Temperature is the only weather variable utilized. Thus, the Company's approach in basing the operation of the WNA on temperature variation results in the WNA mechanism being established on the same temperature basis as UGI Gas's base distribution rates. The inclusion of a deadband to "ensure that the assessment of the WNA is limited to changes in usage attributable to variations in temperature"[8] is not necessary. The WNA adjusts the difference between normal weather and actual weather, measured by the difference between NHDDs and AHDDs. Introducing a deadband results in a mechanism that does not fully account for weather-related temperature variations. Moreover, other weather variables that Mr. Mierzwa calls out, such as wind speed, do not go away once a 3% level is exceeded. Thus, his argument that a 3% deadband is needed to "ensure that the assessment of the WNA is limited to changes in usage attributable to variations in temperature" is based on a false premise and should be given no weight.

Q. Are WNAs with a deadband as effective as WNAs without a deadband in accounting for variations in usage due to differences in normal and actual weather?

A. No. A three percent deadband means that a portion of revenue variation due to weather remains unaddressed. Thus, the goal of the WNA (i.e., to match customers' bills and revenue recovery with expected usage under normal temperature weather) is not fully realized. The deadband misrepresents the effect of temperature variations in weather. For

[8] OCA Statement No. 3 at 54.

example, under the application of a three percent deadband, if a billing cycle is 2.9 percent colder than normal, no adjustment will be made.

Q. Is Mr. Cline correct when he states that "UGI provided no evidence or support that would show how or why a departure from the Commission's previous ruling in Columbia regarding the deadband should not be followed" (I&E Statement No. 4 at 5)? [9]

A. No. On page 11 of my direct testimony (UGI Gas Statement No. 11), I explained why UGI Gas's proposed WNA mechanism did not include a deadband. Specifically, my direct testimony provided two primary rationales for not including a deadband: (1) the application of a deadband adds unnecessary complexity to the rider, which is a concern for customer communication and education; and (2) the WNA's intended goal is to stabilize billings and distribution revenues from readily identified weather-related variances, not just some of those variances.[10]

Q. Are there additional considerations the Commission should make with regard to the application of a deadband to the Company's WNA from a ratemaking policy perspective?

A. Yes, customers prefer the consistent application of rates and riders, and complexity can lower customer understanding and acceptance. One of Bonbright's '*Criteria of a Sound Rate Structure*' directly relates to this: "The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public

[9] I&E Statement No. 4 at 5.
[10] UGI Gas Statement No. 1 at 11.

acceptability, and feasibility of application."[11] Having a mechanism turn on and off based on a 0.1% difference in weather – between 3.0% and 3.1% – adds additional complexity and inconsistency that provides no improvements to the application of the mechanism and, therefore, should be avoided.

Q. Do all WNA and decoupling mechanisms contain deadbands?

A. No. As I stated in my direct testimony, research conducted in November 2021 indicated that approved and proposed decoupling mechanisms exist in 40 states in the U.S. and the District of Columbia.[12] While not all mechanisms were reviewed in detail, those in place for the utilities included in the Gas Group (the peer group) used to inform the Company's recommended Return on Equity were examined to gain insights into the use of deadbands. Out of the 26 utilities with a WNA or decoupling mechanism, only four rely on deadbands; thus, over 80% of WNA mechanisms currently in place do not have deadband requirements. Those with deadbands include: (1) Columbia at 3%; (2) South Jersey Gas Company at 0.5%; (3) Elizabethtown Gas Company at 0.5%; and (4) Spire Mississippi, Inc. which applies a dollar threshold based on the regulatory asset or liability (as the mechanism is not real-time focused). I also note that South Jersey and Elizabethtown Gas are affiliates and both subsidiaries of South Jersey Industries.

Q. How should the Commission weigh the arguments relating to including a deadband?

[11] Principles of Public Utility Rates, Second Edition, Page 384 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.
[12] UGI Gas Statement No. 11 at 19-20.

A. The Company believes a WNA mechanism without a deadband is best for customer understanding, as it results in the consistent and true application of the mechanism. While there is variation in the impact of weather on usage, those variations are what the WNA aims to remedy. Introducing a deadband moves away from reducing the variation in customer bills and the Company's distribution revenues due to weather. If the Commission seeks to introduce additional variability into the WNA mechanism by including a deadband, I recommend looking at Philadelphia Gas Works' ("PGW") WNA clause, which contains a 1% deadband,[13] to provide the least amount of weather-related variability to customer bills.

III. IMPACT ON LOW-INCOME CUSTOMERS

Q. What statements do OCA witnesses Mierzwa and Colton make regarding the impacts of the proposed WNA mechanism on low-income customers?

A. In the concluding remarks to Part 2, "Proposed Weather Normalization Adjustment Clause," of OCA witness Colton's direct testimony, he refers to a disproportionate adverse impact on low-income customers.[14] OCA witness Mierzwa cites OCA witness Mr. Roger Colton twice and states, "As discussed by OCA witness Mr. Roger Colton, the WNA will disproportionately and adversely affect low-income customers."[15]

Q. Are these statements supported by testimony provided by OCA witness Colton?

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[13] Philadelphia Gas Works Gas Service Tariff, Supplement No. 148 to Gas Service Tariff – Pa P.U.C. No 2, Weather Normalization Adjustment Clause, pp. 149-150.

[14] OCA Statement No. 4 at 15.

[15] OCA Statement No. 3 at 47-48. OCA uses this statement to respond to the Commission required Consideration 6 "Please explain how the WNA impacts customer incentives to employ efficiency measures and distributed energy resources" and Consideration 7, "Please explain how the WNA impacts low-income customers and support consumer assistance programs."

A. No. OCA witness Colton merely provides testimony on the benefits of budget billing, stating, "Budget Billing has the effect of being able to address the volatility in bill payment that arises as a result of variations in cold weather monthly heating bills. The Budget Billing program would play that role in a much more efficient and effective fashion than would the WNA."[16] He also suggests an expansion of the UGI Gas Low-Income Usage Reduction Program ("LIURP") to assist customers.[17] However, contrary to his statements and those of OCA Witness Mierzwa, the OCA provides no evidence of the "disproportionate adverse impact" of the proposed WNA mechanism on low-income customers. (OCA Statement No. 4 at 12.)

Q. Did the Company propose eliminating budget billing and only relying on the WNA mechanism to reduce bill volatility?

A. No. Budget billing is still an offering provided by UGI Gas and is not being proposed to be replaced by the WNA mechanism. Budget billing and a WNA mechanism are not mutually exclusive as both can exist and support customers by reducing bill volatility.

Q. Is budget billing a better way to protect low-income customers from bill volatility?

A. No. Budget billing provides a levelized monthly payment allowing a customer to spread annual bills calculated based on actual weather in relatively equal installments over 11 months, with the last month being a true-up month. Budget bills are recalculated every three months to ensure that the customer does not experience a substantial over or under-collection of revenue and require a larger end-of-year true-up. However, budget billing

[16] OCA Statement No. 4 at 14-15.
[17] OCA Statement No. 4 at 15.

does not address the difference between actual weather and normal weather, as the customer remains obligated for payments that ultimately reconcile to the actual weather billing amounts. Thus, budget billing is not comparable to WNA, which stabilizes the distribution charges of the bill regardless of weather variances and creates a more stable total bill on an annual basis. Moreover, customers certainly can elect to participate in, or remain in, the budget billing program after the WNA is implemented. With both WNA and budget billing, a customer can maximize bill stability and minimize month-to-month bill variances. After the WNA mechanism is approved, a customer on budget billing will see lower levels of change during these three-month reviews and lower annual reconciliations because the WNA will adjust winter heating season bills for the difference between actual and normal weather. Thus, the WNA would increase bill stability for these customers, which presumably is why they chose budget billing options in the first place. In summary, implementing the proposed WNA mechanism for customers on budget billing plans is beneficial for these customers who seek more bill stability.

Q. What conclusions are made by CAUSE-PA witness Geller with respect to the proposed WNA mechanism's impact on low-income customers?

A. CAUSE-PA witness Geller concludes that "UGI's proposed WNA shifts the risk of changing weather patterns from the utility to the consumer and prevents low-income customers from realizing bill savings due to warming trends."[18] Mr. Geller states, "Any risk of increased bills due to colder than normal winters is outweighed by the increasing

[18] CAUSE-PA Statement No. 1 at 5.

frequency of warmer winters."[19] As such, CAUSE-PA recommends that the Commission reject UGI Gas's proposed WNA mechanism.

Q. What evidence was provided by CAUSE-PA witness Geller that customer bills benefit more greatly from a higher frequency of warmer winters than colder winters?

A. CAUSE-PA witness Geller cites a discovery response provided by UGI Gas to OCA, which shows that over the last three years (2019, 2020, and 2021), the weather in UGI Gas's service territory was 3%, 9%, and 9% warmer than normal, respectively.[20]

Q. Are warmer-than-normal winters more common than colder-than-normal winters?

A. If the period of review is narrowly limited to the last three winters, then yes, warmer-than-normal winters are more common, as pointed out by CAUSE-PA. However, conclusions on the frequency of colder-than-normal and warmer-than-normal winters based on only three years of data are erroneous. For example, if you extend the review to winters from 2004-2021 – 18 years of data – the higher prevalence of winters is those that are colder-than-normal. Table 1 below shows that 10 of the last 18 winters were colder-than-normal.

[19] CAUSE-PA Statement No. 1 at 37.
[20] CAUSE-PA Statement No. 1 at 36 citing UGI Gas's response to OCA-VI-3.

Table 1 – 2004-2021 Heating Degree Days (October – May)

Fiscal Year	Actual HDD	Normal HDD	Variance to Normal HDD	
2004	5,640	5,439	4%	Colder
2005	5,791	5,439	6%	Colder
2006	5,256	5,439	3%	Warmer
2007	5,486	5,439	1%	Colder
2008	5,458	5,439	0%	Colder
2009	5,797	5,439	7%	Colder
2010	5,343	5,439	2%	Warmer
2011	5,796	5,439	7%	Colder
2012	4,614	5,439	15%	Warmer
2013	5,483	5,439	1%	Colder
2014	6,132	5,439	13%	Colder
2015	5,923	5,439	9%	Colder
2016	4,847	5,439	11%	Warmer
2017	4,913	5,439	10%	Warmer
2018	5,475	5,439	1%	Colder
2019	5,345	5,439	2%	Warmer
2020	4,990	5,439	8%	Warmer
2021	4,991	5,439	8%	Warmer
		Count	10	Colder
		Count	8	Warmer

Q. What insights are provided by the data presented in Table 1 when evaluating the appropriateness of UGI Gas's proposed WNA mechanism?

A. Some winters are colder-than-normal and some warmer-than-normal, but on average, the actual HDDs will be close to the normal HDDs across multiple years. This can be seen in the actual application of Columbia's WNA for the implementation years of 2013 through 2020; as presented in their 2020 base rate case filing and summarized in Table 2.[21]

[21] Columbia Gas of Pennsylvania, Inc. Docket Nos. R-2020-3018835 Direct M. J. Bell Statement No. 3 at 18. Accessible at https://www.puc.pa.gov/pcdocs/1661259.pdf.

Table 2 – 2013-2020 Columbia's WNA Net Adjustments

Columbia's Winter Seatson	Net WNA Adjustment (millions)
2013/2014 Season	-9.36
2014/2015 Season	-10.98
2015/2016 Season	11.52
2016/2017 Season	13.9
2017/2018 Season	-6.1
2018/2019 Season	-3.7
2019/2020 Season	2.45
2013 - 2020	-2.27

This illustrates a fundamental principle and benefit of WNA mechanisms; they work in a reciprocal manner; where customer bills are protected during colder-than-normal weather (2013/2014, 2014/2015, 2017/2018, 2018/2019) and utility revenues during warmer-than-normal weather (2015/2016, 2016/2017, 2019/2020). Yet, they on average over time result in symmetry and neutrality between customers costs and revenue collection.

Q. Is there additional evidence that should be weighed in considering the trade-offs for customers between colder than normal or warmer than normal winters?

A. Yes, the function of the WNA mechanism is not to transfer risk or set up a mechanism that benefits the utility more often than its customers. Weather is not normal every year, so the rates developed using normal weather result in differences between the expected customer bills and UGI Gas revenues and the actual customer bills and UGI Gas revenues. As stated in my direct testimony, Commission Chairman Gladys Brown Dutrieuille has stated that "[t]he Weather Normalization Adjustment works bi-directionally to insulate customers from high bills during the extremely cold months, while also limiting the decline in revenue for [the utility] during unseasonably warm heating months."[22] She also "encourage[d] other natural gas distribution companies in the Commonwealth to consider utilization of weather decoupling distribution charge mechanisms."[23]

Q. What is the impact on low-income customers enrolled in the Company's Customer Assistance Program ("CAP") if the Commission approves the proposed WNA mechanism?

A. Under the proposed WNA mechanism, CAP customers who pay an "average bill" amount will see lower bill variability for distribution costs. This is due to the calculation of their average bill reflecting the implementation of the WNA mechanism; which reduces actual bill variability that would otherwise impact the "average bill" calculation due to non-normal weather. CAP customers who are currently paying a percent-of-income based bill will see no impact. UGI Gas reviews CAP customers quarterly to ascertain if the average bill or the percent-of-income results in the lowest bill and, as necessary, migrates customers to their most beneficial option. The proposed WNA mechanism increases average bill stability, decreasing customers' movement between average bill and percent-of-income during these quarterly reviews. Ultimately this increases bill stability for all CAP customers.

[22] *Pa. PUC v. Columbia Gas of Pa., Inc.*, Docket Nos. R-2018-2647577, *et al.* (Statement of Chairman Brown Dutrieuille dated Dec. 6, 2018).
[23] *Id.*

IV. RESPONSE TO OCA'S CRITIQUE OF THE WNA MECHANISM

Q. Outside of the conclusory statements relating to the impact on low-income customers, does the OCA provide additional testimony on the proposed WNA mechanism?

A. Yes. OCA witness Mierzwa provides several critiques of the proposed mechanism, ultimately recommending that the Commission reject the proposal or, if approved, include a deadband. OCA witness Mierzwa's critique and proposed denial of the WNA are based on the following reasons:

- The proposed WNA mechanism embodies a take-or-pay pricing policy.
- The proposed WNA mechanism inappropriately adjusts rates without considering other changes in total revenues and costs.
- The proposed WNA mechanism is biased to the Company's benefit during colder-than-normal billing periods.
- UGI Gas has not demonstrated that its current system of rates and charges result in inadequate revenue stability, and does not decrease the frequency of rate case filings by UGI Gas."[24]

Q. Why does OCA Witness Mierzwa believe the WNA mechanism results in a take-or-pay billing feature?

A. Mr. Mierzwa believes that "[u]nder the proposed WNA mechanism, consumers would pay for distribution service they do and do not receive," so "[n]o matter how much distribution service is actually purchased by UGI Gas's Residential customers, ultimately, under the proposed WNA mechanism, those customers would pay for a normalized level of service whether they take delivery or not."[25] He then concludes the WNA converts "a volumetric rate into rates that yield a given revenue, regardless of the amount of service purchased," which he believes "converts the Company's volumetric rate into a take-or-pay billing

[24] OCA Statement No. 3 at 50.
[25] OCA Statement No. 3 at 50.

feature."[26] Under Mr. Mierzwa's perspective, minimum bills, customer charges, and demand charges would all represent take-or-pay billing features. These are all accepted rate structures used across North America and within Pennsylvania. Mr. Mierzwa errs in his conclusions that the level of distribution service received is related to the amount of volumetric usage paid for by customers.

Q. Does the amount of distribution service provided to customers change with the weather and with the total volumetric charges paid for by customers for this distribution service?

A. No. Contrary to Mr. Mierzwa's perspective, while customers pay more as they consume more natural gas (the commodity), they are not provided with additional distribution services as they consume more, nor do they receive less distribution services when they consume less. UGI Gas's distribution rates are used to recover UGI Gas's approved revenue requirement associated with UGI Gas's distribution system that stands ready to provide service to customers. While UGI's cost structure is largely fixed and does not vary with the amount of gas consumed by customers; the rates for recovery of these fixed costs are set on a volumetric basis as part of currently approved rate design. Volumetric rates match customers' contributions to these fixed costs via rate calculations that assume normal weather. When the weather is colder than normal, UGI Gas's customers use more gas (the commodity) but do not purchase more distribution service. They do not get more metering, capacity, main footage, service lines, billing, and customer service; they get the same level of distribution service. When the weather is warmer than normal, UGI Gas's

[26] OCA Statement No. 3 at 51.

customers use less gas (the commodity), but they do not purchase less distribution services. Under UGI Gas's current rate structures, customers will be billed more when it is colder-than-normal and less when it is warmer-than-normal, but there will be no change in the amount of distribution service provided to these customers.

Q. What is a take-or-pay billing feature, and does the WNA mechanism result in a take-or-pay billing feature?

A. A take-or-pay billing feature or contract feature is when a supplier of a product requires the customer to take a certain portion of the product, and if the customer does not take that portion, then the customer still pays some amount to the supplier (for the unused portion). UGI Gas's proposed WNA mechanism and the WNA mechanism in place for Columbia, PGW, and dozens of other utilities do not represent a take-or-pay billing feature. Nor do customer charges, demand charges, or minimum bills represent take-or-pay billing features. All of these rate structures and the proposed WNA mechanism are used to match the nature of the service being provided; that it is fixed and does not vary with usage, to the recovery of these costs form customers. In contrast to the OCA's mischaracterization, the WNA mechanism recognizes that the level of distribution service provided does not vary with weather and is paid for more consistently under a WNA regardless of whether a customer's gas usage increases or decreases due to colder or warmer than normal weather. Take-or-pay contracts are used to ensure the customer bears the full quantity risk if the customer's demand is lower than expected, moving this risk from supplier to customer. In contrast, the WNA mechanism creates symmetry between the customers and UGI Gas, where customers are protected from high bills during colder winter months while limiting the decline in UGI Gas's revenue during warm winter months. It is not a transfer of risk but rather a symmetry: using normal weather set the level of rates and ensuring customer bills and revenues reflect normal weather. Lastly, using Mr. Mierzwa's perspective, that the amount of distribution service provided varies with weather, a WNA is equally as much a "take-and-not-pay" construct as it would be a "take-or-pay" construct. Thus, Mr. Mierzwa's "take-or-pay" argument is both incorrect in application to a WNA and one-sided in an effort to distort the factual operation of the WNA.

Q. OCA witness Mierzwa concludes that the proposed WNA mechanism automatically adjusts revenues between rate cases without considering other changes in total revenues and costs.[27] Is this a reasonable critique of WNA mechanisms?

A. No, it is misplaced. The appropriate level of revenues and customer bills are set as a result of rate cases, and the proposed WNA mechanism adjusts actual revenues and customer bills to account for the difference between normal weather and actual weather, in order to better align what occurs in future years with what was set during the rate case. A mechanism that adjusts both costs and revenues between rate cases is a formula rate plan, and these mechanisms impact the normalized revenue allowed for recovery by the utility from their customers. The proposed WNA mechanism is not of this type. It only limits the variations between normal weather and actual weather on customers' bills and the utility's distribution revenues. It does not set a new level of allowed revenues.

[27] OCA Statement No. 3 at 50-51.

Q. Mr. Mierzwa asserts that a gas utility's "O&M expenses would tend to increase as demand increase under colder-than-normal weather and tend to decline as demand decreases under warmer-than-normal weather."[28] What evidence is provided to support this conjecture?

A. The OCA provides no evidence of this relationship or the magnitude of weather's influence on a gas distribution utility's level of O&M expenses. The fact remains that UGI Gas's recoverable annual revenue requirement is set during base rate proceedings and is not subject true-ups or adjustments based on the O&M requirements of each month of the year. UGI Gas's recoverable annual revenue requirement is set to be recovered through volumetric rates under the assumption of normal weather. The proposed WNA mechanism finishes this logic; whereby actual revenues collected reflect normal weather; reducing the risks of differences between actual and normal weather for both UGI Gas and its customers.

Q. What calculation does OCA witness Mierzwa present to support his claim that the WNA is biased to the Company's benefit during colder-than-normal billing periods?

A. Mr. Mierzwa presents a hypothetical weather normalization adjustment for a utility customer under two different assumed levels of temperature sensitivity. One with a hypothetical temperature-sensitive usage at 0.02 Mcf per HDD and another with temperature-sensitive usage at 0.025 Mcf per HDD. Using these assumptions, he arrives at two different weather normalized billing volumes: (1) 22 Mcf under the 0.025 Mcf per HDD assumption; and (2) 18 Mcf under the 0.02 Mcf per HDD assumption. He then

[28] OCA Statement No. 3 at 51.

concludes that this difference results in a benefit to the Company during colder-than-normal billing periods.

Q. What is the underlying assumption used to develop Mr. Mierzwa's hypothetical adjustment, and is this a reasonable assumption to rely upon?

A. Mr. Mierzwa relies on his assumption that "[t]he usage of customers per HDD increases as HDD increase."[29] However, the relationship between HDDs and temperature-sensitive usage is more nuanced than Mr. Mierzwa's depiction and as such, his oversimplified assumption should not be relied upon. Over certain months across certain temperatures, there may be an increase in temperature-sensitive usage per HDD as HDDs rise. Still, for other months across different temperatures, there may be no increase in temperature-sensitive usage per HDD as temperatures rise. Typically, during the first cold snap, customers respond by setting thermostats at higher heating set points. Therefore, the first high level of HDDs during the season can have a higher use per HDD. As the winter progresses, customers tend to adjust their thermostats to a more even level of heating, so that the coldest months see more stable temperature-sensitive usage per HDD. In some instances, schools and businesses close during extremely cold weather, and their consumption drops significantly; resulting in negative relationship between temperature-sensitive usage per HDD and increases in HDDs.

Q. Has UGI Gas analyzed how customers' temperature sensitive usage changes as HDDs increase?

[29] OCA Statement No. 3 at 53.

A. Yes. Over the last three years UGI Gas's residential customers' temperature sensitive usage per a HDD is 0.0136 mcf per HDD across the coldest months of January and February; those closest aligned with Mr. Mierzwa's hypothetical example. Based on regression results from the last 15 years of data, a 25 percent increase in heating degree days would result in only a 1% increase in temperature sensitive usage per a HDD; moving from 0.0136 mcf per HDD to 0.0137 mcf per HDD. This is in stark contrast with the hypothetical example provided by Mr. Mierzwa. First, Mr. Mierzwa uses a temperature-sensitive usage at 0.02 Mcf per HDD; 47% higher than the actual temperature sensitive usage per a HDD of 0.0136 Mcf. Second, Mr. Mierzwa's hypothetical comparison shows a 25% increase in temperature sensitive usage per a HDD; moving from 0.020 to 0.025 Mcf per HDD; vastly different than the 1% difference supported by the actual review of UGI Gas's customer behavior. Mr. Mierzwa's hypothetical example is far from reality and should not be relied upon to inform an opinion on the appropriateness of the proposed WNA mechanism.

Q. Have you updated OCA witness Mierzwa's hypothetical example with this actual data?

A. Yes. I relied on the same calculations presented by Mr. Mierzwa but replaced his two hypothetical temperature sensitive usage per a HDD of 0.02 Mcf and 0.025 with the actual data of 0.0136 Mcf and 0.0137. Using the same assumed HDDs of 800 and 1,000 as relied upon by Mr. Mierzwa results in no change to the Weather Normalized Billing Ccfs. A customer with a temperature sensitive usage per a HDD of 0.0136 Mcf under a 800 HDD month and with a temperature sensitive usage per a HDD of 0.0137 Mcf under a 1000 HDD would have the same level of Weather Normalized Billing Ccfs. In other words, the impact of reflecting more realistic assumption based on UGI Gas's actual data shows that Mr. Mierzwa's conclusion that the WNA is biased in the Company's favor when weather is colder-than-normal is unfounded.

Q. Has Mr. Mierzwa provided evidence to support his speculation that the Base Load Monthly Ccfs ("BLMC") "of Residential customers could have changed significantly as a result of the pandemic and customers could be assessed charges for these changes in usage."[30]?

A. Mr. Mierzwa did not provide any evidence to support this claim. However, UGI Gas collected this information, presented in Table 3 below. This table shows the trend in the Daily Baseload Usage per Customer over the last 16 years for residential customers. The last two columns of this table provide the annual change for the 3-year average and 1 year average. The 3-year annual change and 1-year annual change from 2019 to 2020 was 0.000 and 0.003, respectively. For 2020-2021 the 3-year annual change and 1-year annual change was 0.001 and 0.000 The majority of pre-pandemic years contain annual changes that are higher than those occurring between 2019 and 2020.

[30] OCA Statement No. 3 at 53.

Table 3 – 2006- 2021 Daily Baseload Usage per Customer (June – August)

	Length of Period		Annual Change	
	3 Year Avg	1 Year Avg	3 Year Avg	1 Year Avg
Sep-06	0.054	0.053		
Sep-07	0.052	0.052	(0.002)	(0.001)
Sep-08	0.052	0.051	(0.000)	(0.001)
Sep-09	0.052	0.053	0.000	0.002
Sep-10	0.051	0.049	(0.001)	(0.004)
Sep-11	0.052	0.053	0.001	0.003
Sep-12	0.050	0.049	(0.001)	(0.004)
Sep-13	0.052	0.054	0.002	0.006
Sep-14	0.050	0.048	(0.001)	(0.006)
Sep-15	0.052	0.054	0.002	0.006
Sep-16	0.051	0.051	(0.001)	(0.003)
Sep-17	0.051	0.047	(0.000)	(0.004)
Sep-18	0.048	0.044	(0.003)	(0.003)
Sep-19	0.045	0.045	(0.002)	0.000
Sep-20	0.045	0.047	0.000	0.003
Sep-21	0.046	0.047	0.001	(0.000)

Q. Does the evidence provided in Table 3 above show significant changes in Daily Baseload Usage per Customer in recent years?

A. The tables indicate that the Daily Baseload Usage per Customer varies every year, and the three-year average provides a smoothing effect on this annual variance. Further, the change from a pre-pandemic three-year average Daily Baseload Usage per Customer of 0.045 Mcf to a current three-year average of 0.046 Mcf is not a "significant change," as Mr. Mierzwa speculates, and is far below the changes that have occurred annually over the last sixteen years.

Q. In your direct testimony, you address each of the 14 considerations outlined in the Commission's Statements of Policy on alternative ratemaking.[31] Does OCA witness Mierzwa also address these 14 considerations?

A. Yes. OCA witness Mierzwa provides the OCA's position on each of the responses to the 14 Considerations contained in my direct testimony. There are a few items worth noting in the OCA's responses to these Considerations. OCA's responses to Considerations 1, 8, and 9 state that the WNA mechanism is biased in the Company's favor during colder-than-normal months. As I explained previously, Mr. Mierzwa's claim of alleged bias is unfounded and, therefore, the OCA's responses to Considerations 1, 8, and 9 should be disregarded. For Considerations 2 through 5 and 11, the OCA either agrees with UGI Gas's comments or provides clarifications to ensure completeness; however, these are not sources of disagreement. OCA's responses to Considerations 6 and 7 point to the testimony of OCA witness Colton purportedly showing that the WNA will disproportionately and adversely affect low-income customers. This critique is also addressed above in my testimony, where I show that Mr. Colton only provides testimony on the benefits of budget billing but no evidence to support conclusions that the WNA will adversely affect low-income customers. After reviewing these Considerations, we are left with Considerations 10, 12, 13, and 14- for additional response.

For Consideration 10, the OCA states, "A reduction to the frequency of rate case filings would be a benefit of an alternative ratemaking mechanism. The WNA does not provide this benefit."[32] There is no standard or requirement that utilities must reduce the frequency of rate case filing to receive approval of a WNA. Neither Columbia nor PGW

[31] 52 Pa. Code § 69.3302.
[32] OCA Statement No. 3 at 48.

had this standard applied to them when they received approval for their WNAs. Moreover, not all alternative ratemaking proposals can impact every consideration; the mechanisms approved by the Commission for Columbia and PGW also do not have an impact on regulatory lag. Finally, as an alternative ratemaking proposal, WNA is not a mechanism which is intended to reduce the frequency of rate case filings. Comparably, an alternative ratemaking proposal which would propose, say, full formula rates, could possibly reduce the frequency of rate case filings. As I noted above, UGI Gas has not made that type of proposal in this proceeding.

For Consideration 12, the OCA states, "The WNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony."[33] The WNA mechanism insulates customers from high bills during colder-than-normal months, while also limiting a decline in distribution revenues for UGI Gas during warmer-than-normal months. In particular, WNA bills will be otherwise lower than non-WNA bills during colder than normal periods. These cold periods are the most sensitive to customers since they stand to create the largest burden to customers. Thus, inherent in the application of a WNA is this "consumer protection" against the burdens cold weather bills can produce. There are no further consumer protections required, as this is a balance in risk and reward sharing between UGI Gas and UGI Gas's customers.

For Consideration 13, the OCA states, "UGI has not provided any evidence to indicate that the WNA will be understandable to customers."[34] UGI Gas's proposed WNA mechanism is similar to that implemented by Columbia, PGW, and other utilities across the United States. UGI Gas's proposed WNA mechanism adjusts current billings on a

[33] OCA Statement No. 3 at 49.
[34] OCA Statement No. 3 at 50.

monthly billing basis as the bill is being calculated and issued, helping with customer understanding. Additional details on customer education efforts and approaches are provided in Section V below in this testimony.

Lastly, for Consideration 14, the OCA states, "The WNA does not provide an incentive to increase the safety and reliability of the UGI Gas System." As stated in my direct testimony, the proposed WNA will help minimize the volatility of the recovery of UGI Gas's cost of service, inclusive of investments and costs to continue enhancing the safety and reliability of its system. The stabilization of cash flows allows a utility to focus more acutely on operational items under its direct control, as Chairman Gladys Brown Dutrieuille determined upon review of Columbia's WNA, when she stated, "This decoupling of uncontrollable weather from revenues stabilizes Columbia's cashflow, and in turn, allows Columbia to more acutely focus on operational items within its control; namely infrastructure upgrades and repairs."[35]

Q. Is the Company and OCA in agreement that the proposed WNA does not negatively impact energy efficiency programs?

A. It appears so. The OCA's response to Consideration 5: Please explain how the WNA limits or eliminates 9 disincentives for the promotion of efficiency programs was, "OCA: The WNA does not limit or eliminate incentives for the promotion of efficiency programs."[36] UGI Gas's response in my direct testimony was the following: "The proposed WNA only addresses variations due to weather. The WNA does not negatively impact energy efficiency programs.

[35] *Pa. PUC v. Columbia Gas of Pa., Inc.*, Docket Nos. R-2018-2647577, *et al.* (Statement of Chairman Brown Dutrieuille dated Dec. 6, 2018).
[36] OCA Statement No. 3 at 47.

Moreover, UGI Gas maintains a robust Energy Efficiency & Conservation ("EE&C") program, which it has voluntarily implemented for its customers and will use to continue promoting energy efficiency measures."[37] The benefit of the Company's proposed WNA mechanism is that Customers will continue to benefit from their energy conservation efforts, as the actual usage on each customer's bill is utilized to calculate the WNA adjustment, and that usage level will reflect the conservation behaviors of each customer.

V. CUSTOMER EDUCATION AND OUTREACH

Q. What plans does the Company have to help facilitate customer understanding and acceptance of the WNA mechanism?

A. The Company is working to develop a communication plan designed to educate customers about the WNA mechanism. Upon approval of WNA, and subject to final WNA design, the Company will finalize these plans. The Company will also provide notice to customers as was noted in response (a)(10) of the Section 53.52 Filing Requirements as found in UGI Gas Book I of this rate case proceeding. In addition to the notification of WNA approval, the Company plans to provide a billing insert with WNA FAQs that will also be posted to and available on the Company's website. The Company is also planning on including an article on WNA in its customer newsletter following the approval of the WNA. Changes are also planned to be made to the printed bill the customers receive. When a WNA is applied to a bill, it will appear as a separate line item within the current charges section of a bill and an additional message on the bottom of the bill will indicate that the bill has been adjusted to reduce the impact of either colder or warmer than normal weather. An

[37] UGI Gas Statement No. 11 at 16.

additional term will be added to the back of bill to provide a plain-language definition of the WNA. Preparations are also under to way to ensure that all call center representatives are trained on the WNA and have the necessary tools available to them to walk a customer through how a WNA amount on a bill was calculated. Following implementation of the WNA mechanism and planned communication activities, the Company will continue to monitor customer feedback, and modify its communication plan accordingly to best support the needs of customers in their understanding of the WNA mechanism.

VI. RESPONSE TO OSBA POSITION

Q. What conclusions does OSBA witness Knecht make with respect to the proposed WNA mechanisms?

A. OSBA witness Knecht states, "I am advised by counsel that OSBA intends to contest this proposal as not just and reasonable on the grounds that the substantial risk reduction benefits to the Company and the rate instability implications for customers associated with this mechanism are not reasonably reflected in the allowed return on capital claim in this proceeding."[38]

Q. What is your response to the position presented by the OSBA?

A. First, a point of clarification, the sentence quoted above in OSBA witness Knecht's testimony contains the statement, "...the rate instability implications for customers associated with this mechanism…" This statement is incorrect as the WNA mechanism increases bill stability by removing the impact of total usage due to weather and does not

[38] OSBA Statement No. 1 at 24.

change the rates charged. As stated in my direct testimony and supported by Company witness Paul R. Moul, "the utilities included in his Gas Group (the peer group) already have tariff mechanisms for stabilization of revenues due to variation in weather, either through similar WNA mechanisms as that proposed by UGI Gas or through full revenue decoupling mechanisms."[39]

VII. PROPOSED RESIDENTIAL CUSTOMER CHARGE

Q. How is the issue of gradualism related to the appropriateness of the monthly residential customer charge level?

A. OCA witness Mierzwa would like us to believe that the only charge for gas service is the customer charge and that an increase of $14.60 to $19.95 – representing a 37 percent increase is out of alignment with gradualism.[40] When looking at concepts of gradualism, it is necessary to review the entire bill of a customer not just a single component because customers pay their entire bill, not only single rate components. Only customers with zero usage would see a 37% difference between a customer charge of $14.60 and $19.95; most customers would see a much lower difference given any revenues not recovered in the customer charge must be recovered in the volumetric energy charge. Mr. Mierzwa is recommending a customer charge of $16.00. Moving the customer charge from $19.95 to $16.00 will result in a corresponding increase in the variable per Mcf distribution charge; in this instance, moving the proposed Mcf charge of $4.9996 (with $19.95) to $5.5612 (with $16.00). A customer who only uses 3 Mcf a month would only see a $2.27 difference

[39] UGI Gas Statement No. 11 at 20-21.
[40] OCA Statement No. 3 at 35.

in their bill under the $19.95 customer charge, representing a 6.93% difference, which meets the threshold of gradualism for this low use customer.

Q. How do you respond to OCA witness Mierzwa's claim that a lower customer charge is more consistent with energy conservation and efficiency goals?

A. Mr. Mierzwa provides no basis or support for his conclusion. He makes claims based on price elasticity (how consumers respond to changes in prices) with no basis as to why he believes they will respond in the manner he believes nor why his preferred response is best. In their discussions, these arguments suffer from an unreasonably narrow definition of conservation and look to value only this singular consideration in rate design recommendations. Secondly, Mr. Mierzwa overgeneralizes his premises when reaching conclusions. Mr. Mierzwa's premise is that a higher percentage of cost recovery in a fixed charge leads to less conservation, and thus the increase in a customer charge will result in less conservation. In short, he introduces two overgeneralizations: (1) he assumes the only reason for conservation is price signals, and (2) he assumes that customers will respond to a change of this degree (i.e., a change of $5.35 monthly) without consideration of total bill impact.

Q. What definition of conservation should be utilized in the context of setting distribution rates?

A. Conservation is the act of preserving, guarding, and protecting wise use. In this case, it is the wise use of distribution facility resources. The issue under consideration is much broader than simply a concept of reducing usage; where numerous principles and considerations must be made as to the correct level of fixed monthly customer charge. Certain costs of operating a distribution utility are incurred regardless of the level of gas consumed; they are incurred simply to attach a customer and meet their peak demands. By charging customers on a variable basis for these fixed costs, customers can spend time and resources on reducing their bills; however, this does not reduce the costs incurred by the utility. This is not an efficient use of our resources as a society. Although the consumer spent time and resources to "save" money, it does not reduce the costs incurred by the utility to provide service, *i.e.*, any bill savings under a lower customer charge would exceed the actual savings of the resources used to provide service. Those costs are simply charged to some other customer or reduce the earnings of the utility. This is a zero-sum game; the gain to one customer by reducing how much they pay for fixed costs is the loss of either another customer or the utility itself.

Q. How do utility consumers respond to price signals and changes in rates?

A. They respond in very complicated and inconsistent ways. First, any reduction in usage is not just a function of price signals. Energy efficiency gains and reduction in usage to date are based on a several items, including, but not limited to, capital investment in appliances (partially due to rebate and tax policies and federal efficiency mandates), the thermal envelope of housing, fuel switching, and other societal/cultural responses that will not go away with the customer charge increase. Second, the conclusion that a change from $14.60 to $19.95 will reduce consumers' desire to reduce usage is based on an incorrect interpretation of price elasticity. Utility customers have mixed abilities to respond to prices based on numerous contributing factors, including heating fuel, ambient temperatures, alternative fuel options, family size, access to capital, etc. They also have mixed desires to respond to prices, given that they face plenty of competing concerns and may choose not to spend time and effort on managing their energy use. A paper by the Electric Power Research Institute ("EPRI") provides clarifying insight into the complexity of price elasticity for utility service.

> Consumers may be practically capable of responding to price changes, but do not do so for a number of reasons. First and most importantly, as demonstrated above, the lack of exhibited price response could be because the consumer has not been subject to a price change that exceeds its price threshold. Electricity price changes are generally limited to single digit amounts at any one time to protect consumers from the consequences. As a result, the price changes that are implemented do not meet the response threshold requirement. But, when faced with a large price change, they may indeed exhibit a response because it exceeds the threshold.[41]

This quote clearly states that single digit price changes may not reach the response threshold to elicit changes in usage. EPRI states why this would be the case for some consumers.

> Additionally, many consumers may treat electricity as a necessity, for which there is no apparent substitute, at least in the near-term. Therefore their consumption is driven primarily by other factors, such as income, weather, and lifestyle. Still others may simply be unwilling to devote time and effort to managing electricity usage closely, even though they are aware that opportunities to respond are available and that the net savings are tangible. Others may pay so little attention to electricity consumption and bills that they do not realize that a price change has occurred.[42]

Q. Do you agree with OCA witness Colton's determination that the proposed customer charge, "disproportionately and adversely affects low-income customers"?[43]

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[41] Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis*, p. 14.
[42] Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis,* p. 14.
[43] OCA Statement No. 4 at 6.

A. No. For the reasons explained in response to OCA witness Mierzwa, Mr. Colton's argument that the proposed increase in the customer charge will discourage energy efficiency and conservation is without merit. Moreover, the Company's proposal lowers the average bill for low income and CAP customers.

Q. Have you analyzed the difference between the OCA recommended $16.00 monthly residential customer charge and the Company's proposed $19.95 a month charge on low-income customers?

A. Yes, I have. For illustrative purposes, I have used two scenarios: (1) the OCA recommended customer charge of $16.00[44]; and (2) the Company's proposed residential customer charge of $19.95. Moving the customer charge from $19.95 to $16.00 at proposed rates will result in a corresponding increase to the variable per Mcf distribution charge. For example, assuming the Company's proposed residential revenue target, a customer charge of $19.95 will result in a distribution charge of charge of $4.9996 as opposed to the $5.5612 under a $16.00 monthly customer charge. Table 4 below provides monthly and annual bill differences between the two alternative customer charges. This table shows an annual decrease of $11.63 for the average CAP customer and an annual decrease of $10.38 for the average low-income customer.

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[44] OCA Statement No. 3 at 38.

Table 4 – Annual Bill Impact of Customer Charge

CAP Participant Usage					
		Total Monthly Bill		Difference	
Month	Monthly Usage	$16.00	$19.95	Total	Percentage
OCT-20	7.43	$57.31	$57.09	($0.22)	0%
NOV-20	13.75	$92.49	$88.72	($3.77)	-4%
DEC-20	19.15	$122.52	$115.71	($6.81)	-6%
JAN-21	20.74	$131.33	$123.63	($7.70)	-6%
FEB-21	17.45	$113.07	$107.21	($5.85)	-5%
MAR-21	10.01	$71.66	$69.99	($1.67)	-2%
APR-21	5.97	$49.20	$49.80	$0.60	1%
MAY-21	3.08	$33.10	$35.33	$2.22	7%
JUN-21	1.87	$26.41	$29.31	$2.90	11%
JUL-21	1.67	$25.31	$28.32	$3.01	12%
AUG-21	1.72	$25.58	$28.56	$2.98	12%
SEP-21	2.26	$28.57	$31.25	$2.68	9%
Total	**105.11**	**$776.55**	**$764.92**	**($11.63)**	**-1%**

Low-Income Customer Usage					
		Total Monthly Bill		Difference	
Month	Monthly Usage	$16.00	$19.95	Total	Percentage
OCT-20	7.26	$56.38	$56.26	($0.13)	0%
NOV-20	13.47	$90.91	$87.29	($3.61)	-4%
DEC-20	18.78	$120.45	$113.85	($6.60)	-5%
JAN-21	20.35	$129.17	$121.69	($7.48)	-6%
FEB-21	17.15	$111.37	$105.69	($5.68)	-5%
MAR-21	9.77	$70.31	$68.77	($1.53)	-2%
APR-21	5.78	$48.16	$48.86	$0.70	1%
MAY-21	3.02	$32.80	$35.05	$2.25	7%
JUN-21	1.80	$26.01	$28.95	$2.94	11%
JUL-21	1.63	$25.04	$28.08	$3.04	12%
AUG-21	1.68	$25.36	$28.37	$3.00	12%
SEP-21	2.20	$28.23	$30.95	$2.71	10%
Total	**102.89**	**$764.19**	**$753.81**	**($10.38)**	**-1%**

Thus, OCA's concerns about the impact of the Company's proposed customer charge are misplaced.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 12-R

Rebuttal Testimony of
Daniel V. Adamo

Topics Addressed:	**Universal Service Programs**
	Impact of the Company's Proposals on Low-Income Customers
	Economic Impact of COVID-19 on Low-Income Customers

Dated: May 17, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Daniel V. Adamo. My current business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. By whom and in what capacity are you employed?

A. I am employed by UGI Utilities, Inc. (“UGI”), as Vice President – Customer Relations. UGI is a wholly-owned subsidiary of UGI Corporation (“UGI Corp.”). UGI has two operating divisions, the Gas Division (“UGI Gas” or the “Company”) and the Electric Division (“UGI Electric”), each of which is a public utility regulated by the Pennsylvania Public Utility Commission (“Commission” or “PUC”).

Q. Please briefly describe your responsibilities in that capacity.

A. In this position, I am responsible for managing all marketing, sales, community relations, communications, and the customer information center for UGI, as well as the customer accounting, credit and collections, customer outreach, and compliance departments. In this role, I oversee regulatory compliance with Chapter 14 of the Public Utility Code, 66 Pa. C.S. §§ 1401, *et seq.*, related consumer regulations, including Chapter 56 of the Pennsylvania Code, 52 Pa. Code § 56.1, et seq., and compliance with generally applicable consumer protection, collection, consumer bankruptcy regulations, and the administration of all Universal Service Programs.

Q. What is your educational and professional background?

A. I graduated from Lehigh University in 1998 with a B.S. in Mechanical Engineering. I started my employment with UGI in 1998. My full resume is attached as UGI Gas Exhibit DVA-1R.

Q. Have you been involved in other proceedings before the Commission?

A. Yes. I testified on behalf of UGI Gas in its purchased gas cost filings in 2008 and 2009 as well as the Company's petition for approval of the Growth Extension Tariff ("GET Gas") Program in 2013. I also testified on behalf of UGI Gas in its 2019 Base Rate Case proceeding at Docket No. R-2018-3006814 and its 2020 Base Rate Case proceeding at Docket No. R-2019-3015162. Further, I testified on behalf of UGI Electric in its 2021 Base Rate Case proceeding at Docket No. R-2021-3023618. Please see UGI Exhibit DVA-1R for a complete listing of the proceedings in which I testified and their docket numbers.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Gas?

A. No, I did not.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes, I am sponsoring UGI Gas Exhibit Nos. DVA-1R through DVA-6R.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony of other party witnesses regarding: (1) the programs offered under the Company's Universal Service and Energy Conservation

Plan ("USECP"); (2) the impact of the Company's proposals in this proceeding on low-income customers; and (3) the economic impact of coronavirus disease 2019 ("COVID-19") on low-income customers, and the Company's efforts in response thereto.

Specifically, I respond to portions of the direct testimony of Roger D. Colton, submitted on behalf of the Office of Consumer Advocate ("OCA") (OCA St. No. 4), the direct testimony of Harry S. Geller, submitted on behalf of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") (CAUSE-PA St. No. 1), and the direct testimony of Eugene M. Brady, submitted on behalf of the Commission on Economic Opportunity ("CEO") (CEO St. No. 1).

II. UGI GAS HAS SHOWN ITS COMMITMENT TO HELPING ITS CUSTOMERS WHILE MAINTAINING A HIGH LEVEL OF CUSTOMER SERVICE

Q. Please describe UGI Gas's approach to providing support to its customers.

A. UGI Gas is committed to providing support to all of its customers, and particularly to customers experiencing a financial hardship. The Company does this through a variety of programs and voluntary initiatives, and it has made tremendous strides in recent years in the number of low-income and payment troubled customers that it has been able to assist. Although there is always room for improvement, the Company has continued to improve its processes, and works collaboratively with low-income advocates to identify the changing needs impacting its service territory. One example that shows the Company's commitment to helping its customers was in its response to COVID-19.

Q. Please describe the Company's response to COVID-19.

A. UGI Gas quickly recognized that all customer classes would be impacted from the COVID-19 pandemic. As described in the direct testimony of Christopher R. Brown (UGI Gas St. No. 1), the Company developed comprehensive communications plans for reaching customers to inform and educate them about programs and Company actions. Further, the Company ceased service terminations on March 13, 2020, stopped removing customers from its Customer Assistance Program ("CAP") for failure to recertify on March 18, 2020, and voluntarily began waiving all late payment charges on March 24, 2020. The Company increased its Operation Share donations by $500,000 per year beginning FY19, expanded eligibility under its Operation Share grant program to 250% of the federal poverty limit ("FPL"), and increased the maximum grant size from $400 to $600. Finally, the Company implemented a matching program for employee donations to food banks and donated more than $450,000 to local food banks.

Q. What programs did the Company implement in its last base rate case to respond to COVID-19?

A. As part of its last base rate case, the Company adopted a robust and first of its kind COVID-19 Emergency Relief Program ("ERP"). This program provided benefits including billing relief and/or payment relief for customers who needed temporary relief measures during the pendency of the COVID-19 pandemic, as well as for a limited period following the termination of the PUC Emergency Order period, and was available to both qualifying residential and small business customers. The program's benefits for residential customers included: suspension of collection efforts; a onetime credit (up to $400) in an amount equal to 25% of the customer's applicable balance as of the ERP Enrollment Termination Date; automatic CAP screening at the end of the program; and a deferred payment arrangement that is as long or longer than the term provided in the Commission's regulations if an arrearage exists at the end of the program and the customer is not CAP-eligible. In addition, the Company provided an additional $2.0 million in funding for the Operation Share program, including $1.0 million of non-rate recoverable funding. This increased the available funds for Operation Share by approximately 300%.

It is critical to note that in developing these programs, the Company worked collaboratively with the same parties and witnesses participating in this proceeding in order to quickly provide more support to the Company's customers and to adopt some of the first robust utility COVID-19 relief programs.

Q. Has the Company undertaken any further efforts since its last rate case?

A. Yes. Since the conclusion of the last rate case, the Company also filed its "Petition of UGI Utilities, Inc. – Gas Division For Expedited Approvals: (1) To Implement Phase II Of Its COVID-19 ERP; (2) To Implement Further Voluntary, Temporary Modifications To Its Universal Service And Energy Conservation Plan; And (3) For Accounting And Regulatory Approvals Associated With The Costs To Implement Phase II Of The COVID-19 ERP" at Docket No. P-2021-3023839 ("UGI Gas Phase II Petition"). Therein, the Company proposed to implement "Phase II" of the COVID-19 ERP implemented in the 2020 Gas Base Rate Case, and proposed to voluntarily continue the implementation of the temporary modifications to its existing USECP to continue the expanded assistance and protection commitments approved in 2020 Gas Base Rate Case Order. The proposed benefits to residential customers of the “Phase II” ERP included, suspension of collection efforts through April 30, 2021, the availability of $1 million in one-time bill credits to be used to offset residential arrears, and the automatic screening of all customers enrolled in the ERP for CAP and Operation Share eligibility. However, the Commission did not approve the “Phase II” ERP.

Since the onset of the COVID-19 pandemic, the Company has taken a number of steps (many of which were voluntary) to expand assistance to customers that may have been impacted.

Q. Were customers able to access these relief programs?

A. Yes. Mr. Brown provides metrics related to the additional customers UGI Gas was able to assist through its relief programs in pages 13 through 15 of his testimony.

Q. Do you have any ability to quantify how many customers experiencing a temporary financial crisis due to COVID-19 were able to take advantage of the Company’s assistance programs?

A. Yes, to some extent we can identify trends showing that the Company’s programs provided benefits to many customers that had previously not been using low-income assistance programs. For instance, in the early part of the pandemic, many customers suddenly found themselves with no or a significantly reduced income and therefore could qualify for CAP. As a result, CAP enrollment increased by 16% from FY 2019 to FY 2021. The Company recently began its efforts to recertify CAP customers. Of the first 4,049 customers the Company attempted to recertify in October 2021, only 16% of the customers recertified.

In January 2022, the Company began the recertification process for another group of 3,939 customers, and only 17% of those customers recertified. This is exactly what should be expected based on the circumstances surrounding the COVID-19 impact where customers temporarily needed assistance to successfully manage a financial crisis.

It is worth noting here, however, that when comparing the pre-COVID data to the most recent data, the Company's CAP current enrollment (May 2022) continues to exceed pre-COVID levels (September 2019) and is expected to grow as we approach the 2022-2023 winter heating season. This shows that the Company has continued to expand the number of customers it can assist.

Q. Do you have any concluding thoughts on the impacts of COVID-19 on the Company's customer assistance programs?

A. Yes, I do. Many of the recommendations made by the other parties' witnesses in this proceeding either ask the Commission to compel UGI Gas to repeat the voluntary actions it took in response to the unanticipated and unprecedented impacts of COVID-19 on Pennsylvania, even when doing so could have negative tax consequences, as I will describe in Section II.E of my rebuttal testimony. The Commission should recognize in considering these issues that the voluntary actions taken by the Company in response to COVID-19 need not be continued in light of the transition back to pre-COVID-19 employment rates and the increase in other state and federal programs, as I will describe later in this testimony.

Q. Do you agree with Mr. Colton statement that the Company's " customer satisfaction does not support an upward adjustment in the return on equity" (OCA St. No. 4, p. 49)?

A: No, I do not. Mr. Colton selects a few of the many metrics presented by the PUC Customer Service Performance Report 2020. The metrics identified have a very narrow band of separation between utilities survey results. He also does not provide a comprehensive review of all metrics at which the Company does excel or is in the higher percentage. For example, as shown in table below, customers are very satisfied with the Company's automated phone system, which has shown steady improvement over the three years. Further, the "Satisfaction with Ease of Reaching the Company" shows minimal difference in bands of results among the NGDC peers in 2020 (92%-93%).

Table 1A
NGDC Survey Results 2018-2020

Company	Satisfaction with Ease of Reaching the Company*			Satisfaction with Using NGDC's Automated Phone System*		
	2018	2019	2020	2018	2019	2020
Columbia	90%	92%	93%	87%	81%	86%
Peoples	89%	90%	92%	84%	87%	85%
Peoples-Equitable	88%	89%	N/A	84%	82%	N/A
NFG	93%	92%	93%	N/A	N/A	N/A
PGW	88%	89%	92%	85%	82%	90%
UGI-Gas	89%	91%	92%	82%	86%	88%
UGI Penn Natural	88%	89%	**	82%	82%	**
Average	**89%**	**90%**	**92%**	**84%**	**83%**	**87%**

*Percent of consumers who answered either "very satisfied" or "somewhat satisfied" when asked how satisfied they were with this aspect of their recent contact with the NGDC.

Other metrics that show strong performance are "Call Center Representative's Courtesy" and "Call Center Representative's Knowledge." Again, while there are minor variations in the percentages among the NGDCs, the Company's performance remains at a very high level.

Table 4
Consumer Ratings of NGDC Representatives 2018-2020

Company	Call Center Representative's Courtesy*			Call Center Representative's Knowledge*		
	2018	2019	2020	2018	2019	2020
Columbia	96%	97%	97%	94%	97%	95%
Peoples	96%	96%	97%	94%	96%	94%
Peoples-Equitable	97%	94%	N/A	95%	94%	N/A
NFG	96%	96%	97%	95%	93%	96%
PGW	93%	94%	96%	92%	93%	94%
UGI-Gas	95%	94%	97%	93%	92%	95%
UGI Penn Natural	94%	95%	**	92%	94%	**
Average	**95%**	**95%**	**97%**	**94%**	**94%**	**95%**

*Percent of consumers who described the company representative as either "very courteous" or "somewhat courteous" and "very knowledgeable" or "somewhat knowledgeable" when asked about their perception of these aspects of the call center representative.

Lastly, I would like to note that the Company's performance regarding customer satisfaction is very high as based on the Company's performance in JD Power East Large Residential Gas Utility. UGI Gas maintained the second highest score from 2015 through 2021, with the Company being number one in 2014. The Company was among 35 utility companies nationwide recognized as "Easiest to do Business With" in the 2021 and 2022 Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Residential study by Escalent, a leading human behavior and analytics firm.

III. UNIVERSAL SERVICE PROGRAMS

Q. Do you have any overall observations about the other parties' direct testimony and proposals concerning the Company's Universal Service Programs?

A. Yes. Under the expedited schedule of a base rate proceeding, there simply is not enough time to fully investigate and evaluate parties' proposals related to the Company's Universal Service Programs, let alone drastic and unprecedented ones, like Mr. Colton's proposed "outcome objectives," which have not been imposed on any other natural gas distribution company ("NGDC") in Pennsylvania. Without any advance notice of his concerns and recommendations, there is simply inadequate time during a base rate case to properly develop all of the issues raised by Mr. Colton and then come to a rational conclusion on the merits other than to conclude they require more study and should only be applied, if ever, after the parties have had adequate time to debate them. As such, the proper time to propose changes to a utility's USECP is within the context of the utility's USECP proceeding, not a base rate case. In fact, the Commission has recognized that "all aspects" of Universal Service Programs should be addressed in utilities' individual USECP proceedings, as opposed to base rate cases.[1] Accordingly, for this reason alone, the Commission should reject the substantial changes to the Company's Universal Service Programs proposed by the other parties in this base rate proceeding. The Company would add that to the extent Universal Service Program proposals could have wider applicability to other public utilities as well, the proper forum should be a Commission-directed rulemaking.

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[1] *Pa. PUC v. PPL Elec. Utils. Corp.*, Docket Nos. R-2012-2290597, *et al.*, p. 51 (Order entered Dec. 28, 2012).

A. CUSTOMER ASSISTANCE PROGRAM ("CAP")

Q. Does CAUSE-PA witness Geller recommend any changes to the Company's CAP?

A. Yes. He recommends that UGI Gas take other steps to improve its CAP participation rate, which are: (1) simplifying enrollment in CAP for non-CAP Low-Income Heating Energy Assistance Program ("LIHEAP") recipients; (2) referring all customers that call seeking a payment arrangement to apply for CAP and other Universal Service Programs and actively assisting with enrollment; and (3) conducting outreach to all customers who have been removed from CAP for failure to recertify income since the expiration of the Commission's Emergency COVID-19 Order. (CAUSE-PA St. No. 1, pp. 22-26.)

Q. Do you agree with Mr. Geller's recommendations?

A. No. As I discuss in more detail below, the Company already works on each of the issues raised by Mr. Geller as part of its focus to maintain or increase CAP enrollments. Specifically, as to simplifying enrollment in CAP for non-CAP LIHEAP recipients, when a non-CAP customer calls the Customer Contact Center and has received LIHEAP, a Customer Care Representative ("CCR") is directed to inquire if the customer would like to enroll in CAP. Upon affirmative customer response, the CCR has the ability to directly collect verbal income information from the customer and then enroll the customer into CAP based on the self-reported income and occupancy details at the time of the call. This simplified enrollment approach is available and in use today by the Company. As to Mr. Geller's next point that the Company should refer all customers that call seeking a payment arrangement to apply for CAP and other Universal Service Programs, and actively assist with enrollment, the Company's processes address that today. As an example, for material provided to assist a CCR in CAP enrollment, the CCR utilizes the job aid shown below:

Assistance Programs at a Glance

CAP (Customer Assistance Program)

What is it?	"CAP is a low-income program that would change the amount you pay per month to the lowest amount possible. It would be based off either your household income or the monthly average, whichever is the lowest. And as you pay your CAP amount each month, UGI will place a credit towards your true balance to help pay it off."
Eligibility	• Income level 1 (below 150% of Federal Poverty Level) • Residential premise • Gas and/or Electric (can be one or both)
Accounts Not Eligible	• Has an alternate supplier • Landlord/tenant account (L/T) • Meter is foreign load (FORL)
Ways to Enroll	• Rep can send application through COS • If rcvd LIHEAP grant within the last 12months, Credit representative can enroll over the phone ○ If reports zero income or has high usage, will need to complete paper application

Here specifically, the CCR is able to directly send a CAP application to the customer through the Company's Customer Outreach System ("COS"). Lastly, Mr. Geller requests that the Company pursue conducting outreach to all customers who have been removed from CAP for failure to recertify income since the expiration of the Commission's Emergency COVID-19 Order. As described in Section II.B below, the Company has been performing active outreach to these customers since the Emergency COVID-19 Order was lifted by the Commission.

Q. Does Mr. Geller acknowledge these CAP enrollment simplifications and recertification outreach efforts in his testimony?

A. No. He does not.

Q. Did OCA witness Mr. Colton make any observations regarding the Company's CAP?

A. Yes. According to Mr. Colton, UGI Gas has enrolled only a fraction of its Confirmed Low Income ("CLI") customers in CAP. (OCA St. No. 4, p. 7.)

Q. Do you believe Mr. Colton's analysis has provided a complete picture of CLI customers' enrollment in CAP?

A. No. Despite the Company's solicitation efforts, not all eligible customers enroll in CAP. There are various reasons why potentially eligible customers do not complete CAP applications, even considering the simplified enrollment process described above. Among these reasons, some customers do not meet the CAP guidelines outlined in the Company's USECP (e.g., theft of service, utility service in landlord's name, etc.) or fail to verify income eligibility for CAP.

B. OCA'S PROPOSED UNIVERSAL SERVICE PERFORMANCE OBJECTIVES

Q. Mr. Colton recommends that the Commission establish three "measurable outcome objectives that UGI Gas should seek to accomplish with respect to CAP." (OCA St. No. 4, pp. 5, 25-26, 32.) What are those three outcome objectives?

A. As summarized on pages 5 and 25 of Mr. Colton's direct testimony, the three outcome objectives are the following:

1. UGI Gas should achieve a confirmed low-income identification rate, as a percentage of estimated low-income customers, no less than the confirmed low-income identification rate of Pennsylvania natural gas utilities as a whole (excluding UGI Gas);

2. UGI Gas should achieve a CAP participation rate, as a percentage of confirmed low-income customers, no less than the CAP participation rate of Pennsylvania natural gas utilities as a whole (excluding UGI Gas); and

3. UGI Gas should achieve a CAP default rate as a percentage of participants in the lowest poverty level range that is no more than the CAP default rate in that poverty level range for Pennsylvania natural gas utilities as a whole.

Mr. Colton also recommends that the Commission determine that it will use these outcome objectives to review the adequacy of UGI Gas's performance in future base rate cases and that the Commission not tie any penalties or rewards to UGI Gas's performance relative to the outcome objectives in this case. (OCA St. No. 4, pp. 5, 26, 32.) However, Mr. Colton reserved his right to propose penalties related to these outcome performance objectives. He states: "While I would reserve the right to propose a system of penalties (for poor performance as measured by a continuing failure to meet the stated performance objectives) or rewards (for superior performance as measured by exceeding the performance objectives) in a future rate case…" OCA St. No. 4 at 26.

Q. What initial concerns do you have with Mr. Colton's proposals?

A. First, Mr. Colton is effectively attempting to promulgate and impose upon UGI Gas new regulatory standards related to the Company's CAP outside of a Commission-initiated rulemaking. No statutes, regulations, policy statements, or Commission orders require or support the three outcome objectives that Mr. Colton is attempting to impose upon UGI Gas in this case. And, if adopted, as part of this proceeding, these outcome objectives would only apply to UGI Gas. If that happens, UGI Gas would be subject to regulatory standards different than those applied to every other NGDC in Pennsylvania. However, all NGDCs in Pennsylvania should be evaluated under the same regulatory standards. Therefore, Mr. Colton's proposal should be raised, if at all, within the context of a statewide rulemaking proceeding which would permit participation from all stakeholders.

Second, the "rewards" and "penalties" referenced by Mr. Colton appear to be related to the Company's allowed return on equity ("ROE"), given that on page 32 of his testimony he recommends the Company's proposed ROE be evaluated in this case based on his outcome objectives. Mr. Colton fails to recognize that he cannot, either in this proceeding or the future, "propose a system of penalties . . . or rewards" based on the three outcome objectives. Such a system would constitute performance-based rates, a form of alternative ratemaking that the Commission can only approve upon "<u>an application by a utility in a base rate proceeding</u>." 66 Pa. C.S. § 1330(b)(1) (emphasis added). Therefore, only UGI Gas could propose performance-based rates in a future base rate case; such alternative ratemaking mechanisms cannot be forced onto the Company by the OCA. Thus, the Commission should reject any suggestion by Mr. Colton that his proposed outcome objectives can and should form the basis of performance-based rates in the future.

Q. What additional concerns do you have with Mr. Colton's proposed performance objectives?

A. As to the overall desired results of increasing confirmed low-income identification rates, increasing CAP participation rates, and lowering CAP default rates, the Company's programs and procedures already target these low-income objectives today. Also, the Company tracks relevant data on its CAP performance and reports such data in its annual

Universal Service Reports. However, the Commission has not developed Universal Service regulations, performance standards, or metrics that NGDCs must meet as compared to other NGDCs. Therefore, it is unreasonable for OCA to be permitted to do so in this proceeding.

As to the specifics of Mr. Colton's recommendations, they do not recognize that: (1) CAP data for other NGDCs differs from the Company's, given their distinctive customer populations, demographics, and service territories and, therefore, should not be used to develop performance standards; (2) his proposed objectives and the anticipated results are largely out of the Company's control, such as an applicant undertaking necessary steps to follow through and actually sign up for CAP or a customer completing the recertification process to stay enrolled in the CAP program; and (3) additional actions which may influence customer behavior requires the deployment of additional and targeted resources, and Mr. Colton has not outlined any specific measures, anticipated budget amounts which may be spent, or the appropriate cost recovery thereof. Although Mr. Colton wants to dismiss the efforts made by the Company to identify confirmed low-income customers, enroll confirmed low-income customers in CAP, and reduce the CAP default rate, those efforts are real and substantial and should factor into any recommendations made with respect to CAP.

Furthermore, in focusing only on his preferred outcomes, Mr. Colton fails to offer any solutions to achieve those outcomes or any substantive analysis supporting that those outcomes are achievable in the Company's service territory. The Company believes Mr. Colton could be more constructive to identify actions which have proven effective in achieving his preferred results. For example, if Mr. Colton is aware of a particularly successful approach which is being utilized by other NGDCs to identify CLI customers, or to have CLI customers enroll in CAP or to reduce CAP defaults, the Company would welcome discussions which detail how these approaches may or may not transfer well to the UGI Gas service territory and its CAP.

Indeed, among other Company initiatives, UGI Gas has provided Universal Service Program information, including CAP benefits, to customers on a regular basis over the last several years as outlined in UGI Gas Exhibit DVA-2R (UGI Gas's response to OCA-II-46 and Attachment OCA-II-46-d). In addition to bi-annual direct, targeted campaigns to customers who may qualify for Universal Service Programs, the Company has program information on its website, in its "on hold" messaging, in customer newsletters, and in handouts provided by Community Based Organizations ("CBOs").

Also, the Company's CCRs offer information about Universal Service Programs to customers during billing calls. As noted above, if a customer has received LIHEAP but is not enrolled in CAP, the CCR is able to directly enroll the customer in CAP (with the customer's approval) without the customer needing to provide income data to a CBO. In other situations, customers only need to take action to provide household income and occupant details and proof to the CBO for CAP enrollment. Furthermore, in each targeted CAP solicitation, the Company provides clear communication of the CBO name and address, as well as information the customer needs to provide for enrollment. The Company has even provided pre-populated CAP applications to customers.

Q. What is the basis of Mr. Colton's Objective 1 regarding CLI Customer Identification Rate?

A. According to Mr. Colton, the Company should be confirming the income status of more Estimated Low Income ("ELI") customers to increase the number of CLI customers. As support for his claim, Mr. Colton compared UGI Gas to other Pennsylvania NGDCs in Table 5 of his direct testimony. (*Id.* at 26.) Mr. Colton pulled this data from the Commission's 2020 Report on Universal Service Programs & Collection's Performance ("2020 Report"). He divided the number of CLI customers by the number of ELI customers. He calculated a percentage for how many ELI customers have been identified as being CLI by NGDC.

Q. Do you believe that this analysis properly demonstrates the Company's success in confirming the income status of its ELI customers?

A. No. First, it needs to be recognized that the number of ELI customers in the Company's service territory is based upon census data analyzed by Penn State University, which is then provided to the Commission. As such, the census data provided to the Company does not provide any level of information at a customer-specific level; it is only a total for the estimated population. In order to identify an ELI customer within the Company's service territory and move that customer to a CLI category, the Company needs to have engagement – either with the customer directly or through a state agency – which obtains income information from the customer and assesses low-income status. While a master detailed list of all customers and incomes within the UGI Gas service territory would be useful in assigning CLI status to customer accounts, the privacy and protection of customers' personal information is an overriding concern. Thus, how well the Company, or any other utility, assigns CLI status to customer accounts depends on its success in gathering this information directly from customers. Mr. Colton's analysis does not go far enough to paint a true picture. Upon review of multiple years of data between 2018 and 2020 – and not just one year as Mr. Colton has done – the following analysis, shown in Tables 1-3, demonstrates that the Company has made considerable improvement in its efforts to identify CLI customers as compared to its total ELI customer base.

Table 1

	2018 CLI Customers	2019 CLI Customers	2020 CLI Customer
Columbia	67,590	67,582	68,078
NFG	30,661	32,282	35,241
PECO Gas	25,704	24,977	26,216
Peoples	104,976	109,303	108,540
PGW	149,217	147,014	133,785
UGI	56,760	64,042	77,553

Table 1 contains the number of CLI customers between 2018 and 2020 as appearing in the Commission's 2020 Report.

Table 2

	2018 ELI Customers	2019 ELI Customers	2020 ELI Customers
Columbia	99,925	97,268	96,648
NFG	59,009	60,947	59,860
PECO Gas	74,121	74,914	80,638
Peoples	131,652	143,228	152,309
PGW	206,533	197,855	195,215
UGI	138,102	132,611	151,918

Table 2 contains that number of ELI customers during the same period as appearing in the 2020 Report.

Table 3

	2018 Percent CLI of Total ELI	2019 Percent CLI of Total ELI	2020 Percent of CLI of Total ELI	Improvement over 3 years
Columbia	67.64%	69.48%	70.44%	4%
NFG	51.96%	52.97%	58.87%	13%
PECO Gas	34.68%	33.34%	32.51%	-6%
Peoples	79.74%	76.31%	71.26%	-11%
PGW	72.25%	74.30%	68.53%	-5%
UGI	41.10%	48.29%	51.05%	24%

Table 3 divides Table 1 data by Table 2 data in order to calculate how many customers the Company has identified as CLI as a percentage of the total ELI population. In reviewing this comparison, UGI Gas has increased its percentage of CLI customers relative to the overall ELI population in the Company's service territory by 24 percent from 2018 to 2020, which is a significant improvement. In fact, the Company's performance over this timeframe exceeds any other NGDC in this area. Moreover, when viewing for data through January 2022 against the base of 2021 ELI population (as 2022 data is not yet available), the 24 percent noted above has been increased to 29 percent, further demonstrating the Company's strong performance. As such, Mr. Colton's desired Objective 1 is not the "snapshot" standard that should be used by the Commission to evaluate performance, because a broader review is needed. When that broader view is undertaken, the Company's efforts have been producing substantial results.

Q. What is the basis for Mr. Colton proposing his Objective 2 regarding CAP Participation Rate?

A. According to Mr. Colton, UGI Gas should be increasing CAP participation rates among CLI customers to a level more comparable to the average of its natural gas utility peers in Pennsylvania. (OCA St. No. 4, pp. 26-32.)

Q. Do you agree that Mr. Colton's analysis is an accurate representation of the Company's performance in this area?

A. No. Here again, Mr. Colton's "snapshot" approach does not paint a full picture. Chart 1, which is set forth later in my rebuttal testimony, shows the Company's progress and success in increasing CAP participation levels for the period December 2018 through March 2022. As can be seen from this data, the Company has materially improved CAP participation rates from just four years ago. Thus, Mr. Colton's proposed Objective 2 is not the correct standard by which the Company's performance should be measured.

Q. What is the purpose of Mr. Colton proposing his Objective 3 regarding CAP Default Rate?

A. According to Mr. Colton, between 2018 and 2019, UGI Gas's CAP Default Rate (for customers below 50% of the FPL) was one of the highest in Pennsylvania. It is important to note the overall trends, as shown in response to OCA-II-16 as provided in UGI Gas Exhibit DVA-6R, which demonstrate four key reasons for CAP exits. Customers are moving to a new residence, failing to recertify, choosing a payment arrangement, and/or failing to pay. From October 2017 through March 2020, the average monthly CAP exits as a percent of total CAP exits for the following categories were: (1) moving - 72% of total exits or 280 CAP Customers; (2) failure to recertify - 5% or 23 CAP Customers; (3) non-payment - 9% or 46 customers; and (4) opted for payment arrangement – 2% or 10 customers. There were then no CAP exits for the COVID pandemic period of April 2020 through April 2021 for categories (2) and (3). Subsequently, the same statistics for the time period of May 2021 to December 2021 were: (1) moving - 42% of total exits or 317 CAP Customers; (2) failure to recertify - 28% or 373 CAP Customers; (3) non-payment - 3% or 23 customers; and (4) opted for payment arrangement – 15% or 115 customers.

Notable trends included the increase in CAP failure to recertify post COVID-19 even with significant outreach efforts. Another notable change in trends was the increasing amount of CAP customers opting for COVID-19 payment arrangements versus historical. Mr. Colton's comment that these numbers are unacceptable does not account for the true reason behind the change nor does it factor in the historical trends, which showed the rates of customers' failure to recertify and failure to pay were low. Historically, the most common reason for CAP exits was customers moving. From October 2017 through March 2020, 23 customers per month, on average, exited the CAP program due to failure to recertify. This is approximately 0.098% of the total CAP population in 2019. For the same period, CAP exits due to non-payment was on average 46 customers per month or 0.2% of the total CAP population in 2019.

Moreover, Mr. Colton does not recognize that the apparent decrease in CAP enrollments in 2022 is misleading. Due to COVID-19 restrictions, CAP enrollments were elevated in 2020 and much of 2021. And, because the CAP recertification process was on hold, the annual attrition and renewal process typically experienced was not reflected in the 2020 and 2021 CAP enrollment data. In fact, much of the decrease in CAP enrollments from 2021 to 2022 was the result of the CAP recertification process, specifically the Commission's mandate in July 2021 that utilities begin recertification efforts that had been on hold due to COVID-19.

As part of the recertification process, UGI Gas sent an initial Recertification Reminder Letter, a second Recertification Anniversary Letter, and a Final Letter. Further, each CBO was tasked with reminding customers that recertification was required.

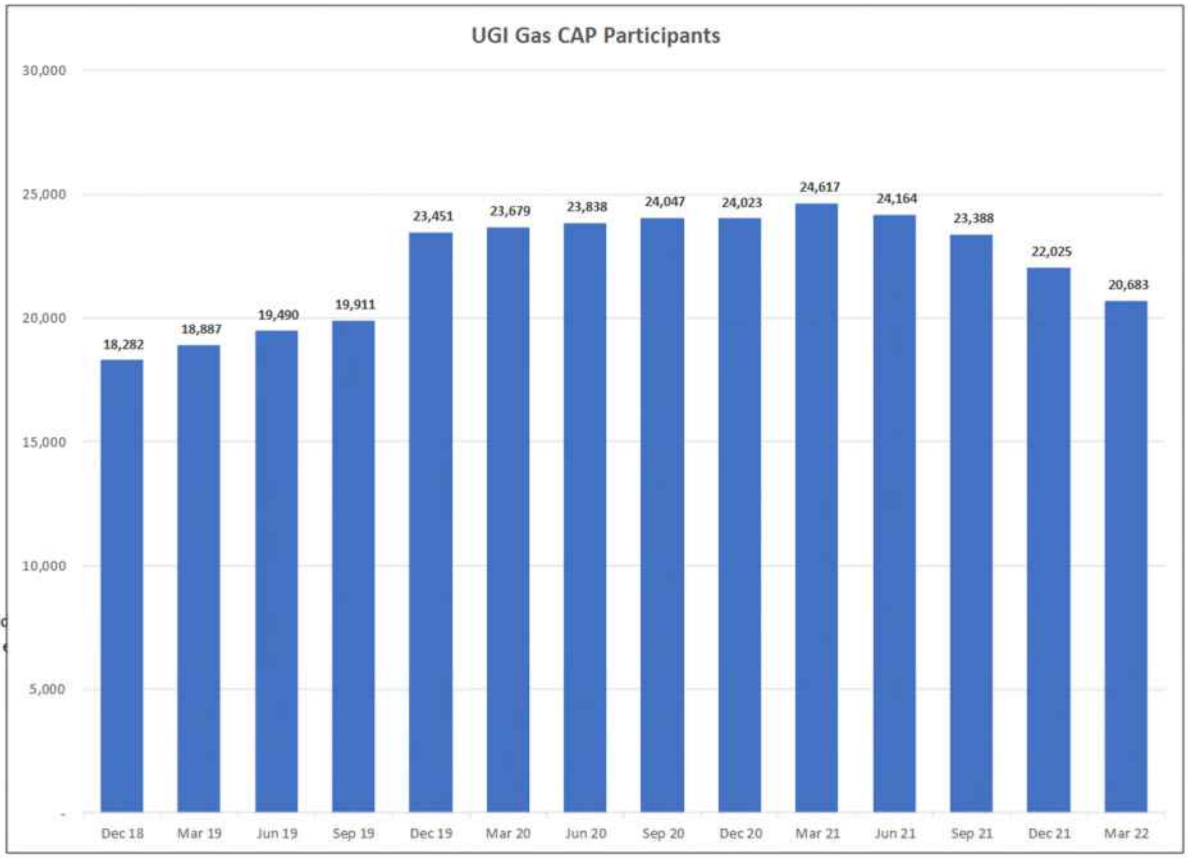
In October 2021, the Company sent the recertification communications to approximately 4,049 customers that needed to recertify. Notably, the Final Letter's envelope stated that the CAP program benefits would be lost if no action was taken. For customers with an email on file, the Company also sent them an email stating that recertification steps needed to be taken and asking them to watch their mail for information about how to recertify. To make the recertification process easier for the customer, this email included CBO-specific information as well as the customer's account number.

Of those 4,049 customers, only 16% of the customers recertified. The other 84% of the 4,049 customers failed to recertify and were removed from CAP. In January 2022, the Company began the recertification process for another group of 3,939 customers. The process was the same as outlined previously for the October 2021 recertification communications. Of those 3,939 customers, only 17% recertified. The other 83% of the 3,939 customers did not recertify and were removed from CAP.

For these reasons, the decrease in CAP enrollment in 2022 appears elevated when comparing 2019, 2020, and 2021 data. However, when comparing the pre-COVID data to the most recent data, the Company's CAP current enrollment (May 2022) continues to exceed pre-COVID levels (September 2019) and is likely to grow as we approach the 2022-2023 winter heating season. Chart 1 shows the steady growth in CAP participation through the Company's efforts, but also highlights the impact of the Commission's Emergency

COVID-19 Order, which negated the normal attrition experienced during non-COVID-19 periods and resumption of the required recertifications.

<u>Chart 1</u>



UGI began conducting WARM events and semi-annual CAP enrollment campaigns in Fall of 2019. The Emergency Order was in effect from March 2020 through June 2021, which halted customers having to recertify to remain in CAP. Recertification began in July of 2021, which caused the decrease in CAP participants and offsets CAP enrollment additions occuring July 2021 through present.

Q. Mr. Colton also claims that these outcome objectives are "appropriate" to address in this base rate case instead of the Commission's review of the Company's USECP. (OCA St. No. 4, pp. 32-33.) Do you agree?

A. No. The Company's USECP is a Commission-approved plan where issues relating to the Universal Service Programs' design, budgets, and marketing are addressed. As explained previously, it is inappropriate to alter the USECP's objectives in this proceeding.

Moreover, such changes necessarily affect the approved program design, budgets, and marketing in the Company's current USECP. Additionally, the Commission already has reporting regulations in place to evaluate NGDCs' performance across multiple uniform reporting measures, which include Universal Service Programs & Collections Performance, Customer Service Performance Reports, and Rate Comparison reports to name a few.

Moreover, the Company should not be evaluated based on metrics that did not exist prior to this base rate case. Mr. Colton claims on page 32 of his direct testimony that the Company's failure to achieve these objectives demonstrates, at the very least, that the Company's proposed return on equity should not be approved. It is short sighted for Mr. Colton to evaluate the Company's performance based on non-existing criteria and to disregard other performance measures as well as COVID-19's impact on the recertification of CAP customers after the Commission's emergency moratorium. The Company has taken a number of steps pre- and post-COVID to support low-income customers. For example, UGI Gas Exhibit DVA-2R shows a significant number of communications that were partnered up with the Company's WARM initiative.

The WARM initiative[2] kicked off in October 2019, in recognition of growing arrears within the low-income sector. One of the most significant benefits shown was a great ability for the Company's WARM team to assist customers with completing the required documents for various Universal Service Programs. In December 2019, the

[2] The WARM initiative consists of Company employees from multiple discipline departments, with the focus of hosting events at UGI offices and partnering with CBOs to provide in-person support to help answer customer questions and offer guidance on enrollment in multiple low-income programs. UGI Gas programs and resources include funds available through LIHEAP, CAP, Operation Share, the Customer Assistance and Referral Evaluation Services ("CARES") program, and LIURP.

WARM team implemented the first round of WARM activities to increase CAP enrollments based on prospective CAP customers identified in the Company's Customer Information System. Although COVID-19 has impacted in-person events, the Company continues to inform low-income customers through multiple multi-media avenues which include the semi-annual CAP enrollments. Additionally, the Company voluntarily implemented a phase 1 of its ERP that allowed customers who received federal COVID-19 stimulus grants or impacted by COVID-19 to receive a one-time grant and extended payment arrangement. The Company proposed an ERP phase 2 of this program but did not receive a majority ruling from the Commission to implement a program extension. These efforts show the Company's focus and effort to maximize enrollments in current customer programs and creative new programs to help those in need.

C. LOW-INCOME SCREENING FOR NATURAL GAS CONVERSIONS

Q. OCA witness Colton recommends that the Company be required to screen customers whom it assists with conversions to natural gas, to see if they are confirmed low-income customers and to enroll them in CAP where appropriate. (OCA St. No. 4, pp. 4, 15-20.) Do you agree with this recommendation?

A. No. First and foremost, Mr. Colton makes this recommendation in reliance on the data that the Company provided in the response and Attachment to OCA-V-9. As stated in the Company's response to OCA-V-9: "The Company does not track household mobility. Therefore, the Company is only able to query the original customers who are active in the Customer Information System ("CIS") and remain at the converted premise. The detailed data is not available prior to 2004."

The data provided in Attachment OCA-V-9 shows that on average over the 18-year period contained therein (2004-2021) approximately 49 customers, which currently reside at the conversion addresses presented, are currently confirmed low income. Additionally, on average during that period, approximately 24 customers, who live at the addresses that were converted to natural gas over that 18-year period, are currently on CAP. Based on (1) these figures, (2) these customers converting to natural gas at some point over the past 18 years, and (3) a small amount of the customers at these conversion sites being low income, Mr. Colton recommends that when new customers seek to convert to natural gas, UGI Gas screen them to determine income status. (*Id.* at 20.)

Based on the foregoing, I do not believe Mr. Colton's recommendation is necessary. Currently, when processing a natural gas conversion, the Company performs a credit check to verify the customer's identity; the Company does not collect income and household occupant information during that process. Nor is the Company required to do so by regulation. Were the Company to undertake this new obligation, as proposed by Mr. Colton, UGI Gas's CIS would require significant programming to track and store income and occupant information for prospective customers. The Company has determined that only approximately 1.6% of the 2021 natural gas conversions (i.e., the 85 customers reported on Attachment OCA-V-9) were confirmed low-income customers as of March 2022.

In addition to this very small number of potential low-income converting customers, the Company on average receives approximately 9,000 natural gas conversion leads annually, all of which would need to be screened under Mr. Colton's recommendation. In addition to the cost to enhance the CIS so that it can track and store this data for prospective customers, the Company believes Mr. Colton's recommendation would be ineffective when compared to the efforts described above to solicit new CAP participants post-conversion. Additionally, Mr. Colton fails to present any substantive evidence that justifies residential customers bearing the costs of these proposed changes, which would, at most, benefit a very small number of potential low-income converting customers.

D. LOW-INCOME USAGE REDUCTION PROGRAM ("LIURP")

Q. OCA witness Colton recommends that the Company add a new incremental component to its LIURP through which the Company will provide LIURP energy conservation measures to confirmed low-income customers as part of the process of converting those customers to natural gas. (OCA St. No. 4, pp. 4-5.) Do you agree with this recommendation?

A. No. As I explained previously, Mr. Colton's proposed screening process is unjustified and unnecessary. The Company has determined that approximately 1.6% of the 2021 natural gas conversions were confirmed low-income customers as of March 2022. Furthermore, if Mr. Colton's recommendation is adopted, the "incremental component" of the LIURP would circumvent one of the key criteria for enrollment in LIURP, which is 12 months of usage that meets program thresholds. Since conversion customers are converting from an alternate fuel source, the Company would not have pre-weatherization usage data available, which prevents consistent and accurate reporting of LIURP results when filing regulatory reports and complying with USECP requirements. Thus, this recommendation should be denied because the measures needing to be evaluated will be lacking critical data to prove program effectiveness.

Q. Mr. Colton also suggests that UGI Gas expand its LIURP spending by $1.425 million per year, so that the Company can serve 231 additional confirmed low-income customers per year. (OCA St. No. 4, pp. 6, 41-43.) Mr. Colton further claims that his LIURP funding proposal is appropriate to address in this base rate case instead of the Commission's review of the Company's USECP. (OCA St. No. 4, p. 43.) Do you agree with Mr. Colton's recommendations?

A. No. LIURP is an effective program and has been recognized as such by the Commission. However, it is inappropriate to increase the amount of LIURP funding, which was approved by the Commission in UGI Gas's current USECP, in this rate case proceeding. First, I am advised by counsel that the OCA's proposal does not comply with 52 Pa. Code § 58.4(c), which sets forth the factors to be considered when revising a utility's LIURP funding. In fact, none of the parties in this proceeding have testified to any of those factors, which are:

- The number of eligible (high usage) customers that could be provided cost-effective usage reduction services.
- The number of customer dwellings that have already received, or are not otherwise in need of, usage reduction services.
- Expected customer participation rates for eligible customers.
- The total expense of providing usage reduction services, including costs of program measures, conservation education expenses and prorated expenses for program administration.

- A plan for providing program services within a reasonable period of time, with consideration given to the contractor capacity necessary for provision of services and the impact on utility rates.

Critically, Section 58.4(c) of the Commission's regulations does not list rate case impacts or changes to the customer charge as factors for revising LIURP budgets. Therefore, the OCA's proposal should be rejected by the Commission and addressed in the context of the Company's next USECP proceeding, where a needs assessment would be completed to help determine the appropriate budgeting levels for LIURP.

Additionally, Mr. Colton has not demonstrated how OCA's requested percentage increase in LIURP funding ties to the proposed increase in rates for residential customers. Mr. Colton has not supported his fundamental premise that an increase in base rates proportionally increases the need for LIURP. Furthermore, the Company's proposed base rate increase has no impact on the qualifying criteria for participation in the Company's LIURP, such as meeting certain usage thresholds or residing in properties suitable for weatherization.

Furthermore, Mr. Colton is making spending recommendations based on annual LIURP spending of $2.1 million. However, the Company already has an approved USECP with an approximate $3.7 million annual LIURP budget, so his recommendation to increase spending by $1.425 million is already within budgetary guidelines. In addition to the 10 current gas CBO LIURP contractors that UGI Gas utilizes, the Company recently expanded its LIURP contractor network by adding 5 new Building Performance Institute ("BPI") weatherization contractors. This 50% increase over the Company's current LIURP vendor network demonstrates that UGI Gas is making a strong effort to utilize the available LIURP budget. In fact, through the first 3 months of calendar year 2022, LIURP spending has been $995,452, which represents a 170% year over year increase from Q1 2021.

Q. Does CAUSE-PA witness Geller make any recommendations concerning the Company's LIURP?

A. Yes. Mr. Geller recommends that UGI Gas: (1) reduce its LIURP minimum usage threshold for households at or below 150% of the FPL; and (2) at a minimum, increase its annual LIURP budget by a percentage at least equal to the average residential bill impact of any approved residential rate increase. (CAUSE-PA St. No. 1, pp. 27-29.) As alleged support for his recommendations, Mr. Geller states that "[d]espite the value of UGI's LIURP and its impressive results, UGI's LIURP is not operating at a rate sufficient to fulfill the estimated need for comprehensive usage reduction services within a reasonable amount of time." (CAUSE-PA St. No. 1, p. 26.)

Q. Do you agree with Mr. Geller's recommendations for the Company's LIURP?

A. No. As stated above in response to Mr. Colton, it is not appropriate to increase LIURP funding through this proceeding. The Company is already adhering to the Commission-approved LIURP minimum usage thresholds and annual budgets set forth in the Company's USECP.

Q. Does CEO witness Brady recommend any modifications to the Company's LIURP?

A. Yes. He recommends that the annual LIURP funding be increased by $750,000 effective upon the date new base rates take effect. (CEO St. No. 1, p. 8.) Mr. Brady argues that the

$750,000 funding recommendation was derived based on an additional 100 LIURP jobs per year, which would be a "good target . . . across the Company's territory." (CEO St. No. 1, p. 9.) In discovery, Mr. Brady clarified that he derived his $750,000 figure based on an "approximate job cost" of $7,500 "derived from Appendix A of the Company's 2020-2025 USECP." (*See* UGI Gas Exhibit DVA-3R.) Specifically, he took the total projected budget for the Company's three former divisions and then divided that total projected budget by the total projected participation levels.

Q. Do you agree with Mr. Brady's recommendation?

A. No. As previously stated in my testimony on the LIURP funding in response to both OCA and CAUSE-PA, it is improper to increase LIURP funding through this proceeding. The Company is already adhering to the annual budgets set forth in its Commission-approved USECP.

E. OPERATION SHARE

Q. Does CAUSE-PA witness Geller make any recommendations for the Company's Operation Share?

A. Yes. He recommends that UGI Gas: (1) increase the maximum grant amount for customers at or below 150% FPL; and (2) increase its annual Operation Share contribution by an amount that is at least proportional to its residential rate increase. (CAUSE-PA St. No. 1, pp. 30-32.) As alleged support, Mr. Geller contends that "[d]espite the availability of additional Operation Share funds and the increase in the number of grants award, UGI low income customers still experienced a disproportionate increase in termination rates."

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(CAUSE-PA St. No. 1, p. 30.) Mr. Geller believes his recommendation will help address the increase in low-income termination rates. (CAUSE-PA St. No. 1, p. 30.)

Q. Do you agree with Mr. Geller's recommendation?

A. No. As shown below in Chart 2, the Company started to increase its annual direct funding prior to COVID-19 from what it traditionally made available to support Operation Share in addition to employee and customer contributions that help fund the program. In 2019, the Company increased direct funding for UGI Gas from $104,500 to $584,500 annually or greater than 500%, and UGI Gas continues to contribute at the increased funding level. This also does not account for the one-time incremental $2,000,000 added to the program during 2021/2022, as part of the UGI Gas 2020 Base Rate Case settlement. Increasing the maximum grant amount for customers as proposed by Mr. Geller will reduce the number of customers being able to take advantage of the program's funding due to the proposed higher grant levels. In addition, it is important to note the newly introduced federal programs and increased funding for existing federal programs, such as Emergency Rental Assistance Program ("ERAP") and Pennsylvania Homeowner Assistance Fund ("PAHAF"), and LIHEAP, all of which support low-income customers in addition to the Company's CAP, which are described in more detail further on in my testimony.

Q. Similarly, CEO witness Brady recommends that UGI Gas increase donations to Operation Share by $1 million (CEO St. No. 1, pp. 11-12.) Please respond.

A. Mr. Brady clarified in discovery that his proposal is for UGI Gas to make a one-time increase in donations to Operation Share of $1 million, as opposed to the Company increasing donations to Operation Share by $1 million annually. (*See* UGI Gas Exhibit DVA-4R.) With that clarification and in response to Mr. Geller's request to increase funding to Operation Share, the Company believes that adequate funding is already provided by the Company to Operation Share. The Company also believes that the Commission does not have the authority to mandate funds to a 501(C)(3) tax charitable organization which are not recovered through the ratemaking process. For these reasons, the parties' recommendation for additional funding should be rejected.

Q. Do you have any additional concerns regarding Mr. Geller's and Mr. Brady's Operation Share recommendation?

A. Yes, the Company's donations to Operation Share are made through a charitable organization that allows the payments to receive a tax deduction. These donations are made voluntarily and are not mandated by the Commission. The voluntary nature of these donations allows the Company to retain the tax advantaged nature of the organization. Contributions made as a result of the Commission's acceptance of Mr. Geller and Mr. Brady's recommendations would not be voluntary and may cause the contribution to lose their tax-advantaged status, requiring the Company to pay taxes on the contributions. Therefore, acceptance of their funding recommendation likely would come at an unanticipated cost. Similarly, if the Commission were to mandate the expenditure, the Company would be entitled to recover the Operation Share Donations from its customers, again coming at an additional cost to customers, and potentially come at another added cost because they likely would lose their tax-deductible status because they are no longer voluntary. Today, the Company's donations are voluntary, tax deductible, and not recovered through the ratemaking process.

F. USE OF COMMUNITY-BASED ORGANIZATIONS

Q. CEO witness Brady recommends that UGI Gas be directed to continue using CBOs in the administration and implementation of its Universal Service Programs. (CEO St. No. 1, pp. 10-1.) Please respond.

A. The Company recognizes the benefits of CBOs in increasing cross-Universal Service Program participation and utility referrals. As set forth in the Company's Commission-approved USECP, UGI Gas will continue using CBOs in the administration and implementation of its Universal Service Programs assuming CBOs fulfill contract obligations as agreed to between CBO and Company. Thus, there is no reason for the Commission to issue such a declaration in this base rate proceeding.

IV. IMPACT OF THE COMPANY'S PROPOSALS ON LOW-INCOME CUSTOMERS

A. BASE RATE INCREASE

Q. CAUSE-PA witness Geller contends that UGI Gas's existing Universal Service Programs do not adequately address the affordability gap for economically vulnerable customers and that the rate increase will make it more difficult for low-income customers to maintain safe energy services to their home. (CAUSE-PA St. No. 1, p. 5.) Do you agree?

A. No. I believe that the Company's Universal Service Programs are well-designed and have been successfully assisting low-income customers. Additionally, external programs to support payment troubled customers are also available. These federally funded programs include ERAP, PAHAF, and LIHEAP. Some of these programs, such as ERAP and PAHAF, are newly available and can help support customers, as can increased funding for LIHEAP. The Company actively promotes these external programs to customers in addition to the Universal Service Programs, as shown in UGI Gas Exhibit DVA-2R.

Q. Relatedly, Mr. Geller claims that the proposed rate increase will lead to corresponding increases in payment-related terminations and uncollectible expenses. (CAUSE-PA St. No. 1, pp. 9-13.) Do you agree?

A. No. In addition to the Company's increased funding for low-income customers through Operation Share, there are externally funded programs that have either increased funding to help customers in need (such as LIHEAP) or have been newly made available to customers that qualify through ERAP and PAHAF. For example, Chart 2 shows the increase in Operation Share grants provided to customers over the period of FY2019-FY2022 to date. Additionally, Chart 3 shows the significant funding increases in LIHEAP dollars available to Pennsylvania residents, and Chart 4 shows the impact in increased funding that UGI Gas's customers have benefited from to help with their energy costs.

Chart 2

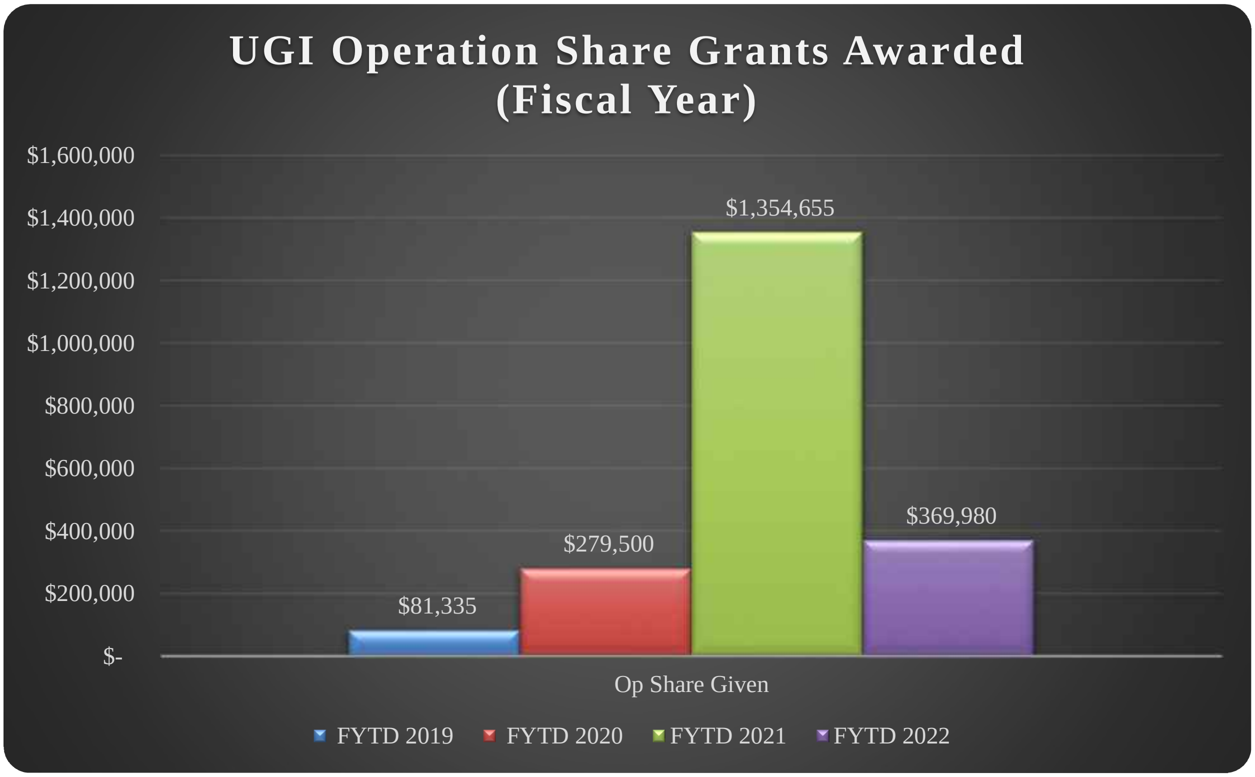
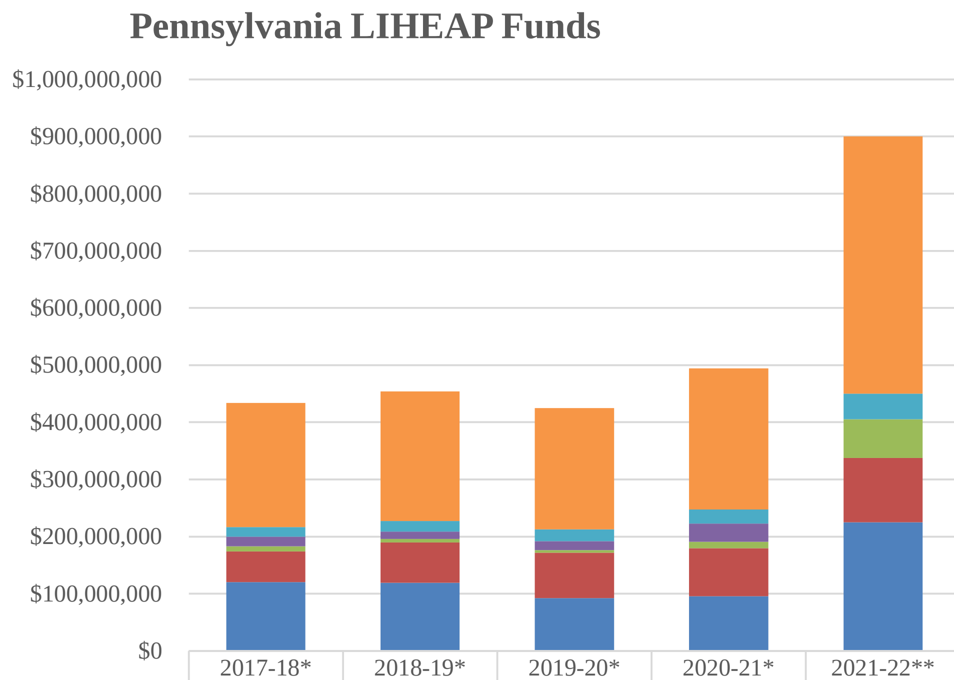

UGI Operation Share Grants Awarded (Fiscal Year)
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
$81,335
$279,500
$1,354,655
$369,980
Op Share Given
FYTD 2019
FYTD 2020
FYTD 2021
FYTD 2022

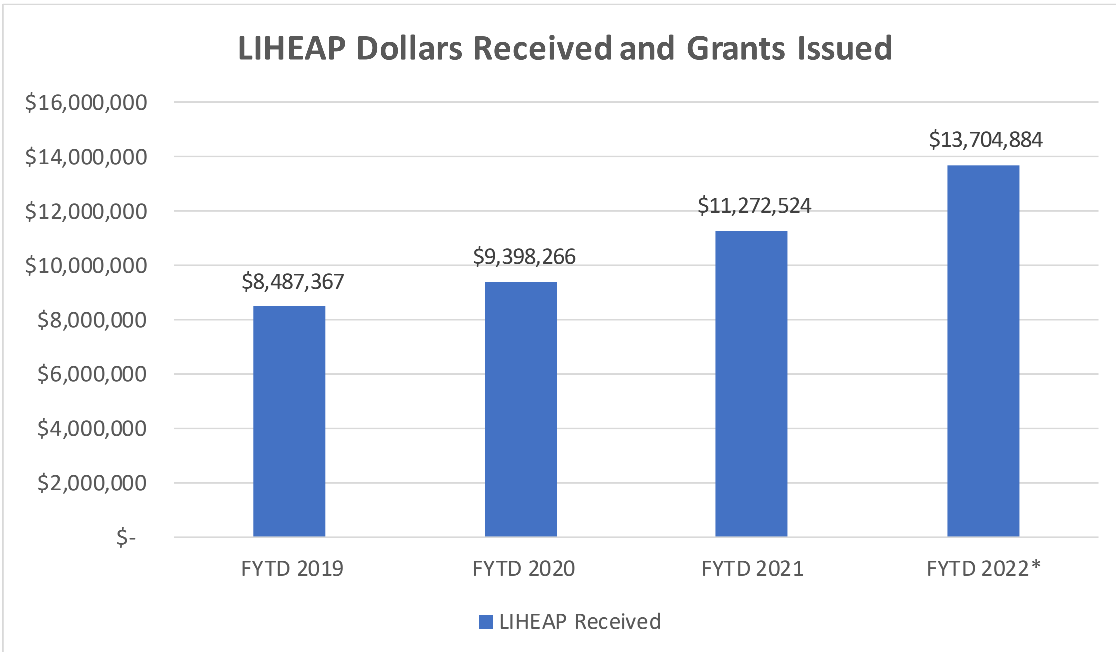
Chart 3



	2017-18*	2018-19*	2019-20*	2020-21*	2021-22**
Total	$216,785,888	$227,104,039	$212,515,010	$247,280,415	$450,000,000
Funds Used for Administration - Total	$16,984,902	$18,611,278	$20,637,486	$24,484,643	$45,000,000
Funds Used for Carryover - Total	$17,077,332	$12,520,379	$15,382,736	$31,965,247	
Total Benefits - Weatherization	$8,582,272	$6,174,472	$4,789,670	$11,035,570	$67,500,000
Total Benefits - All Crisis	$53,604,094	$70,554,928	$79,405,388	$83,907,920	$112,500,000
Total Benefits - Heating	$120,537,288	$119,242,982	$92,299,730	$95,887,035	$225,000,000

Chart 4[3]

UGI Gas LIHEAP Customer Grants Awarded



*FYTD April 30, 2022

Q. Mr. Geller contends that customers enrolled in CAP who pay based on an average bill are not insulated from the financial impact of the proposed base rate increase, but even customers who pay based on percentage of income ("PIP") or minimum bill will produce increased CAP costs due to the proposed base rate increase. (CAUSE-PA St. No. 1, pp. 18-21.) Please respond.

[3] The source of Chart 4 is https://liheappm.acf.hhs.gov – the LIHEAP Performance Management Site for 2017-18, 2018-19, 2019-20, 2020-21. Program year 2021-22 is based on the LIHEAP State report at https://www.dhs.pa.gov/Services/Assistance/Documents/Heating%20Assistance_LIHEAP/2022%20LIHEAP%20State%20Plan_FINAL%20Approved.pdf

A. UGI Gas witnesses Ms. Heppenstall (UGI Gas St. No. 10-R) and Mr. Taylor (UGI Gas St. No. 11-R) explain in detail why the Company's proposed residential monthly customer charge is reasonable. In addition to their testimony, it is important to recognize that, in large part, low-income residential customers are either: (1) shielded from the impact of the increase to the residential monthly customer charge; or (2) not unreasonably burdened by a rate increase that increases a fixed charge versus a volumetric charge. Moreover, depending on their usage, low-income residential customers can benefit from a higher customer charge, as shown in the rebuttal testimony of Mr. Taylor (UGI Gas St. No. 11-R).

In addition, the Company has shown growth in CAP enrollments over the past few years, as shown in Chart 1 above. I would also like to note that although Mr. Geller states that the Company's CAP Participation Rate is below average when compared to other NGDCs, he fails to provide a full frame of reference of the data and external impacts that have caused a slight decrease in UGI Gas's CAP counts. To start, Mr. Geller states that UGI Gas has dropped from a CAP participation rate of 35% in 2020 to 28% in 2021. My Chart 1 above shows that the Company's CAP participation rate is much higher than Mr. Geller claims, in part because it includes CAP participants for the former UGI Central rate district.

Moreover, CAP participation levels dropped in 2021 as a result of the Commission's requirement to restart the CAP recertification process for the first time since the Commission's March 2020 Emergency COVID-19 Order. As I explained previously, the Company undertook significant efforts to contact CAP customers about recertifying. Mr. Geller's data also does not show how other NGDCs performed in 2021 who were also required to recertify their CAP customers. Also, TABLE 3: CAP Participation Rate in Mr. Geller's direct testimony does not show the full subset of data as reported to the Commission in the annual Universal Service Programs & Collection Performance Reports. It is important to note that the Company has increased its CAP participation from December 2018 to through December of 2020 by 31% and with the impacts described from COVID-19, still see an increase in CAP participation from December 2018 through March 2022 by 13%. All other utilities published from December of 2018 through December of 2020 had a loss of CAP customers with the exception of PGW who saw an 8% increase in customer counts. This data shows again that the Company's efforts have increased participation at a greater rate than other NGDCs.

Q. Mr. Geller also recommends that UGI Gas be required to implement the reduced maximum energy burden standards proposed in the Company's petition to modify its USECP as a condition to approval of any rate increase in this proceeding. (CAUSE-PA St. No. 1, p. 22.) Please respond.

A. The Company has formally filed and complied with the Commission's requirement to implement a reduced maximum energy burden standard. This proposal is the subject of another Commission proceeding at Docket No. P-2020-3019196 and was not consolidated with this base rate case proceeding. Therefore, it is imprudent to introduce that separate proposal here or make the base rate increase conditional on that proposal.

Q. CEO witness Brady contends that even though he does not take a position on whether the proposed base rate increase should be granted, he believes that granting the

proposed base rate increase will call into question whether the Company's Universal Service Programs are adequately funded. (CEO St. No. 1, pp. 5-6.) Please respond.

A. Mr. Brady fails to present evidence on what the "adequate" level of funding should be for the Company's Universal Service Programs under the proposed base rate increase. Moreover, as I previously explained, LIURP funding should not be changed through this base rate case, and even if it were, the other parties fail to address the Commission's factors for determining the appropriate levels of USECP funding. Additionally, the Company proactively increased funding in FY2019 for its Operation Share grants by increasing the annual funding by more than two hundred percent (200%). Specifically, the annual funding for Operation Share increased from $104,500 to $584,500. For these reasons, and based on the Commission-approved budgets in the Company's USECP, UGI Gas's Universal Service Programs are adequately funded.

B. RESIDENTIAL CUSTOMER CHARGE

Q. Do any of the other parties oppose the Company's proposed increase to its residential customer charge, citing purported adverse impacts on low-income customers?

A. Yes. As noted above, OCA witness Colton, CAUSE-PA witness Geller, and CEO witness Brady take that position.

Q. Could you please summarize OCA witness Colton's position?

A. Mr. Colton alleges that low-income customers would be disproportionately affected by the proposed increase. (OCA St. No. 4, p. 6.) He also claims that "at least 86% of UGI's estimated low-income customers are not paying a percentage of income-based CAP bill and, thus, are not insulated from the effects of the proposed increase in UGI's fixed monthly customer charge." (OCA St. No. 4, p. 8.) Relatedly, Mr. Colton asserts that CAP enrollees whose bills are based on average bills, which he maintains are more than half the Company's CAP participants, will be negatively affected by the increased customer charge. (OCA St. No. 4, pp. 8-9.)

Q. Is Mr. Colton correct that low-income customers would be disproportionately affected by the proposed increase in the residential customer charge or the Company's WNA proposal?

A. No, as explained by Mr. Taylor in UGI Gas St. No. 11-R, Mr. Colton's claim is without merit. In fact, Mr. Taylor demonstrates that the Company's proposed customer charge lowers the average bill for low-income and CAP customers. Also as explained by Mr. Taylor, the Company's proposed WNA mechanism will not adversely affect low-income customers. Accordingly, Mr. Colton's concerns are unfounded, and likewise, his basis for suggesting that an increase in LIURP funding is necessary as a result of the WNA is not appropriate.

Q. Mr. Colton also asserts that a very small percentage of low-income customers (7%) is protected against the proposed increase in the customer charge by participating in CAP. (OCA St. No. 4, p. 9.) Do you agree?

A. No. The Company's pending energy burden filing, if approved, will shift even more CAP participants from average bill to percent of income. Specifically, in that filing, the Company projects a 17% reduction to CAP customers on average bill, thus leaving only 38% of CAP customers on average bill. Moreover, the Company continues to promote and expand its CAP, as shown in UGI Gas Exhibit DVA-2R, which will continue to provide growth and expansion of CAP. Additionally, UGI Gas Exhibit DVA-5R sets forth data on the average consumption of low-income residential customers versus non-low-income residential customers. This data demonstrates that the Company's low-income customers do have a higher average use per customer, which establishes that a higher customer charge will generally benefit low-income customers.

Q. Do you agree with Mr. Colton that the increased customer charge "standing alone" will remove 95.4% of the total value of federal fuel assistance being delivered to low-income customers (OCA St. No. 4, pp. 9-10)?

A. No. Mr. Colton's portrayal that certain assistance dollars are somehow absorbed by the customer charge is inaccurate. Mr. Colton also incorrectly represents the number of customers that have received LIHEAP funding where Mr. Colton assumed that all 153,437 low-income customers on page 9, line 18 of his direct testimony received Federal Fuel assistance funding. This is simply incorrect. Also, as discussed by UGI Gas witness Mr. Taylor in his rebuttal testimony (UGI Gas St. No. 11-R), given low-income customers have higher usage, a higher customer charge is more beneficial than adding the increase into the volumetric charge for these customers. Mr. Colton's statement should be given no consideration.

Q. Mr. Colton also claims that UGI Gas has not considered how the proposed customer charge increase affects the cost-effectiveness of residential energy efficiency and conservation ("EE&C") measures. (OCA St. No. 4, p. 10.) Please respond.

A. Mr. Colton does not view the Company's rate design proposal correctly in the context of EE&C measures. When a customer is undertaking EE&C measures, the incremental cost of such measures must be measured against the incremental savings per unit of lower consumption. As the Company has proposed, the variable unit cost for residential customers will move up from $4.1104/Mcf to $4.9996/Mcf, thus the cost-effectiveness of any measures being considered by customers will actually increase when energy conservation measures are undertaken. Mr. Colton's claim is incorrect. (*See* UGI Gas Exhibit E, page 2 of 7.)

Q. CAUSE-PA witness Geller also opposes the Company's proposed residential customer charge and recommends that any rate increase be applied to the volumetric charge only. (CAUSE-PA St. No. 1, pp. 32-35.) Why does he disagree with the Company's proposal?

A. Mr. Geller claims that the proposed increase in the residential customer charge will adversely affect low-income customers and the Company's LIURP. (CAUSE-PA St. No. 1, pp. 32-35.)

Q. Similar to CAUSE-PA witness Geller, CEO witness Brady opposes any increase to the monthly customer charge. (CEO St. No. 1, pp. 4-6, 6-7, 12.) Why does he disagree with the Company's proposal?

A. Mr. Brady believes that the proposed increase to the residential customer charge will affect a customer's ability to conserve energy and that changes to funding for LIURP and other Universal Service Programs can help mitigate that effect. (CEO St. No. 1, pp. 4-6.) He also cites a statement by former Commissioner James Cawley in National Fuel Gas Distribution Corporation's ("National Fuel") 2006 base rate case as alleged support for his position. (CEO St. No. 1, pp. 6-7.)

Q. Do you agree with CAUSE-PA witness Geller and CEO witness Brady?

A. No. I would note the following: (1) Commissioner Cawley's statement was made at the outset of the National Fuel rate case regarding issues he asked the parties to address in the proceeding; it does not reflect a ruling on any specific customer charge proposal or the impact of any particular customer charge on conservation; (2) National Fuel requested a very substantial increase in the residential customer charge, i.e., $12 to $20.42 (or a 70% increase), a far greater percentage increase than that requested by UGI Gas in this proceeding; and (3) the customer charge issue in that case was part of larger rate design issues, in particular the use of declining block rates, which may discourage conservation (the large proposed increase in the customer charge was designed to reduce reliance on declining block rates). The Company does not have a declining block rate structure in Pennsylvania for residential customers. Therefore, Mr. Brady's reliance on Commissioner Cawley's 2006 statement is irrelevant to this proceeding.

Other UGI Gas witnesses, including Ms. Heppenstall (UGI Gas St. No. 10-R) and Mr. Taylor (UGI Gas St. No. 11-R), explain in detail why the Company's proposed residential monthly customer charge is just and reasonable. Further, as I explained previously, it is important to recognize that, in large part, low-income residential customers are either: (1) shielded from the impact of the increase to the residential monthly customer charge, or (2) not unreasonably burdened by a rate increase that increases a fixed charge versus a volumetric charge. And, depending on their usage, low-income residential customers can benefit from a higher customer charge as shown in the rebuttal testimony of Mr. Taylor (UGI Gas St. No. 11-R).

More specifically, CAP customers have the safety net of paying on a percentage of income basis and, in the lower income brackets, a minimum bill. In each instance, the customer is unaffected by the change in the fixed customer charge. A CAP customer would only be affected where the CAP customer pays an average monthly bill that is less than the percentage of income payment. In that situation, the customer's exposure is capped by the percentage of income payment or, in the case of high usage CAP customers, movement of more dollars into the customer charge might even benefit them. Moreover, as I noted earlier in my rebuttal testimony, the Company's pending Energy Burden filing is expected to reduce the number of CAP customers on average bill.

For non-CAP low-income customers, the impact of the higher monthly customer charge is mitigated by the fact that low-income customers generally average higher usage than the general residential customer population and, therefore, would suffer a greater impact if the Company had proposed a higher volumetric charge and a lower customer charge, as shown in UGI Gas Exhibit DVA-5R.

C. LATE FEES AND RECONNECTION FEES

Q. CAUSE-PA witness Geller asserts that the Company should no longer assess late fees and reconnection fees on low-income customers because, according to him, they unfairly penalize low-income customers that are unable to afford their bills. (CAUSE-PA St. No. 1, pp. 6, 37.) Please respond.

Q. I partially agree with Mr. Geller's position. To clarify, confirmed low-income customers who receive LIHEAP crisis grants or who are on CAP are not assessed late fees by the Company. The Company does assess reconnection fees to customers in order to best address the direct cost incurred by the Company when it sends personnel out to reconnect a customer's service. These fees do serve to facilitate customer engagement in order to prevent a disconnect from occurring in the first place. Mr. Geller does not address the cost impacts to the Company of not charging reconnect fees wherein the anticipated number of reconnections would increase. Moreover, as explained in UGI Gas witness Epler's rebuttal testimony (UGI Gas St. No. 8-R), to the extent the Commission would adopt Mr. Geller's recommendation, an adjustment to the Company's overall revenue requirement in this case would be required. Therefore, I maintain that Mr. Geller's recommendation should be denied.

V. ECONOMIC IMPACT OF COVID-19 ON LOW-INCOME CUSTOMERS

Q. OCA witness Colton recommends that the Company extend its "COVID responses" until the Company's next base rate case. (OCA St. No. 4, pp. 33-36.) What are those "COVID responses" referenced by Mr. Colton?

A. He recommends that the Company: (1) "commit to continuing to offer the extended payment plans as identified in the April 2021 Order in Docket M-2020-0319244"; (2) "reinstate its waiver of residential deposits for existing customers"; (3) "reinstate its expanded hardship grant income eligibility, along with its expanded maximum hardship grant"; and (4) "make an additional $1.0 million non-rate recoverable contribution to its hardship fund on an additional one-time basis." (OCA St. No. 4, p. 36.)

Q. What support does Mr. Colton provide for this recommendation?

A. Mr. Colton notes that although residential arrears have begun to decline in recent months, they have not returned to pre-COVID levels. Total dollars of residential arrearages and total dollars of arrearages aged 90-days old or older have declined in 2021 relative to 2020, but they remain higher than in 2019. Mr. Colton is recommending that the COVID-19 responses that UGI Gas had previously agreed to extend through the end of 2021 be continued until UGI Gas's next base rate case. In particular, he recommends the following:

- UGI Gas commit to continuing to offer the extended payment plans as identified in the Commission's April 2021 Order in Docket M-2020-0319244;
- UGI Gas reinstate its waiver of residential deposits for existing customers. The COVID-19 related payment difficulties of residential customers are not indicators of long-term payment risks. And the imposition of a cash security deposit remains an impediment to customers retiring the arrears that they have already incurred;
- UGI Gas reinstate its expanded hardship grant income eligibility, along with its expanded maximum hardship grant; and
- UGI Gas make an additional $1.0 million non-rate recoverable contribution to its hardship fund on an additional one-time basis.

Q. Do you agree with his recommendation?

A. No. The Company has complied with the Commission's emergency orders during COVID-19 and, in fact, added additional voluntary programs, such as the Emergency Relief Program as part of its 2020 base rate case at Docket Nos. R-2019-3015162, *et al*. I have also noted in my testimony the additional funding mechanisms that are available to customers who continue to struggle to pay their bills, along with the Company's efforts to continue expanding its USECP programs. Furthermore, bad debt continues to rise, and extending these provisions as Mr. Colton proposes would exacerbate that problem to the detriment of all ratepayers.

Q. Mr. Colton recommends that in a future rate case once the "economic crisis associated with the COVID-19 health pandemic has been reasonably resolved," the appropriate inter-class allocation of universal service costs should be addressed so that all customer classes are allocated those costs. (OCA St. No. 4, pp. 6, 43-47.) Please respond.

A. As Mr. Colton has indicated that he is not making any proposals as a part of this proceeding, the Company reserves its rights to respond to any reallocation proposal as a part of a future proceeding where this issue is raised for Commission resolution. However, I want to make it clear that to the extent Mr. Colton's testimony is, or could be, construed as a proposal to reallocate universal costs as a part of this proceeding, the Company opposes this proposal and submits that the OCA has not carried its burden of proof with respect to this proposal.

VI. <u>CONLUSION</u>

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

UGI Gas Exhibit DVA-1R

Daniel V. Adamo
Vice President Customer Relations

Work Experience

UGI Utilities, Inc., Reading, PA

August 2021 – Current	Vice President Customer Relations
August 2018 – July 2021	Director Customer Service
January – August 2018	Senior Manager Billing & Compliance
2016 – 2018	Functional Lead – UNITE Project
2015 – 2016	Manager Operations
2013 – 2015	Director Marketing (Programs and Strategy)
2011 – 2013	Business Development Director
2009 – 2011	Regional Marketing Manager
2007 - 2009	Manager Rates
2005 - 2007	Project Engineer Gas Supply
2004 – 2005	Project Engineer Key Accounts
2001 – 2004	Staff Engineer New Business
2000 – 2001	Customer Service Supervisor
1998-2000	Engineer 1

Previous Testimony

UGI Penn Natural Gas Purchased Gas Cost Filing: Docket No. R-2008-2039284 2009

UGI Penn Natural Gas Purchased Gas Cost Filing: Docket No. R-2009-2105904 2009

UGI Central Penn Gas Purchased Gas Cost Filing: Docket No. R-2009-2105909 2009

UGI Utilities – Gas Division Purchased Gas Cost Filing: Docket No. R-2009-2105911

UGI Growth Extension Tariff Pilot Programs Filing: Docket No. P-2013-2356232

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2018-3006814

UGI Utilities, Inc. Gas Division Base Rate Increase Filing: Docket No. R-2019-3015162

UGI Utilities, Inc. Electric Division Base Rate Increase Filing: Docket No. R-2021-3023618

Education

B.S. in Mechanical Engineering from Lehigh University, 1998

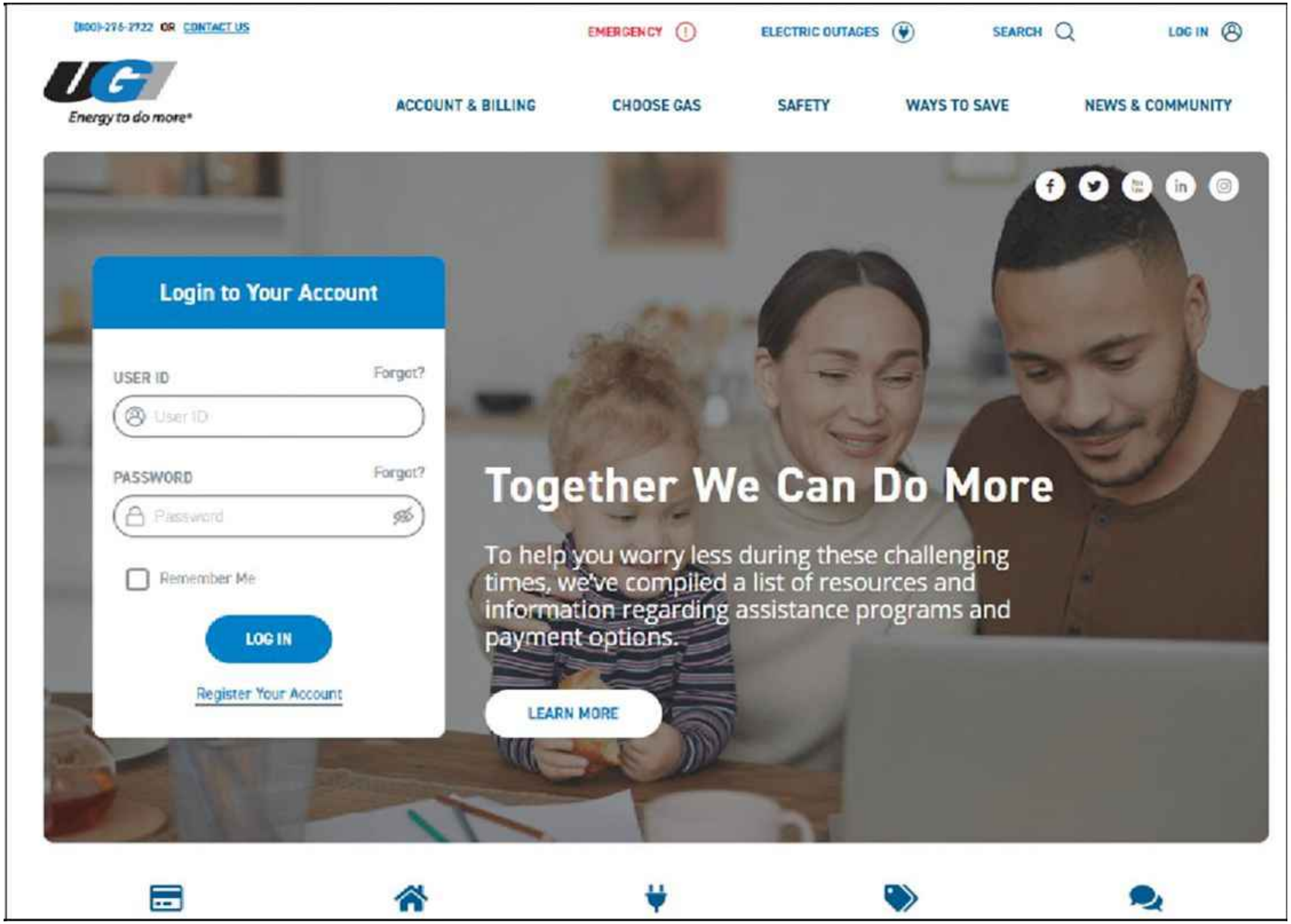
UGI Gas Exhibit DVA-2R

UGI Utilities, Inc.

COVID-19 Related Customer-Facing Communication Efforts

Energy to do more®

UGI.com Home Page – June 2020



Learn More destination is https://www.ugi.com/covid-19-response-plan/

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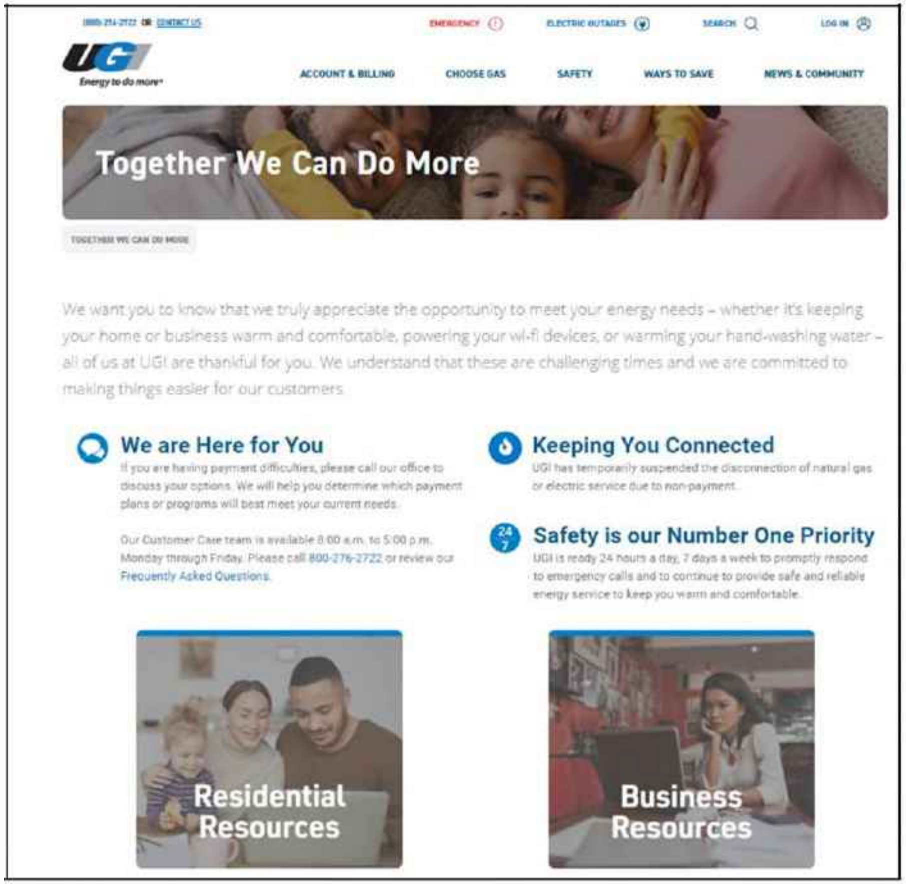
https://www.ugi.com/covid-19-response-plan/



ACCOUNT & BILLING | CHOOSE GAS | SAFETY | WAYS TO SAVE | NEWS & COMMUNITY

Together We Can Do More

We want you to know that we truly appreciate the opportunity to meet your energy needs – whether it's keeping your home or business warm and comfortable, powering your wi-fi devices, or warming your hand-washing water – all of us at UGI are thankful for you. We understand that these are challenging times and we are committed to making things easier for our customers.

We are Here for You

If you are having payment difficulties, please call our office to discuss your options. We will help you determine which payment plans or programs will best meet your current needs.

Our Customer Care team is available 8:00 a.m. to 5:00 p.m. Monday through Friday. Please call 800-276-2722 or review our Frequently Asked Questions.

Keeping You Connected

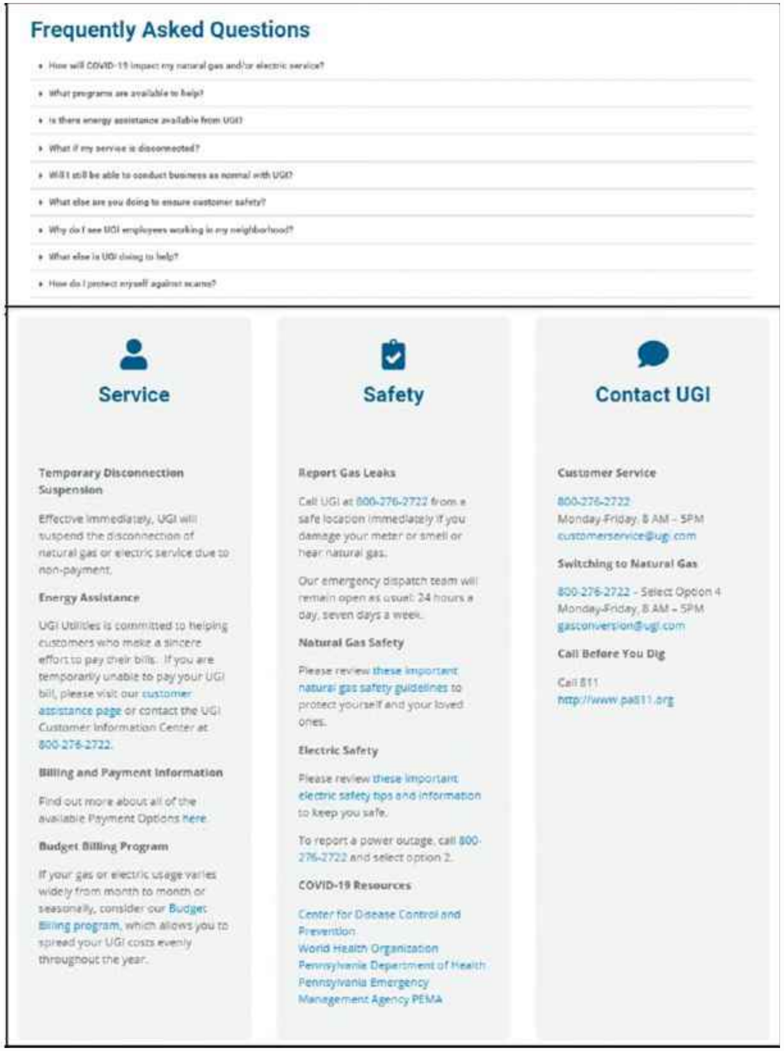
UGI has temporarily suspended the disconnection of natural gas or electric service due to non-payment.

Safety is our Number One Priority

UGI is ready 24 hours a day, 7 days a week to promptly respond to emergency calls and to continue to provide safe and reliable energy service to keep you warm and comfortable.

Residential Resources

Business Resources



Frequently Asked Questions

- How will COVID-19 impact my natural gas and/or electric service?
- What programs are available to help?
- Is there energy assistance available from UGI?
- What if my service is disconnected?
- Will I still be able to conduct business as normal with UGI?
- What else are you doing to ensure customer safety?
- Why do I see UGI employees working in my neighborhood?
- What else is UGI doing to help?
- How do I protect myself against scams?

Service

Temporary Disconnection Suspension

Effective immediately, UGI will suspend the disconnection of natural gas or electric service due to non-payment.

Energy Assistance

UGI Utilities is committed to helping customers who make a sincere effort to pay their bills. If you are temporarily unable to pay your UGI bill, please visit our customer assistance page or contact the UGI Customer Information Center at 800-276-2722.

Billing and Payment Information

Find out more about all of the available Payment Options here.

Budget Billing Program

If your gas or electric usage varies widely from month to month or seasonally, consider our Budget Billing program, which allows you to spread your UGI costs evenly throughout the year.

Safety

Report Gas Leaks

Call UGI at 800-276-2722 from a safe location immediately if you damage your meter or smell or hear natural gas.

Our emergency dispatch team will remain open as usual: 24 hours a day, seven days a week.

Natural Gas Safety

Please review these important natural gas safety guidelines to protect yourself and your loved ones.

Electric Safety

Please review these important electric safety tips and information to keep you safe.

To report a power outage, call 800-276-2722 and select option 2.

COVID-19 Resources

Center for Disease Control and Prevention
World Health Organization
Pennsylvania Department of Health
Pennsylvania Emergency Management Agency PEMA

Contact UGI

Customer Service

800-276-2722
Monday-Friday, 8 AM – 5PM
customerservice@ugi.com

Switching to Natural Gas

800-276-2722 - Select Option 4
Monday-Friday, 8 AM – 5PM
gasconversion@ugi.com

Call Before You Dig

Call 811
http://www.pa811.org

Energy to do more®

COVID Residential Resources Web Page

https://www.ugi.com/covid-19-response-plan/residential-resources/

(800) 276-2722 OR CONTACT US | EMERGENCY | ELECTRIC OUTAGES | SEARCH | LOG IN

Energy to do more®

ACCOUNT & BILLING | CHOOSE GAS | SAFETY | WAYS TO SAVE | NEWS & COMMUNITY

TOGETHER WE CAN DO MORE › COVID-19 RESIDENTIAL RESOURCES

UGI is committed to making things easier for our customers during these challenging times. To help you worry less, we've compiled the following list of resources and information regarding assistance programs and payment options.

Temporary Disconnection Suspension

Effective immediately, UGI will suspend the disconnection of natural gas or electric service due to non-payment.

Late Payment Fees Waived

UGI is providing bill credits for any late payment charges billed on or after March 25th, 2020 and until further notice. Bill credits will be applied on the next billing statement.

Billing and Payment Information

UGI offers a variety of payment options including:

- Creating an online account to pay online anytime
- Quick pay with a bank account with no fee
- Quick pay by credit card with no fee
- Send your payment by mail

View all of our options on our Payments & Billing page.

Budget Billing Program

If your gas or electric usage varies widely from month to month or seasonally, consider our Budget Billing program, which allows you to spread your UGI costs evenly throughout the year.

Additional Information

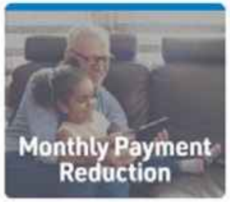
- IRS Economic Impact Payment Information Center
- COMPASS Need-Based Benefits Application
- Center for Disease Control and Prevention
- World Health Organization
- Pennsylvania Department of Health
- Pennsylvania Emergency Management Agency (PEMA)
- Pennsylvania 211: Get Connected. Get Help.™

Customer Assistance Programs to Help with Your Bill

As always, UGI offers many programs to assist customers in managing their energy costs and saving money. UGI is committed to helping customers who make a sincere effort to pay their bills. Our representatives can assist you by providing the information on a variety of energy assistance programs, making referrals to local agencies, applying for a grant from various fuel funds or establishing payment arrangements or an extension.

Existing assistance programs include:

Low-Income Home Energy Assistance Program (LIHEAP) offers FREE energy assistance grants for income-qualified customers. You do not have to have an unpaid bill to receive these grants.



Customer Assistance Program (CAP) offers a personalized monthly payment based on income, average bill, and past due debt forgiveness with on-time monthly payments. The difference between the CAP payment and actual usage bill may also be forgiven.

Operation Share Energy Fund is a community-based program that is funded by voluntary donations from UGI employees, UGI customers and concerned citizens. This fund provides energy assistance grants to qualified customers who experience difficultly paying their heating bills.

Contact UGI

UGI customers who are not eligible for low-income and fixed-income assistance but are experiencing trouble managing their energy costs should still consider contacting our Customer Care Center Monday through Friday from 8AM to 5PM at 800-276-2722. Our representatives can individually assist you and your family with additional options that may be available based on your account.

Energy to do more®

COVID-19 Business Resources Web Page

https://www.ugi.com/covid-19-response-plan/business-resources/

800-276-2722 OR CONTACT US | EMERGENCY | ELECTRIC OUTAGES | SEARCH | LOG IN

Energy to do more®

ACCOUNT & BILLING | CHOOSE GAS | SAFETY | WAYS TO SAVE | NEWS & COMMUNITY

TOGETHER WE CAN DO MORE > COVID-19 BUSINESS RESOURCES

Due to the COVID- 19 pandemic, many non-essential businesses have been closed until further notice. UGI understands that your business relies on its operation to maintain payroll, insurance, and utilities to name a few. Because of that, we're working with legislators, local Chambers of Commerce, and building associations to identify and communicate programs available to help business customers.

In addition, the UGI Business support team has been working diligently to gather information we know our business customers need. The information is from a variety of sources, and as you know, this content changes frequently. We recommend checking with your accountant, financial institution or one of the organizations referenced below if you have questions or concerns about the available assistance programs offered as a result of the Corona Aid, Relief and Economic Security (CARES) Act.

Support Agencies

- U.S. Small Business Administration
- SBA Local Assistance Agency Finder
- Chamber of Commerce:
  - PA Chamber COVID-19 information
  - Local Chamber Listing
- U.S. Senator Bob Casey Website
- U.S. Senator Pat Toomey Website
- U.S. Treasury
- PA Public Utility Commission COVID-19 information
- PA Department of Community & Economic Development

Contact UGI

Our Representatives are available Monday through Friday from 8AM - 5PM at 800-276-2722.

Coronavirus Aid, Relief and Economic Security (CARES) Act & Financial Assistance for Business

Economic Injury Disaster Loans (EIDL)

- Advance on loan up to $10,000
- Program provides working capital of up to $2 million; funds available within three days of successful application
- No need to repay the loan
- Economic Injury Disaster Emergency Loan Advance Website

Small Business Administration Debt Relief

- Provides a reprieve to small businesses as they overcome challenges created by the current health crisis
- SBA will pay principal and interest of new 7(a) loans issued prior to September 27, 2020
- SBA will pay principal and interest of current 7(a) loans for period of six months
- SBA Debt Relief Website

Small Business Administration Express Bridge

- Small businesses with an existing relationship with an SBA Express Lender may access up to $25,000 with less paperwork
- Businesses waiting for Economic Injury Disaster Loan disbursement may qualify for this loan
- Loan will be repaid in full or in part by proceeds from EIDL loan
- SBA Express Bridge Loans Website

Additional Tax-Related Help

- New Employee Retention Tax Credit is for employers who are closed, partially closed, or experiencing significant revenue losses as a result of COVID-19. Employers who receive a Paycheck Protection Program (PPP) loan are not eligible for the tax credit. Available for private employers, including non-profits, meeting specific eligibility criteria.
- Deferral of Payroll Taxes
- Expanded Unemployment Insurance
- Immediate Tax Credits for FFCRA Leave

Save Small Business Fund

- Provides $5,000 in short-term relief
- Employer criteria includes:
  - Between 3 and 20 Employees
  - Operating in one of a select group of economically vulnerable zip codes
  - Has been harmed financially by the COVID-19 pandemic
- Save Small Business Fund Website

Paycheck Protection Program (PPP)

- Provides loan forgiveness for retaining employees by temporarily expanding the traditional SBA 7(a) loan program
- For employer that has 500 workers or less (hospitality or food service employee count is per location)
- No collateral required
- Loans up to 250% of employer's average monthly payroll costs, with $10 million cap
- Loans will be forgiven if the employer maintains its workforce for the covered period February 15, 2020 to June 30, 2020
- Paycheck Protection Program Website

Large Commercial and Industrial Accounts

Commercial or industrial businesses with a rate category of DS, LFD, XD or IS that are experiencing financial strain as a direct result of COVID-19 should contact our Large Customer Billing group at LCBgroup@ugi.com or 866-615-0571 to discuss available payment options.

Major Accounts customers can access billing and meter worksheets, invoices, usage history, etc. on **UGI's Transportation Customer Portal**.

Energy to do more®

May 2020 Bill Insert (English One Side/Spanish Other Side)

Audience: All Customer Classes Receiving Paper Bills* (577,000)

At UGI, we are committed to making things easier for our customers during these challenging times.

We Are Here for You

If you are unable make a payment, please call our office to discuss your options. Our Customer Care team is available 8:00 a.m. to 5:00 p.m. Monday through Friday to help customers determine which payment plans or programs will best meet their current needs. **Please call 800-276-2722**.

Keeping You Connected

UGI has temporarily suspended the disconnection of natural gas or electric service due to non-payment.

Help When You Need It

UGI is providing bill credits for any late payment charges billed on or after March 25th, 2020 and until further notice. Bill credits will be applied on the next billing statement.

Our Customer Care team is here to help connect you with resources that will meet your needs, including access to help through our energy assistance programs, making referrals to local agencies, and eligibility for energy grant programs. Visit **www.ugi.com/customerassistance** for more information.

Safety is our Number One Priority

UGI is ready 24 hours a day, 7 days a week to promptly respond to emergency calls and to continue to provide safe and reliable energy service to keep you warm and comfortable.

Share the Warmth

Operation Share energy fund provides energy assistance grants to customers who have trouble paying their energy bills. 100% of every dollar donated goes directly to a local household in need. To join us in helping your neighbors, visit **www.ugi.com/operationshare**.

We know you have a lot to take care of, so let UGI take care of you.

For the latest information, please visit **www.ugi.com/together**.

En UGI, estamos comprometidos a facilitar las cosas para nuestros clientes durante estos tiempos difíciles.

Estamos aquí para usted

Si no puede realizar un pago, llame a nuestra oficina para analizar sus opciones. Nuestro equipo está disponible de Lunes a Viernes de 8:00 a.m. a 5 p.m. para ayudar a los clientes a determinar qué planes o programas de pago satisfarán mejor sus necesidades actuales. **Por favor llame al 800-276-2722.**

Manteniéndote conectado

UGI ha suspendido temporalmente la desconexión del servicios de gas natural o eléctricos por falta de pago.

Ayuda cuando lo necesitas

UGI está proporcionando créditos en la factura por los cargos por pagos atrasados facturados a partir del 25 de marzo de 2020 y hasta nuevo aviso. Los créditos de factura se aplicarán en el próximo estado de cuenta.

Nuestro equipo está aquí para ayudarlo a conectarse con los recursos que satisfarán sus necesidades, incluido el acceso a la ayuda a través de nuestros programas de asistencia energética, la derivación a agencias locales y la elegibilidad para programas de subvención energética. Visite **www.ugi.com/customerassistance** para más información.

La seguridad es nuestra política número uno

UGI está listo las 24 horas del día, los 7 días de la semana para responder rápidamente a las llamadas de emergencia y continuar brindando un servicio de energía seguro y confiable para mantenerlo cálido y cómodo.

Comparte el calor

El fondo de energía Operation Share proporciona subvenciones de asistencia energética a clientes que tienen problemas pagando sus facturas. El 100% de cada dólar donado va directamente a un hogar local necesitado. Para unirse a nosotros para ayudar a sus vecinos, visite **www.ugi.com/operationshare**.

Sabemos que tienes mucho que cuidar, así que deja que UGI se ocupe de ti.

Para obtener la información más reciente, visite **www.ugi.com/together**.

www.ugi.com/together destination is https://www.ugi.com/covid-19-response-plan/

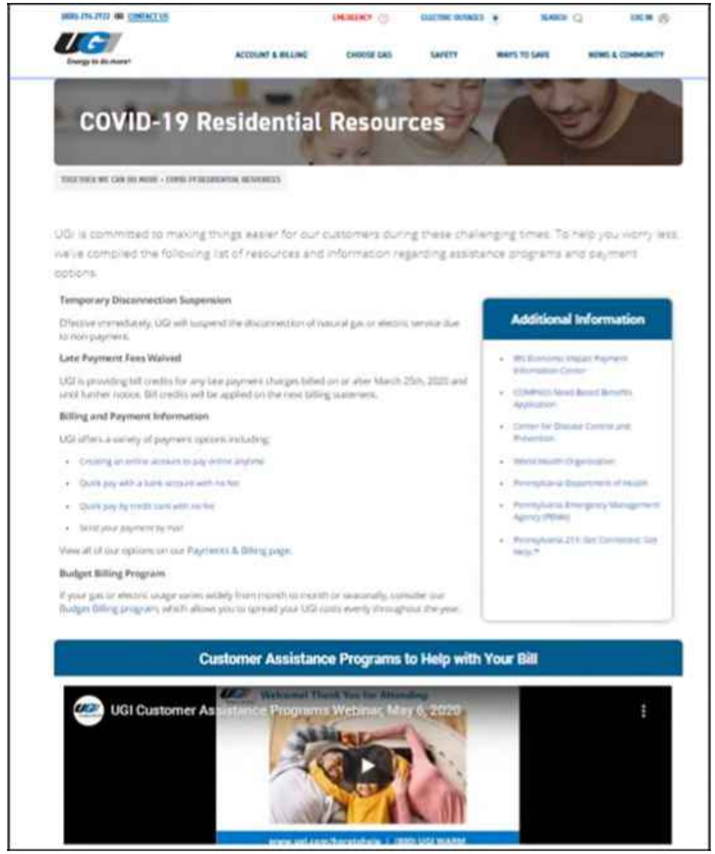
*Customers enrolled in eBill received email with "Together" content

May 4, 2020 - Customer Assistance Program Video Added to Customer Assistance Program Web Page

Results 5/4 – 6/1/2020	Video Link	Views
Pre-recorded webinar (English)	https://youtu.be/alwjDpWaOfA	238
Pre-recorded webinar (Spanish)	https://youtu.be/uuBNEa6toxE	75

Page Link: https://www.ugi.com/assistance-programs/

May 26, 2020 – Recorded Zoom Webinar Video Added to COVID-19 Residential Resources Web Page



Results 5/26 – 6/1/2020	Video Link	Views
Live (Zoom) webinar recording*	https://youtu.be/x8ViQiH3z3k	23

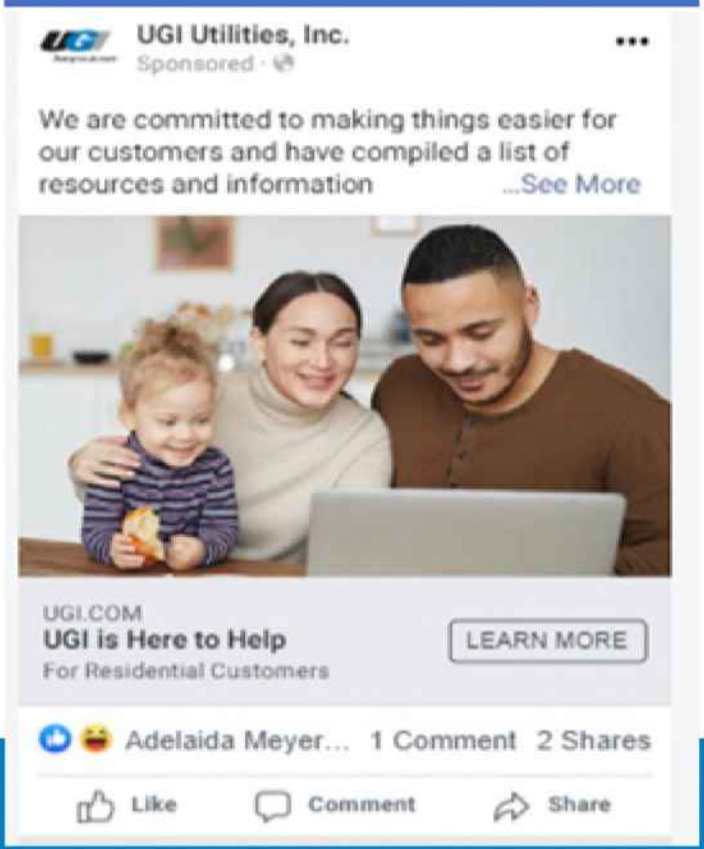
*Planned future communications to All Residential Natural Gas & Electric Customers will include a link to this video.

May 2020 - Facebook Ads

Results 5/5/2020 – 5/31/2020	Total
Impressions	551,67
Reach	137,088
Clicks	2,339

5/5/2020 through 5/18/2020

5/18/2020 to Current*



*June 1, 2020

Energy to do more®

March 18, 2020 – Email

Subject: “COVID-19 Virus Response: UGI Utilities is Here for You”

Audience: All Customer Classes

Delivered: 328,922

Energy to do more®

During the coronavirus (COVID-19) emergency, UGI remains committed to providing safe and reliable natural gas service to you 24 hours a day, 7 days a week.

We know that the daily changes brought on by COVID-19 present significant challenges to our customers and the communities we serve, but **our teams are ready and standing by to help in any way we can.**

First, we continue to closely monitor the situation. The health, safety, and productivity of our employees, customers and stakeholders is our top priority. Our efforts are focused on maintaining a safe and productive operation that continues to meet the needs of our customers. We would like you to know that significant steps we have taken to manage this situation include:

- Ensuring that essential personnel are in position and able to respond to our customers.
- Initiating an expanded work-from-home policy and communication system connectivity for most of our office employees.
- Implementing field operating safety measures to assure that all utility work can be completed in a safe manner for both our employees and customers. These measures include 'social distancing' protocols, use of additional personal protective equipment (PPE), and vehicle disinfecting stations.
- Developing and using prescreening questions for any work involving contact between field staff and customers.
- Suspending service disconnections for nonpayment until further notice.

UGI will review developments associated with the COVID-19 virus and will respond to changing circumstances as appropriate. We urge customers with specific questions to call 800-276-2722 to speak with a UGI customer service representative.

In the meantime, we are hopeful that you, your family, friends, colleagues, and communities remain safe and healthy.

Energy to do more®

March 20, 2020 – Email

Subject: “Important Message Re: Your Natural Gas Service Installation at %%Service Address Full Street%%”

Audience: Prospective Customers Converting to Natural Gas Who Have Signed Contracts But No Meter Set Yet

Delivered: 473

Energy to do more®

Dear Gerald Stephens,

In an effort to do our part to help prevent the further spread of COVID-19 and at the direction of Pennsylvania Governor Tom Wolf, UGI has temporarily suspended all non-emergency construction work. This suspension includes the construction work to connect homes and businesses to the natural gas main nearby. Please disregard this email if construction has already been completed at your property.

If you feel that the service connection to your home or business would be considered an emergency, i.e., no heating source available at your property, please respond to me at rmyers@ugi.com as soon as possible, and I will work with our Regional Operations Directors to request waivers from the Governor’s office in order for the work to be completed.

As the situation around COVID-19 evolves, UGI Utilities will continue to review the developments associated with the virus and will respond to changing circumstances as appropriate. For updates to the UGI COVID-19 Response Plan, please visit our website. UGI Utilities urges you to direct specific questions to our agents at 800-276-2722.

We thank you for your patience and understanding and look forward to serving you as a UGI natural gas customer in the near future.

Sincerely,

Ron Myers
UGI Representative
rmyers@ugi.com

March 24, 2020 – Email

Subject: "COVID-19 Response: Our Customer Spoke, We Listened"

Audience: All Customer Classes

Delivered: 329,130

Energy to do more

During the coronavirus (COVID-19) emergency, UGI remains committed to providing safe and reliable natural gas service to you 24 hours a day, 7 days a week.

UGI continues to provide reliable service to you while utilizing field operating safety measures such as 'social distancing', use of additional personal protective equipment (PPE), and vehicle disinfecting stations.

To further aid our customers during what is likely a disruptive time, UGI continues to suspend service disconnections for nonpayment.

Additionally, for all customers, UGI will provide a bill credit for any late payment charges billed on or after March 25th, 2020 until further notice. A bill credit for the amount of the late payment charge will be applied on your next billing statement.

If you are having trouble paying your bill, there are options available from UGI's customer care programs such as budget billing to help with averaging your bill evenly over the year. UGI's Customer Care Team is also available to answer your questions and concerns at 800-276-2722. Please follow the links below to learn more.

- **Login to your online account:** https://www.ugi.com
- **Register for an online account:** https://onlineaccount.ugi.com/portal/CustomerRegistration.aspx
- **Sign up for budget billing:** https://www.ugi.com/payments-billing/budget-billing/
- **Learn more about UGI's Customer Assistance Programs:** https://www.ugi.com/assistance-programs/

We know that the daily changes brought on by COVID-19 present significant challenges to our customers and the communities we serve, but our teams are ready and standing by to help in any way we can. We urge customers with specific questions to call 800-276-2722 to speak with a UGI Customer Service Representative.

In the meantime, we are hopeful that you, your family, friends, colleagues, and communities remain safe and healthy.

Energy to do more®

March 27, 2020 – Email

Subject: "COVID-19 Update for UGI's Major Accounts"

Audience: Major Accounts

Delivered: 1,673

Energy to do more®

To UGI's Valued Major Account Customers:

During these trying times, UGI would like to take this opportunity to remind you of our continued commitment to providing safe and reliable service 24 hours a day, 7 days a week. Specifically, for our Major Account customers, we wanted to highlight some important notes, resources and reminders:

- Information regarding UGI's overall business continuity plan and FAQs pertaining to COVID-19 can be found here: https://www.ugi.com/covid-19-response-plan
- UGI's Transportation Customer Portal provides customers access to billing and meter worksheets, invoices, usage history, etc. and can be found here: http://www.ugi.com/transportation
- UGI has temporarily ceased shut-off activity and is waiving late payment charges (a credit will be applied on your next billing statement) until further notice.
- **UGI reminds all customers to continue to work closely with their suppliers to balance deliveries with usage.**
- **UGI encourages you to keep an open line of communication with us on any significant changes to your use of natural gas.**
  - UGI's Large Customer Billing team is fully dedicated to our Key Accounts Customer base. We're closely monitoring the LCBgroup@ugi.com inbox daily. Additionally, the team is responding to voicemails left at 866 615 0571 (to be returned within 24-48 business hours). Further, the LCB team can assist with setting up auto-payment options.
  - As an additional resource, please route non-billing related updates or questions to your local Relationship Manager:

Steve Bareuther	Joseph Bauman	Rhiannon Hazzard	Andrew Rohrer
SERVES HARRISBURG EAST SHORE, LANCASTER AND LEBANON AREA	SERVES SCRANTON, WILKES-BARRE, POCONOS AND POTTSVILLE AREA	SERVES READING, ALLENTOWN AND EASTON AREA	SERVES HARRISBURG WEST SHORE, LEWISBURG, WILLIAMSPORT AND LOCK HAVEN AREA
610-736-5446	570-829-8901	610-796-3439	570-701-5010

Energy to do more®

April 23, 2020 - Email

Subject: “A Thank You from UGI”

Audience: All Residential Natural Gas & Electric Customers

Delivered: 313,833

Energy to do more®

thank you!

Recently, there has been so much uncertainty in our lives. **One thing that remains certain is how grateful we are to have you as a customer.** We want you to know that we truly appreciate the opportunity to meet your energy needs – whether it's keeping your home warm and comfortable, drying your seemingly endless loads of laundry or warming your hand-washing water – **all of us at UGI are thankful for you.**

If you've reached out to our Customer Care Team and shared your story, **thank you.** If you've helped your neighbors through a donation to our Operation Share Energy Fund, **thank you.** If you've paid your recent energy bill, **thank you.** If you've called 811 before starting a landscaping project, **thank you.**

And to our customers, friends and neighbors on the front lines of the COVID-19 pandemic going to work every day to help the rest of us in any capacity, **a special thank you**, we truly appreciate your selflessness, courage and dedication during this crisis.

Finally, if there is anything we can do to support you, please contact us at 800-276-2722 or visit our website for resources to assist you during this time. Now, and always, we are here for you.

Sincerely,

Your Friends in Customer Care at UGI Utilities

COVID-19 RESPONSE PLAN | GAS SAFETY | ELECTRIC SAFETY

Energy to do more®

April 23, 2020 - Email

Subject: “A Thank You from UGI”

Audience: All Non-Residential Natural Gas & Electric Customers

Delivered: 18,874

Energy to do more®

thank you!

Recently, there has been so much uncertainty in our lives. **One thing that remains certain is how grateful we are to have you as a customer.** We want you to know that we truly appreciate the opportunity to meet your energy needs – whether it's keeping your business warm and comfortable, warming your hand-washing water or powering your equipment – **all of us at UGI are thankful for you.**

We recognize it's been a tough few weeks, especially for our business customers. Please know that we are standing by and ready to support you now, and when your doors reopen. And to those on the front lines of the COVID-19 pandemic going to work every day to help the rest of us in any capacity, **a special thank you**, we truly appreciate your selflessness, courage and dedication during this crisis.

If there is anything we can do to support you, please contact us at 800-276-2722 or visit our website for resources to assist you during this time. **Now, and always, we are here for you.**

Sincerely,

Your Friends in Customer Care at UGI Utilities

COVID-19 RESPONSE PLAN | GAS SAFETY | ELECTRIC SAFETY

Energy to do more®

May 2, 2020 - Email

Subject: "Join Us for a Webinar on Assistance Programs You May Be Eligible For"

Audience: Residential Low Income Natural Gas & Electric Customers

Delivered: 16,706

Do you, or someone you know, need help paying your UGI utility bills?

UGI is committed to helping customers who make a sincere effort to pay their bills. Our representatives will be holding a live webinar where they will provide information on a variety of energy assistance programs. There will be a question and answer segment following the presentation.

Free Customer Assistance Programs Webinar
Join Online or by Phone this Wednesday, May 6, 1pm – 2pm

REGISTER TO ATTEND & PRE-SUBMIT YOUR QUESTIONS

During the webinar, our Customer Outreach Team sharing information about the following assistance programs:

Low Income Home Energy Assistance Program (LIHEAP)

LIHEAP offers energy assistance grants to income-qualified customers. Additional money is available in emergency situations where a customer could be be in danger of losing their heat.

Customer Assistance Program (CAP)

UGI provides CAP participants with a personalized, monthly payment amount based on income, household size and average bill.

Low Income Usage Reduction Program (LIURP)

LIURP provides high-usage, low-income households with home improvements to help reduce their energy bills. It provides long-term, cost-effective energy conservation services and equipment to low-income households with higher than average usage at no cost.

Operation Share Energy Fund

This community-based program provides energy assistance grants funded by voluntary donations from UGI employees, UGI customers and concerned citizens. In addition, UGI provides a corporate donation to help fund the program.

PAY BILL ONLINE

START/STOP SERVICE

ENERGY SAVINGS

Energy to do more®

Webinar Registration Email Response

Subject: “Zoom Webinar Registration Confirmation”

Audience: Any Customer Completing Zoom Webinar Registration Form

Delivered: 158

Energy to do more®

Dear Michelle,

Thank you for registering to attend the UGI Utilities Free Customer Assistance Programs Webinar.

On Wednesday, May 6 at 1pm, please click the link or dial the number below to join the webinar.

https://UGIcorp.zoom.us/j/94980589151

1-312-626-6799, ID: 94980589151#

NEW TO ZOOM?

PC or Mac:
Click the Zoom link provided above, and run software when prompted. Select "join with computer audio" or click the phone call tab to dial in via one of the numbers provided.

Mobile phone, iPad or tablet:
Download the free Zoom app from the iTunes or GooglePlay store; then tap on the link above.

Landline or Mobile phone:
Dial the telephone number provided above and enter the Meeting ID when prompted.

If you have any questions, please contact us Monday – Friday 8am – 5pm at 1-800-UGI-WARM.

Sincerely,

UGI Utilities

Energy to do more®

May 6, 2020 - Email

Subject: "Reminder to Join Us Later today for Our Free Customer Assistance Program Webinar"

Audience: Any Customer that Registered for the Zoom Webinar

Delivered: 158

Energy to do more®

Dear Michelle,

We are looking forward to you joining us this afternoon for our Free Customer Assistance Programs Webinar. Our Customer Outreach team will be providing information on a variety of energy assistance programs.

Today at 1pm, please click the link or dial the number below to join the webinar.

https://UGIcorp.zoom.us/j/94980589151

US: +1-312-626-6799, ID: 94980589151#

NEW TO ZOOM?

PC or Mac:
Click the Zoom link provided above, and run software when prompted. Select "join with computer audio" or click the phone call tab to dial in via one of the numbers provided.

Mobile phone, iPad or tablet:
Download the free Zoom app from the iTunes or GooglePlay store; then tap on the link above.

Landline or Mobile phone:
Dial the telephone number provided above and enter the Meeting ID when prompted.

If you have any questions, please contact us Monday – Friday 8am – 5pm at 1-800-UGI-WARM.

Sincerely,

UGI Utilities

May 4, 2020 - Email

Subject: "Important Message Re: Your Natural Gas Service Installation at %%Service Address Full Street%%"

Audience: Prospective Customers Converting to Natural Gas Who Have Signed Contracts But No Meter Set Yet

Delivered: 417

Dear Mark Leiss,

We hope this message finds you and yours safe and well! I'm writing to provide an update about construction to connect your property to the natural gas main nearby. As mentioned in my prior message, UGI suspended all non-emergency construction work to keep our customers, employees and communities safe, as directed by Governor Tom Wolf. As a result, we have developed a significant backlog of new construction work. We have been carefully monitoring guidelines provided by the Federal and Commonwealth Governments and have begun to prepare for when construction activities can resume. There are several challenges to overcome, including securing permits from local municipal offices, many of which were also closed. Please know that we are eager to serve you and are working very hard to schedule your installation as soon as possible. I, or another representative from UGI, will be reaching out to you as soon as we have details to share about your specific project.

If construction has already been completed at your property, please disregard this message with our apologies.

We appreciate your patience and look forward to serving you in the near future! Thank you again for choosing UGI Utilities.

Sincerely,

Ron Myers
UGI Representative
rmyers@ugi.com

Energy to do more®

May 4, 2020 - Email

Subject: “UGI Connections for Your Home – May 2020”

Audience: Residential Low Income Natural Gas & Electric Customers

Delivered: 50,000

Energy to do more®

Join Us for a Free Webinar on Assistance Programs

Our representatives will be holding a live webinar on **May 6th from 1pm to 2pm** where they will provide information on a variety of energy assistance programs. There will be a question and answer segment following the presentation. Register to attend and submit your questions.

As a result of the coronavirus (COVID-19) emergency,UGI provided $60,000 of financial support to local food banks serving communities in its service area to assist them in meeting the increased need. These donations are part of an initiative conducted by the various companies that are part of UGI Corporation to provide support to the many communities they serve.

"The COVID-19 crisis continues to evolve and it is clearly having a financial impact on millions of Pennsylvanians," Joe Arthur, Executive Director of the Central Pennsylvania Food Bank, said. "Over the past week, some of our partner agencies have already reported triple the amount of clients. Life-sustaining donations like the one provided by UGI will help us feed these families in need and help us provide 120,000 additional meals during this time. We are very grateful for UGI's support." UGI provided donations to the following food banks assisting residents in in communities within the Company's service territory:

- The Central Pennsylvania Food Bank received $20,000. The Central Pennsylvania Food Bank works to reduce hunger in 27 counties across central Pennsylvania.
- The Commission on Economic Opportunity received $15,000 in support of the Weinberg Northeast Regional Food Bank. The Food Bank serves Lackawanna, Luzerne, Susquehanna, and Wyoming Counties.
- The Community Action Committee of the Lehigh Valley received $10,000 in support of the Second Harvest Food Bank of the Lehigh Valley and Northeast Pennsylvania. Second Harvest Food Bank serves 200 agencies in Carbon, Lehigh, Monroe, Northampton, Pike, and Wayne Counties.
- Helping Harvest received $10,000. Helping Harvest distributes food to more than 300 charitable food program partners in Berks and Schuylkill Counties.
- The Second Harvest Food Bank of Northwest Pennsylvania received $5,000. Second Harvest serves 11 counties in northwest Pennsylvania.

We Are Here for You. If you are unable make a payment, please call our office to discuss your options. Our Customer Care team is available Monday-Friday, 8am – 5pm to help customers determine which payment plans or programs will best meet their current needs. For more information on how we can help, visit our website or call 800-276-2722 .

Energy to do more®

May 12, 2020 - Email

Subject: “UGI is Here to Help”

Audience: All Customer Classes

Delivered: 331,034

At UGI, we are committed to making things easier for our customers during these challenging times.

We are Here for You

If you are unable make a payment, please call our office to discuss your options. Our Customer Care team is available 8:00 a.m. to 5:00 p.m. Monday through Friday to help customers determine which payment plans or programs will best meet their current needs. **Please call** 800-276-2722.

Keeping You Connected

UGI has temporarily suspended the disconnection of natural gas or electric service due to non-payment.

Help When You Need It

UGI is providing bill credits for any late payment charges billed on or after March 25th, 2020 and until further notice. Bill credits will be applied on the next billing statement.

Our Customer Care team is here to help connect you with resources that will meet your needs, including access to help through our energy assistance programs, making referrals to local agencies, and eligibility for energy grant programs. Visit our website for more information.

Safety is our Number One Priority

UGI is ready 24 hours a day, 7 days a week to promptly respond to emergency calls and to continue to provide safe and reliable energy service to keep you warm and comfortable.

Share the Warmth

Operation Share energy fund provides energy assistance grants to customers who have trouble paying their energy bills. 100% of every dollar donated goes directly to a local household in need. To join us in helping your neighbors, visit our website.

We know you have a lot to take care of, so let UGI take care of you.

Energy to do more®

May 27, 2020 - Email

Subject: "Important Info Regarding Your Account Management"

Audience: Current Residential Natural Gas & Electric Customers Not Enrolled in AutoPay or Electronic Billing

Delivered: 55,796

Dear Terry,

As we navigate this unprecedented time, UGI's top priority is the safety and well-being of our customers and the communities we serve.

UGI is committed to helping provide support and solutions you may need as developments unfold. You can always stay up to date on our response to COVID-19 at https://www.ugi.com/covid-19-response-plan/.

Create an Online Account for Easy Account Management

For your convenience, we highly recommend managing your account digitally. When you create a UGI Online Account, you'll be able to access your bills and receive bill notifications via email, view your energy usage, update profile and contact settings, pay your bill, and more.

To create your Online Account, all you need is your UGI account number (12 digit number starting with a "4") and your service address zip code. Create online account now.

Enroll in AutoPay for No Hassle, On-Time Payments

When you enroll in the UGI AutoPay program, your UGI account balance will be automatically deducted from your checking or savings account on the day your bill is due.

Enroll for free after you create your UGI Online Account. Learn more.

Call Us. We're Here to Help.

Our Customer Care Center is staffed Monday through Friday from 8 am to 5 pm with helpful representatives who are ready to assist you. If you have questions about the above programs, or have concerns about your account, please call us at 800-276-2722.

Energy to do more®

May 27, 2020 - Email

Subject: "Important Info Regarding Your Account Management"

Audience: Past Due Residential Natural Gas & Electric Customers Not Enrolled in AutoPay or Electronic Billing

Delivered: 28,942

Dear Terry,

We know our customers have a lot on their minds right now and we want you to know that we are committed to making things easier for you. We wanted to share some digital payment options that may simplify your life now, and in the future.

Pay by Credit Card Without a Fee

Did you know that you can pay your bill with a credit care without a fee? Pay with a credit card here.

Create an Online Account for Easy Account Management

For your convenience, we highly recommend managing your account digitally. When you create a UGI Online Account, you'll be able to access your bills and receive bill notifications via email, view your energy usage, update profile and contact settings, pay your bill, and more.

To create your Online Account, all you need is your UGI account number (12 digit number starting with a "4") and your service address zip code. Create online account now.

Call Us. We're Here to Help.

Our Customer Care Center is staffed Monday through Friday from 8 am to 5 pm with helpful representatives who are ready to assist you. If you have questions about the above programs, or have concerns about your account, please call us at 800-276-2722.

Energy to do more®

May 28, 2020 - Email

Subject: "Thank You for Registering for Our Customer Assistance Webinar"

Audience: Customers That Registered for May 6 Zoom Webinar

Delivered: 158

Energy to do more®

Dear %%=Propercase(Name)=%%,

You recently registered for the UGI Utilities Customer Assistance Programs Webinar that was held on Wednesday, May 6. In case you were unable to attend, we have released a recording of the webinar, which contains answers to many of the questions asked prior to and during the webinar. View the recorded webinar here.

Our UGI representatives may have already contacted you to review your account. If so, and you have received all of the answers you need, great! Please feel free to share the link above with others you feel may benefit.

If you still have questions about your UGI account and/or the customer assistance programs that may be available to assist you, please do not hesitate to contact us. Our representatives are available Monday through Friday from 8:00 am to 5:00 pm at 1-800-UGI-WARM.

Thank you for the opportunity to serve you.

Sincerely,

The UGI Utilities Customer Care Team

Video Link appears at https://www.ugi.com/covid-19-response-plan/residential-resources/

Energy to do more®

June 1, 2020- Email

Subject: “$100 LIHEAP Crisis Grant Has Been Applied to Your UGI Account”

Audience: LIHEAP Supplemental $100 Grant Recipients

Delivered: 1,999

Energy to do more®

Dear Joseph,

On May 18, 2020, the LIHEAP program re-opened and additional Crisis funding was made available due to the COVID-19 pandemic.

Your Account Qualified for a $100 Supplemental LIHEAP Benefit

UGI has received a supplemental amount of $100 in LIHEAP Crisis funding which has been applied to your account as of May 27, 2020. This $100 supplemental benefit counts towards your maximum Crisis benefit amount.

Even with this automatic grant from the Department of Human Services you may be eligible for an additional $100 or more in Crisis Grant from LIHEAP. If you received a delinquent notice since April 9, 2020 and have not reached the $800 Crisis Grant maximum, UGI will automatically request the additional amount from the Department of Human Services on your behalf, and automatically apply it to your UGI account upon receipt.

Have Questions? We're Here to Help!

Please reach out to us at 800-UGI-WARM. Customer Service Representatives are available Monday through Friday from 8:00am until 5:00pm.

Thank you for the opportunity to continue to serve you.

The UGI Utilities Customer Care Team

COVID-19 RESPONSE PLAN | GAS SAFETY | ELECTRIC SAFETY

June 1, 2020 - Direct Mail

Subject: "$100 LIHEAP Crisis Grant Has Been Applied to Your UGI Account"

Audience: LIHEAP Supplemental $100 Grant Recipients

Delivered: 797

Address Block

Dear First Name

On May 18, 2020, the LIHEAP program re-opened and additional Crisis funding was made available due to the COVID-19 pandemic.

Your Account Qualified for a $100 Supplemental LIHEAP Benefit

UGI has received a supplemental amount of $100 in LIHEAP Crisis funding which has been applied to your account as of May 29, 2020. This $100 supplemental benefit counts towards your maximum Crisis benefit amount.

Even with this automatic grant from the Department of Human Services you may be eligible for an additional $100 or more in Crisis grant funds from LIHEAP. If you received a delinquent notice since April 9, 2020 and have not reached the $800 Crisis Grant maximum, UGI will automatically request the additional amount from the Department of Human Services on your behalf, and automatically apply it to your UGI account upon receipt.

Have Questions? We're Here to Help!

Please reach out to us at (800) UGI WARM. Customer Service Representatives are available Monday through Friday from 8:00 AM until 5:00 PM.

Thank you for the opportunity to continue to serve you.

The UGI Utilities Customer Care Team

Direct Mail Postcard – June 2020

Audience: Residential Natural Gas & Electric Customers without Email Address (Mailed to 250,623 Customers)

www.ugi.com/domore destination is https://www.ugi.com/covid-19-response-plan/
www.ugi.com/homeresources destination is https://www.ugi.com/covid-19-response-plan/residential-resources

Direct Mail Postcard – June 2020

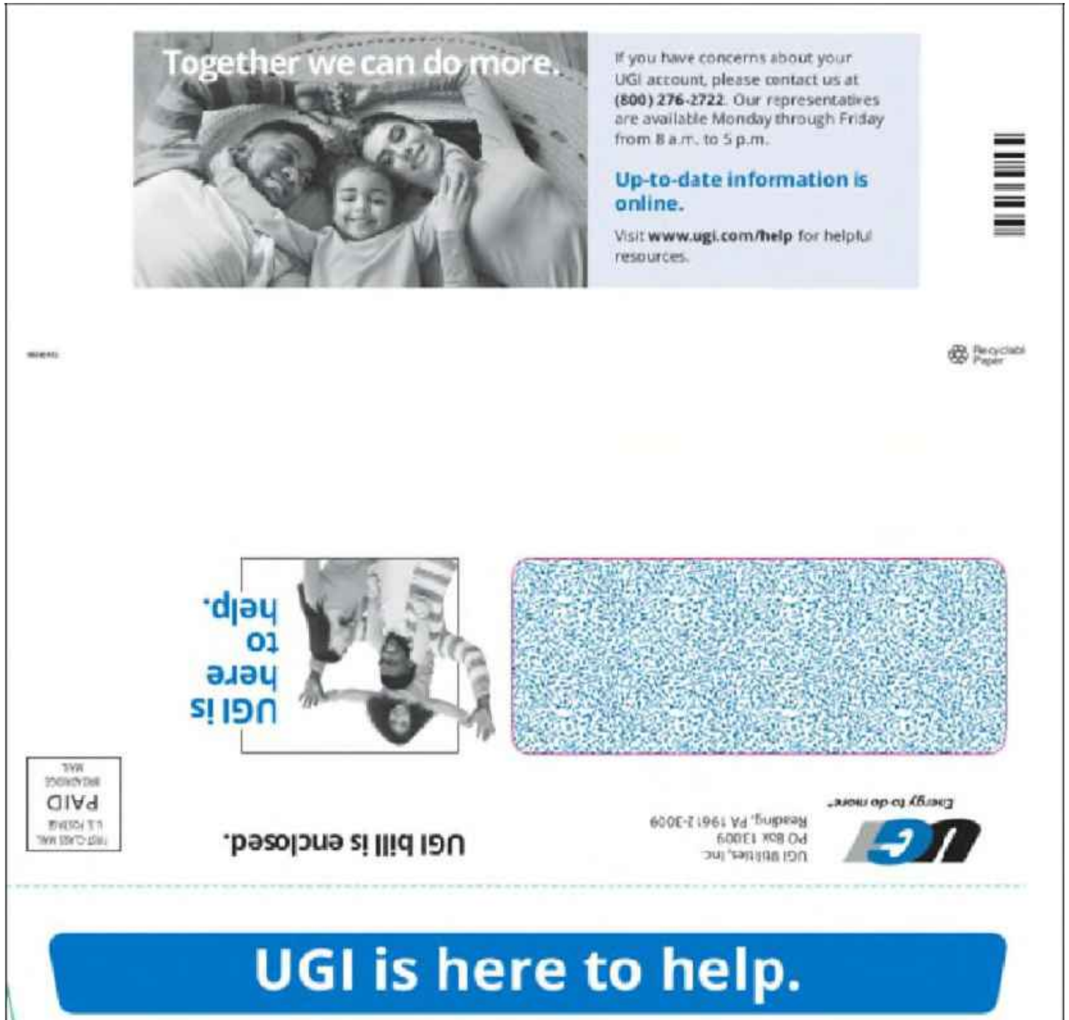
Audience: Small Commercial Customers (Rate N, NT) without Email Address (Mailed to 26,862 Customers)

www.ugi.com/domore destination is https://www.ugi.com/covid-19-response-plan/
www.ugi.com/businessresources destination is https://www.ugi.com/covid-19-response-plan/business-resources/

Energy to do more®

Bill Send Envelope July 2020

Audience: All Customers Receiving a Bill in July 2020



Energy to do more®

Direct Mail Postcard – November 2020

Audience: Residential ERP Non-Responders

ERP Phase 2 Pre-Enroll – Email – February 2021

Audience: Residential Natural Gas & Electric Customers

Energy to do more®

Dear Erik Hansen,

We know the last year has been both stressful and challenging. We continue to be committed to making things easier for our customers. That's why we're pleased to announce we're now accepting applications for the UGI Emergency Relief Program, to help those having a difficult time paying their energy bills as a result of the COVID-19 Pandemic. This program has received approval from the Pennsylvania Public Utility Commission (PUC). Enroll now!

Note: If you participated in the 2020 Emergency Relief Program and continue to experience difficulties paying your bill, you are still able to apply now!

What is the UGI Emergency Relief Program?

The program consists of two components to help qualifying customers with their outstanding energy bills during the COVID-19 Pandemic:

- **Installment Plan**
  Enrollment in this plan will allow you to spread your outstanding UGI balance over a period of time. This will provide extra time to catch up on your outstanding balance.
- **Grant**
  A one-time grant of up to $400 for amounts billed for service after March 2020 is available to customers who are eligible.

UGI will not terminate your service if you follow program guidelines and make payments on or before each month's due date.

How do I qualify for the UGI Emergency Relief Program?

- You, or someone in your household received unemployment benefits on or after March 13, 2020; or
- You, or a member of your household, are eligible for or have received the maximum for the Federal COVID-19 Relief Check (Federal CARES Act Economic Impact Payment) benefit in 2020 or 2021

How do I pre-enroll in the UGI Emergency Relief Program?

There are two ways to enroll:

- Enroll Online Today
  Complete our short online application form .
- **Call** 800-276-2722
  Our Customer Service Representatives are available Monday through Friday from 8:00 am to 5:00 pm and will be able to assist you with enrolling in the program. *(Si prefiere recibir esta información en español, favor de llamarnos.)*

When you enroll, please reference your account number **421003313630** with a service address of 9 Darte Ave Fl 1 in Carbondale.

Thank you for allowing us the opportunity to serve you!

UGI Customer Service Team

COVID-19 RESPONSE PLAN | GAS SAFETY | ELECTRIC SAFETY

Energy to do more®

ERP Phase 2 Pre-Enroll - Direct Mail – February 2021

Audience: Residential Natural Gas & Electric Customers

Dear (Business Partner),

We know the last year has been both stressful and challenging. We continue to be committed to making things easier for our customers. That's why we're pleased to announce Phase 2 of the UGI Emergency Relief Program, to help those having a difficult time paying their energy bills as a result of the COVID-19 Pandemic. This program is currently pending approval with the Pennsylvania Public Utility Commission (PUC). We expect the program to be approved late Winter 2021. UGI is urging qualified customers to pre-enroll now!

Note: If you participated in Phase 1 of the Emergency Relief Program and continue to experience difficulties paying your bill, you are still able to pre-enroll for Phase 2!

What is the UGI Emergency Relief Program?
The program consists of two components to help qualifying customers with their outstanding energy bills during the COVID-19 Pandemic:

Installment Plan
Enrollment in this plan will allow you to spread your outstanding UGI balance over a period of time. This will allow extra time to catch up on your outstanding balance.

Grant
A one-time grant of up to $400 for amounts billed for service after March 2020 is available to customers who are eligible.

UGI will not terminate your service if you follow program guidelines and make payments on or before each month's due date. Since the program will not be implemented until early Spring 2021, customers are **encouraged to continue making reasonable monthly payments** until the plan begins to help keep your account balance and future payments more manageable.

Continued on back

How do I qualify for the Emergency Relief Program?

- You, or someone in your household, filed for or received unemployment benefits on or after March 13, 2020; or
- You, or a member of your household, are eligible for or have received the maximum for the Federal COVID-19 Relief Check (Federal CARES Act Economic Impact Payment) benefit in 2020 or 2021

How do I pre-enroll in the UGI Emergency Relief Program?

There are two ways to pre-enroll:

- **Online at www.ugi.com/reliefnow**
  Complete our short pre-enrollment form. We will contact you after the program is approved and applications are being accepted.
- **Call (800) 276-2722**
  Our Customer Service Representatives are available Monday through Friday from 8:00 am to 5:00 pm and will be able to assist you with pre-enrolling in the program. *(Si prefiere recibir esta información en español, favor de llamarnos.)*

Thank you for allowing us the opportunity to serve you!

UGI Customer Service Team

ERAP-Related Communications & Audience

March 2021 - Current

Emergency Rental Assistance Program Solicitations March 2021 – Customized Email

Audience: Renters

Energy to do more®

Dear Chris Bormann,

We know the last few months have been both stressful and challenging. We're committed to making things easier for our customers. You may qualify for the Emergency Rental Assistance Program. (If you're not a renter, please visit www.ugi.com/reliefnow to learn about other assistance that may be available to you.)

The United States Treasury recently approved this program to assist renters that are struggling financially due to the COVID-19 pandemic. **Benefits include assistance with utility accounts (electric, natural gas), water bills and rent.** Utility and rent incurred from March 2020 through present will be considered.

How do I qualify for the Emergency Rental Assistance Program?

- One or more individuals in your household has qualified for unemployment benefits, or experienced a reduction in household income, incurred significant costs, or experienced other financial hardship due, directly or indirectly, to the pandemic
- One or more individuals demonstrate a risk of experiencing homelessness or housing instability, which may include a past due utility or rent notice or eviction notice, unsafe or unhealthy living conditions, or any other evidence of such risk
- The household income does not exceed 80% of the median income for Lackawanna County; income is based on total income for calendar year 2020, or confirmation of monthly income at the time of application

Learn More **about qualifications for benefits available in Lackawanna County**

How do I enroll in the Emergency Rental Assistance Program?

Each county has a different application process, and benefits may vary by county. Lackawanna County is accepting only paper applications at this time. Residents of Lackawanna County can download the paper application and review eligibility requirements using the link below.

- Apply Online

When you apply, please reference your UGI account number **411005848782** with a service address of 629 Moltke Ave in Scranton.

UGI Customer Service Team

COVID-19 RESPONSE PLAN | GAS SAFETY | ELECTRIC SAFETY

Emergency Rental Assistance Program Solicitations March 2021 – Customized Direct Mail

Audience: Renters

We know the last few months have been both stressful and challenging. We're committed to making things easier for our customers. You may qualify for the Emergency Rental Assistance Program. (If you're not a renter, please visit www.ugi.com/reliefnow to learn about other assistance that may be available to you.)

The United States Treasury recently approved this program to assist renters that are struggling financially due to the COVID-19 pandemic. Benefits include assistance with utility accounts (electric, natural gas), water bills and rent. Utility and rent incurred from March 2020 through present will be considered.

How do I qualify for the Emergency Rental Assistance Program?

- One or more individuals in your household has qualified for unemployment benefits, or experienced a reduction in household income, incurred significant costs, or experienced other financial hardship due, directly or indirectly, to the pandemic
- One or more individuals demonstrate a risk of experiencing homelessness or housing instability, which may include a past due utility or rent notice or eviction notice, unsafe or unhealthy living conditions, or any other evidence of such risk
- The household income does not exceed 80% of the average median income (AMI) for Lehigh County; income is based on total income for calendar year 2020, or confirmation of monthly income at the time of application

80% Average Median Income (AMI) for Lehigh County

1 Person	2 Person	3 Person	4 Person	5 Person	6 Person	7 Person	8 Person
$43,800	$50,050	$56,300	$62,550	$67,600	$72,600	$77,600	$82,600

Continued on reverse

How do I enroll in the Emergency Rental Assistance Program?

Each county has a different application process, and benefits may vary by county. Catholic Charities is processing paper applications for Lehigh County.

Download a paper application at the Department of Human Services website at https://www.dhs.pa.gov/coronavirus/Pages/Emergency-Rental-Assistance-Program.aspx

If you have questions, email ERAP@allentowndiocese.org.

When you apply, please reference your UGI account number {Contract Account} with a service address of {Service Address} in {Service City}.

UGI Customer Service Team

Energy to do more®

Emergency Rental Assistance Program Solicitations March 2021 – General Email

Audience: Renters

Energy to do more®

Dear Kelly Diamonds,

We know the last few months have been both stressful and challenging. We're committed to making things easier for our customers. You may qualify for the Emergency Rental Assistance Program. (If you're not a renter, please visit www.ugi.com/reliefnow to learn about other assistance that may be available to you.)

The United States Treasury recently approved this program to assist renters that are struggling financially due to the COVID-19 pandemic. **Benefits include assistance with utility accounts (electric, natural gas), water bills and rent.** Utility and rent incurred from March 2020 through present will be considered.

How do I qualify for the Emergency Rental Assistance Program?

- One or more individuals in your household has qualified for unemployment benefits, or experienced a reduction in household income, incurred significant costs, or experienced other financial hardship due, directly or indirectly, to the pandemic
- One or more individuals demonstrate a risk of experiencing homelessness or housing instability, which may include a past due utility or rent notice or eviction notice, unsafe or unhealthy living conditions, or any other evidence of such risk
- The household income does not exceed 80% of the median income for your county; income is based on total income for calendar year 2020, or confirmation of monthly income at the time of application

Learn More **about qualifications for benefits available in your county**

How do I enroll in the Emergency Rental Assistance Program?

Each county has a different application process, and benefits may vary by county. Click here to view county contacts or download the paper application to submit to the address specific to your county.

When you apply, please reference your UGI account number **411003378022** with a service address of 514 Front St Rear in Scranton.

UGI Customer Service Team

COVID-19 RESPONSE PLAN | GAS SAFETY | ELECTRIC SAFETY

Energy to do more®

Emergency Rental Assistance Program Solicitations March 2021 – Direct Mail, General Messaging*

Audience: Renters

We know the last few months have been both stressful and challenging. We're committed to making things easier for our customers. You may qualify for the Emergency Rental Assistance Program. (If you're not a renter, please visit www.ugi.com/reliefnow to learn about other assistance that may be available to you.)

The United States Treasury recently approved this program to assist renters that are struggling financially due to the COVID-19 pandemic. Benefits include assistance with utility accounts (electric, natural gas), water bills and rent. Utility and rent incurred from March 2020 through present will be considered.

How do I qualify for the Emergency Rental Assistance Program (ERAP)?

- One or more individuals in your household has qualified for unemployment benefits, or experienced a reduction in household income, incurred significant costs, or experienced other financial hardship due, directly or indirectly, to the pandemic
- One or more individuals demonstrate a risk of experiencing homelessness or housing instability, which may include a past due utility or rent notice or eviction notice, unsafe or unhealthy living conditions, or any other evidence of such risk
- The household income does not exceed 80% of the average median income (AMI) for your county; income is based on total income for calendar year 2020, or confirmation of monthly income at the time of application.

Refer to the enclosed "ERAP Annual Income Limits" document to view income guidelines specific to your county.

How do I enroll in the Emergency Rental Assistance Program?

Each county has a different application process, and benefits may vary by county. Many counties are accepting online applications using the COMPASS website.

COMPASS Website: https://www.compass.state.pa.us/Compass.Web/RAP/Application

Refer to the enclosed "ERAP County Contacts" document to find the contact information specific to the county in which you reside.

When you apply, please reference your UGI account number {Contract Account} with a service address of {Service Address} in {Service City}.

UGI Customer Service Team

COUNTY CONTACTS FOR THE EMERGENCY RENTAL ASSISTANCE PROGRAM

DEPARTMENT OF HUMAN SERVICES WEBSITE: https://www.dhs.pa.gov/coronavirus/Pages/Emergency-Rental-Assistance-Program.aspx

COUNTY	AGENCY	STREET ADDRESS	CITY	PHONE	EMAIL	WEBSITE	COMPASS ONLINE APPLICATION
ADAMS	SOUTH CENTRAL COMMUNITY ACTION PROGRAMS	153 N STRATTON ST.	GETTYSBURG, PA 17325		[illegible]		Y
BEDFORD	CENTER FOR COMMUNITY ACTION	195 DRIVE IN LANE	EVERETT, PA 15537		[illegible]		Y
BLAIR	BLAIR COUNTY COMMUNITY ACTION	2100 6TH AVE	ALTOONA, PA 16602		[illegible]		Y
BRADFORD	TRIHAB	PO BOX 127	TOWANDA, PA 18848		[illegible]		Y
BUCKS	BUCKS COUNTY			1-888-50-BUCKS		www.buckscounty.org/rentalhelp	N
CARBON	CATHOLIC CHARITIES	900 SOUTH WOODWARD STREET	ALLENTOWN, PA 18103	610-435-1541		www.catholiccharitiesad.org	N
CENTRE	CENTRE COUNTY OFFICE OF ADULT SERVICES	2580 E. COLLEGE AVE. STE. 1200	STATE COLLEGE, PA 16801		[illegible]		Y
CHESTER	CHESTER COUNTY			211 and select prompt 2			N
CLARION	CLARION COUNTY HOUSING AUTHORITY	8 WEST MAIN STREET	CLARION, PA 16214	814-226-8910	[illegible]		Y
CLEARFIELD	CENTRAL PA COMMUNITY ACTION, INC.	PO BOX 792 207 EAST CHERRY STREET	CLEARFIELD, PA 16830				
CLINTON	CLINTON COUNTY HOUSING COALITION	302 E MAIN ST	LOCK HAVEN, PA 17745				
FOREST	WARREN-FOREST COUNTIES ECONOMIC OPPORTUNITY COUNCIL INC.	P.O. BOX 547	WARREN, PA 16365				
FRANKLIN	SOUTH CENTRAL COMMUNITY ACTION PROGRAMS	1015 MAIN ST	CHAMBERSBURG, PA 17201				
HUNTINGDON	CENTER FOR COMMUNITY ACTION	510 WASHINGTON STREET	HUNTINGDON, PA 16652				
MCKEAN	MCKEAN COUNTY REDEVELOPMENT & HOUSING AUTHORITY	11 CAMPUS DRIVE	BRADFORD, PA 16701				
MIFFLIN	MIFFLIN JUNIATA HUMAN SERVICES	20 N. WAYNE STREET	LEWISTOWN, PA 17044				
[illegible]	CENTRAL SUSQUEHANNA OPPORTUNITIES, INC.	2 EAST ARCH ST.	SHAMOKIN, PA 17872				
MONTGOMERY	MANNA ON MAIN STREET	606 MAIN ST	LANSDALE, PA 19446				
MONTOUR	MONTOUR COUNTY HUMAN SERVICES	405 EAST FRONT STREET	DANVILLE, PA 17821				
PIKE	PIKE COUNTY HUMAN SERVICES	506 BROAD ST	MILFORD, PA 18337				
POTTER	POTTER COUNTY HUMAN SERVICES	62 NORTH STREET	ROULETTE, PA 16746				
SCHUYLKILL	SCHUYLKILL COMMUNITY ACTION	206 N 2ND ST.	POTTSVILLE, PA 17901				
SNYDER	UNION-SNYDER COMMUNITY ACTION AGENCY	713 BRIDGE STREET SUITE 10	SELINSGROVE, PA 17870				
SUSQUEHANNA	SUSQUEHANNA COUNTY HOUSING/REDEVELOPMENT AUTHORITY	31 PUBLIC AVE PO BOX 366	MONTROSE, PA 18801				
UNION	UNION-SNYDER COMMUNITY ACTION AGENCY	713 BRIDGE STREET SUITE 10	SELINSGROVE, PA 17870				
VENANGO	VENANGO COUNTY CSI	1 DALE AVENUE	FRANKLIN, PA 16323				
WAYNE	WAYNE COUNTY OFFICE OF HUMAN SVC	314 10TH STREET	HONESDALE, PA 18431				
WYOMING	CEO HOUSING DEPARTMENT	P.O. BOX 1126	WILKES-BARRE, PA 18703-1126				
YORK	COMMUNITY PROGRESS COUNCIL	226 EAST COLLEGE AVENUE	YORK, PA 17403				

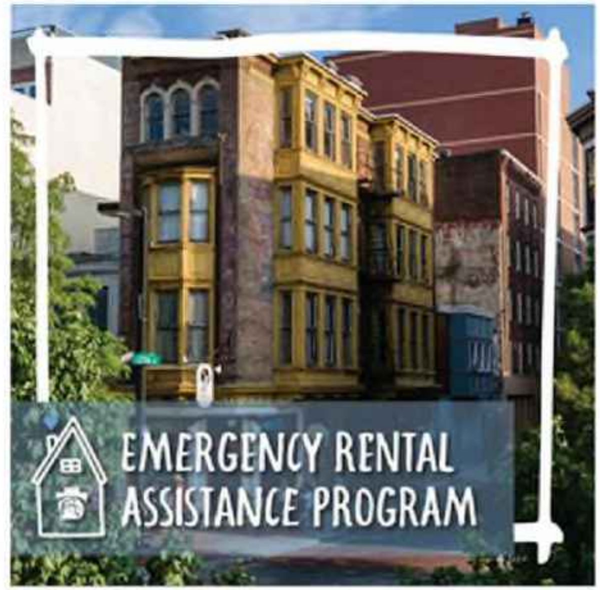
ERAP Annual Income Limits
80% of the Area Median Income by County

County	80% AMI 1 Person	80% AMI 2 Person	80% AMI 3 Person	80% AMI 4 Person	80% AMI 5 Person	80% AMI 6 Person	80% AMI 7 Person	80% AMI 8 Person
Adams	$47,950	$54,800	$61,650	$68,500	$74,000	$79,500	$84,950	$90,450
Allegheny	$46,500	$53,150	$59,800	$66,400	$71,750	$77,050	$82,350	$87,650
Armstrong	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Beaver	$46,500	$53,150	$59,800	$66,400	$71,750	$77,050	$82,350	$87,650
Bedford	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Berks	$44,050	$50,350	$56,650	$62,900	$67,950	$73,000	$78,000	$83,050
Blair	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Bradford	$37,600	$43,000	$48,350	$53,700	$58,000	$62,300	$66,600	$70,900
Bucks	$54,150	$61,850	$69,600	$77,300	$83,500	$89,700	$95,900	$102,050
Butler	$46,500	$53,150	$59,800	$66,400	$71,750	$77,050	$82,350	$87,650
Cambria	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Cameron	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Carbon	$43,800	$50,050	$56,300	$62,550	$67,600	$72,600	$77,600	$82,600
Centre	$49,700	$56,800	$63,900	$70,950	$76,650	$82,350	$88,000	$93,700
Chester	$54,150	$61,850	$69,600	$77,300	$83,500	$89,700	$95,900	$102,050
Clarion	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Clearfield	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Clinton	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Columbia	$36,900	$42,150	$47,400	$52,650	$56,900	$61,100	$65,300	$69,500
Crawford	$37,000	$42,250	$47,550	$52,800	$57,050	$61,250	$65,500	$69,700
Cumberland	$47,600	$54,400	$61,200	$68,000	$73,450	$78,900	$84,350	$89,800
Dauphin	$47,600	$54,400	$61,200	$68,000	$73,450	$78,900	$84,350	$89,800
Delaware	$54,150	$61,850	$69,600	$77,300	$83,500	$89,700	$95,900	$102,050
Elk	$37,450	$42,800	$48,150	$53,500	$57,800	$62,100	$66,350	$70,650
Erie	$40,050	$45,800	$51,500	$57,200	$61,800	$66,400	$70,950	$75,550
Fayette	$46,500	$53,150	$59,800	$66,400	$71,750	$77,050	$82,350	$87,650
Forest	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Franklin	$43,900	$50,150	$56,400	$62,650	$67,700	$72,700	$77,700	$82,700
Fulton	$36,600	$41,800	$47,050	$52,250	$56,450	$60,650	$64,800	$69,000
Greene	$37,450	$42,800	$48,150	$53,500	$57,800	$62,100	$66,350	$70,650
Huntingdon	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Indiana	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Jefferson	$36,350	$41,550	$46,750	$51,900	$56,100	$60,250	$64,400	$68,550
Juniata	$36,600	$41,800	$47,050	$52,250	$56,450	$60,650	$64,800	$69,000
Lackawana	$40,150	$45,900	$51,650	$57,350	$61,950	$66,550	$71,150	$75,750

*Annual Income Limits by County and County Contacts Source: DHS Website

ERAP Email Message to Landlords

- Sent 8/4/2021
- Email audience = 20 landlords



Dear Landlord,

We wanted to remind you that CARES Act funding for the Emergency Rental Assistance Program is still available and can benefit both you and your tenants.

The Emergency Rental Assistance Program (ERAP) has been open for a few months, yet many eligible customers have not yet applied. **Benefits include assistance with utility accounts (electric, natural gas), water bills and rent.** Utility and rent incurred from March 2020 through present will be considered.

LEARN MORE ABOUT ERAP

If you or your tenant apply for ERAP to help with UGI bills, please be sure their UGI account number and service address is referenced on the application. If you or your tenant applies for benefits to pay UGI bills, please be sure to contact us at 800-276-2722 so we can note your account accordingly.

UGI Customer Service Team

ERAP Email Message to Tenants*

- Sent 8/5/2021
- Audience size 47,353

*Based on active residential customers with Unit # populated in SAP

Rent and Utility Help is Available

Have you lost a job or income because of COVID-19? CARES Act funds are available through the Emergency Rental Assistance Program* (ERAP).

ERAP help is available if:

- You are experiencing a financial hardship due to COVID-19;
- You are experiencing housing instability or may lose your home;

AND

- You meet income thresholds specific to your county

**ERAP is a national program funded as a result of the CARES Act. UGI does not administer this program. Complete program information is available through the PA Department of Human Services website.*

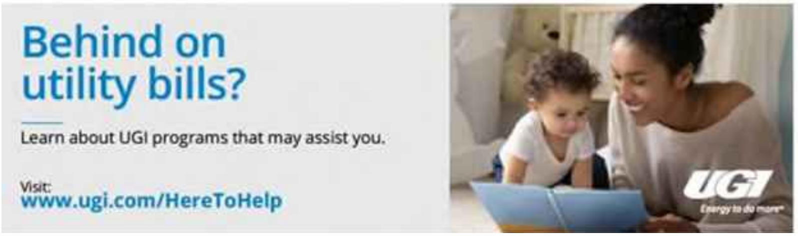
Don't wait - apply today!

If you apply for benefits to pay your UGI bill, please reference UGI account number **411006705817** with a service address of 448 N 4th St Unit 2 in Sunbury and contact UGI at 800-276-2722 to alert us that you are applying so we can note your account accordingly.

UGI Customer Service Team

ERAP Billboard Placements & Dates (Fall 2021)

- Placed 9/21 – Allentown Poster (Route 22 & MacArthur Road) – "Here to Help"
- Placed 9/21 – Lancaster Poster (Route 30) – "ERAP"
- Placed 9/21 – Lancaster Poster (Manheim Pike) – "Here to Help"
- Placed 9/21 – Luzerne Digital (Cross Valley Expressway) – "ERAP"
- Placed 9/21 – Reading Digital (Warren Street bypass, w/o of Allegeny) – "Here to Help"
- Placed 9/22 – Reading Poster (Lancaster Ave / New Holland Road) – "Here to Help"
- Placed 9/29 – Harrisburg Poster (Cameron St) – "Here to Help"
- Placed 9/29 – Harrisburg Poster (S 13th St) – "ERAP"



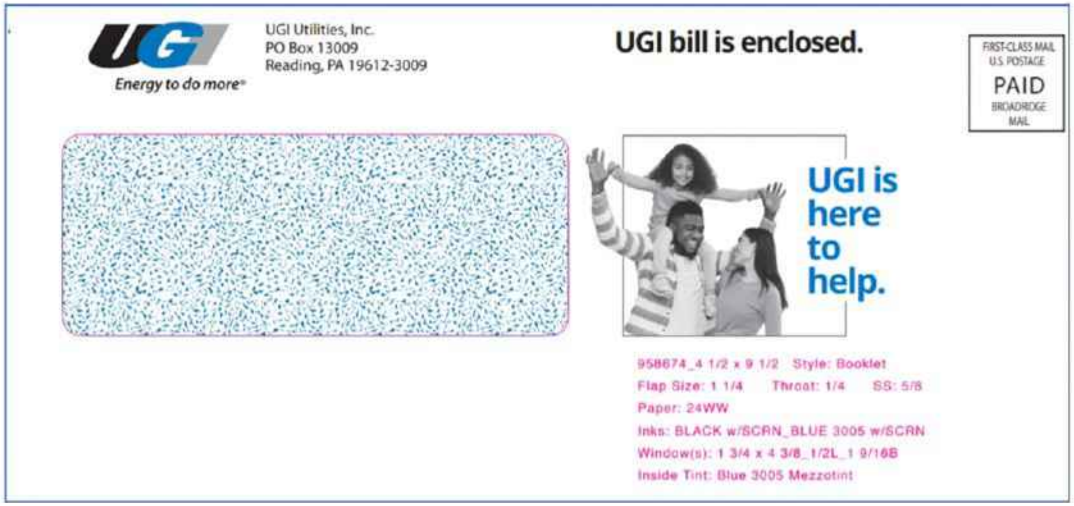
Customer Assistance Programs Communications & Audiences

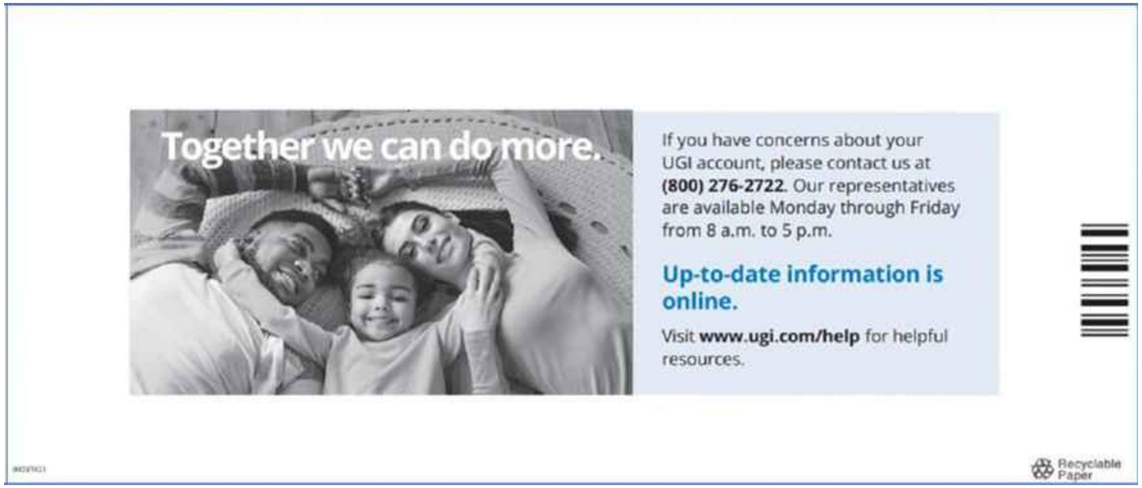
Energy to do more®

Bill Envelope – November 2022 through March 2022

Energy to do more®

Bill Envelopes – June 2020 – October 2021





LIHEAP Bill Insert (March 2020 – March 2021)

- Included with all customer's bills
- Inserted / included with bills sent:
  - March 2020
  - November 2020
  - December 2020
  - January 2021 through March 2021

00233288

Need a helping hand?

You may be eligible for LIHEAP, an energy assistance program designed to help pay your heating bills.

Free heating assistance is available.

Turn to the back of this insert for additional information.

Energy to do more®

LIHEAP assistance available.

Pennsylvania's Low-Income Home Energy Assistance Program (LIHEAP) helps eligible energy consumers pay their heating bills through energy assistance grants. If eligible, a grant is sent to UGI on your behalf. The minimum amount of a LIHEAP cash grant is $200. The maximum is $1,000.

Contact UGI at 1 800 UGI-WARM (1 800-844-9276) for an application if you meet the income guidelines at right:

To fill out an application online, log on to www.ugi.com/LIHEAP

	Monthly income	Annual income
1 person	$1,561	$18,735
2 people	$2,114	$25,365
3 people	$2,666	$31,995
4 people	$3,219	$38,625
5 people	$3,771	$45,255
6 people	$4,324	$51,885
7 people	$4,876	$58,515
8 people	$5,429	$65,145
each additional person		$6,630

Para mas información o si tiene preguntas sobre ayuda con su cuenta de UGI llame al 1 800 UGI-WARM.

Energy to do more®

LIHEAP Bill Insert - November 2021 - Present

- Included with all customer's bills
- Inserted / included with bills sent November 2021 through January 2022

00265338

Need a helping hand?

You may be eligible for LIHEAP, an energy assistance program designed to help pay your heating bills.

Free heating assistance is available.

Turn to the back of this insert for additional information.

Energy to do more®

LIHEAP assistance available.

Pennsylvania's Low-Income Home Energy Assistance Program (LIHEAP) helps eligible energy consumers pay their heating bills through energy assistance grants. If eligible, a grant is sent to UGI on your behalf. The minimum amount of a LIHEAP cash grant is $500. The maximum is $1,500.

Contact UGI at 1 800 UGI-WARM (1 800-844-9276) for an application if you meet the income guidelines at right:

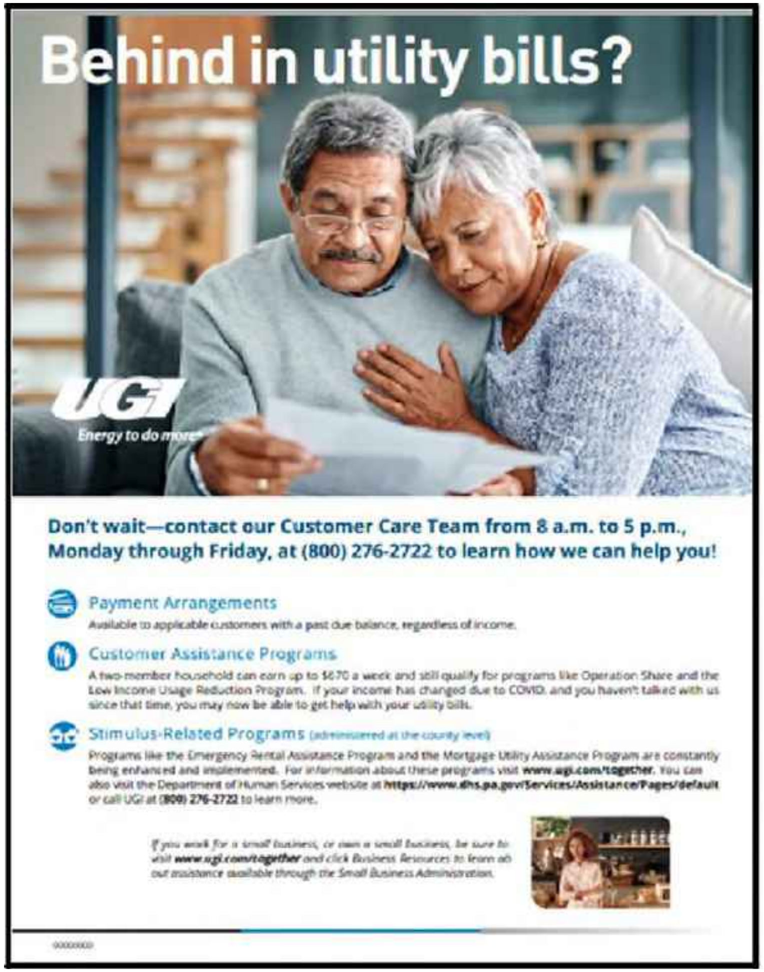
To fill out an application online, log on to www.ugi.com/LIHEAP

	Monthly income	Annual income
1 person	$1,610	$19,320
2 people	$2,178	$26,130
3 people	$2,745	$32,940
4 people	$3,313	$39,750
5 people	$3,880	$46,560
6 people	$4,448	$53,370
7 people	$5,015	$60,180
8 people	$5,583	$66,990
each additional person	$568	$6,810

Para mas información o si tiene preguntas sobre ayuda con su cuenta de UGI llame al 1 800 UGI-WARM.

Energy to do more®

Bill Assistance Bill Insert (Two-Sided)
July 2021 & September 2021 (All Customers)



Behind in utility bills?

UGI Energy to do more®

Don't wait—contact our Customer Care Team from 8 a.m. to 5 p.m., Monday through Friday, at (800) 276-2722 to learn how we can help you!

Payment Arrangements
Available to applicable customers with a past due balance, regardless of income.

Customer Assistance Programs
A two-member household can earn up to $670 a week and still qualify for programs like Operation Share and the Low Income Usage Reduction Program. If your income has changed due to COVID, and you haven't talked with us since that time, you may now be able to get help with your utility bills.

Stimulus-Related Programs (administered at the county level)
Programs like the Emergency Rental Assistance Program and the Mortgage Utility Assistance Program are constantly being enhanced and implemented. For information about these programs visit **www.ugi.com/together**. You can also visit the Department of Human Services website at **https://www.dhs.pa.gov/Services/Assistance/Pages/default** or call UGI at **(800) 276-2722** to learn more.

*If you work for a small business, or own a small business, be sure to visit **www.ugi.com/together** and click Business Resources to learn about assistance available through the Small Business Administration.*

¿Está atrasado con las facturas de servicios públicos?

UGI Energy to do more®

¡No espere más! Comuníquese con nuestro Equipo de Atención al Cliente de 8 a. m. a 5 p. m., de lunes a viernes, al (800) 276-2722 para saber cómo podemos ayudarlo.

Acuerdos de Pago
Disponibles para clientes que cumplen los requisitos con un saldo vencido, independientemente de sus ingresos.

Programas de Asistencia al Cliente
Un hogar de dos miembros puede ganar hasta $670 por semana y aun así calificar para programas como Operation Share y el Programa de reducción de consumo para hogares de bajos recursos. Si sus ingresos han cambiado debido a la COVID-19 y no ha hablado con nosotros desde ese momento, es posible que ahora pueda obtener ayuda con sus facturas de servicios públicos.

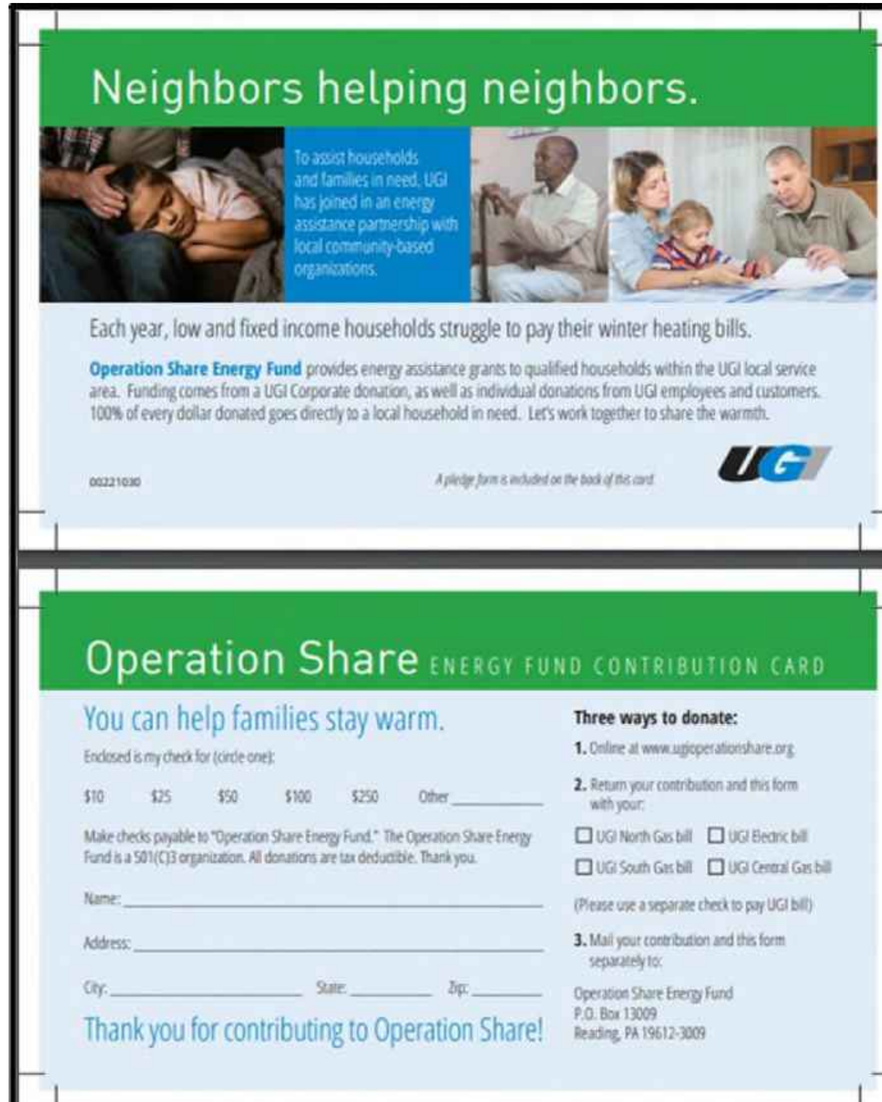
Programas Relacionados con los Estímulos Económicos (administrados a nivel del condado)
Programas como el Programa de asistencia para alquileres de emergencia y el Programa de asistencia para servicios públicos e hipotecas se están mejorando e implementando constantemente. Para obtener información sobre estos programas, visite **www.ugi.com/together**. También puede visitar el sitio web del Departamento de Servicios Humanos en **https://www.dhs.pa.gov/services/assistance** o llamar a UGI al **(800) 276-2722** para obtener más información.

*Si trabaja para un pequeño negocio o es propietario de un pequeño negocio, asegúrese de visitar **www.ugi.com/together** y haga clic en "Business Resources" (Recursos Empresariales) para obtener más información sobre la asistencia disponible a través de la Agencia Federal de Pequeños Negocios.*

Energy to do more®

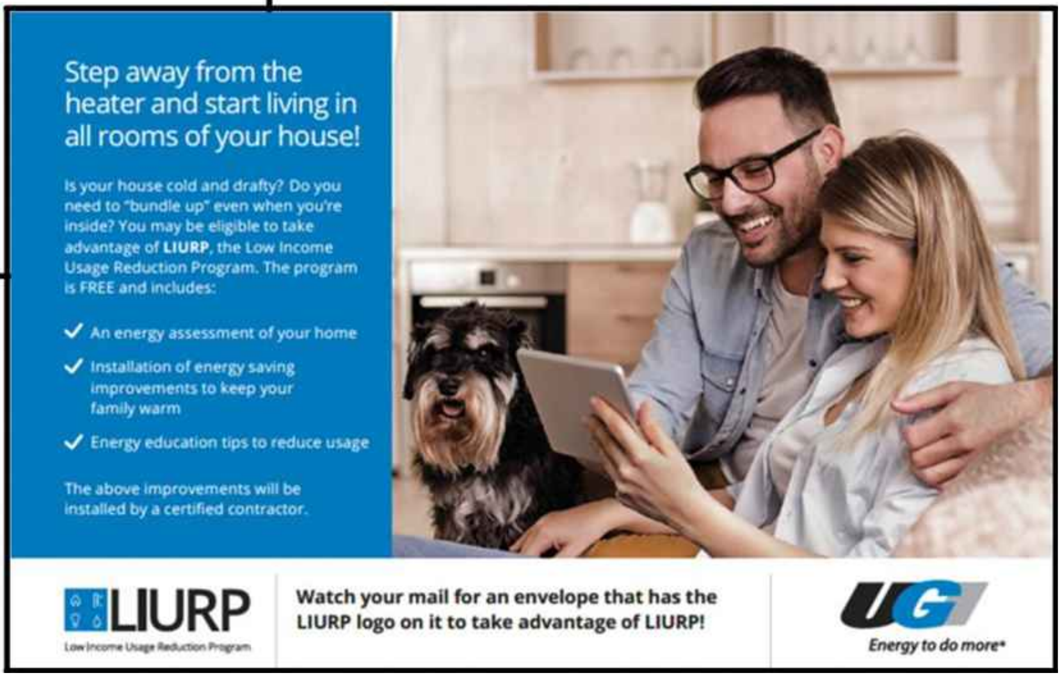
Operation Share Bill Insert

- Included with all customer's bills
- Inserted / included with bills sent:
  - March 2020 through July 2020
  - September 2020 through November 2020
  - January 2021 through July 2021
  - September 2021 through December 2021



Energy to do more®

LIURP SEDACOG Pilot Program – Postcard



Ebill “Ad”

Destination is UGI LIHEAP Page

Footer of Bill Available and Bill Due Email Notifications Sent to eBill Customers in January 2022 from SEW / Online Portal

Assistance Grants Now Available

Pennsylvania’s Low-Income Home Energy Assistance Program (LIHEAP) offers FREE energy assistance grants to income-qualified customers. Applying is easy, and you do not have to have an unpaid bill to receive these grants.

LEARN MORE

Energy to do more®

LIHEAP UFT – February/March 2021

Email Audience: 5,119 Direct Mail: 1,867

Energy to do more®

Dear %%=Propercase(Name)=%%,

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2020-21 heating season on account **%%[var @Account set @Account = [Contract Account Number]]%% %%=FormatNumber(@Account)=%%** with a service address of %%[var @Address set @Address = [Street Address]]%% %%=Propercase(@Address)=%% in %%=Propercase(City)=%% and therefore you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $800 for customers who are in jeopardy of losing their heat.

Based on receipt of your 2020-21 LIHEAP grant, UGI Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance.

We need to hear from you so you do not miss out on the additional funding!

- **Call us at** 800-UGI-WARM (800-844-9276) and select Option 1 then Option 1 Monday through Friday, from 8 am to 5 pm; OR
- **Email us at** CARES@ugi.com – be sure to provide the name on your UGI account, your UGI account number, and that you agree that UGI should pursue additional LIHEAP funding for you

If you DO NOT want UGI to submit your account to receive the additional 2020-21 LIHEAP CRISIS funds you do not need to take any action at this time.

Best Regards,

UGI Customer Outreach Team

Energy to do more®

(Date)

Bar Code
(Business Partner)
(Mailing Address)
(Mailing Address)

Dear (Business Partner),

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2020-21 heating season on UGI account (Account #) for (service address) in (Service City) and therefore you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $800 for customers who are in jeopardy of losing their heat.

Based on receipt of your 2020-21 LIHEAP grant, UGI Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance.

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If you DO NOT want UGI to submit your account to receive the additional 2020-21 LIHEAP CRISIS funds you do not need to take any action at this time.

Best Regards,

UGI Customer Outreach Department

LIHEAP – Email March 2021

Audience: 11,314 CAP No LIHEAP

Based on information in our system, your household income may qualify for LIHEAP but we've noticed you have not yet had any LIHEAP payments applied to your account since the start of the heating season on October 1, 2020. If you've completed the LIHEAP application already, great! You're one step closer to receiving $200 (or more*) towards your winter heating bills.

If you haven't completed the form or applied online, we would like to assist you to make this process as simple as possible. **The program close has been extended until April 30, 2021 so act now!**

Click the button below to apply through COMPASS, the state website to help you receive LIHEAP funding.

APPLY FOR LIHEAP THROUGH COMPASS

About LIHEAP

The Low Income Home Energy Assistance Program (LIHEAP) is a federally funded program that helps pay heating bills through energy assistance grants*. The grants do not need to be paid back. Grants are applied directly to your utility account. You can apply online through the Pennsylvania state's COMPASS website.

View this short video to learn more about all of the benefits available through COMPASS.

Income Guidelines

Household Members	Annual Income	Monthly Income	Weekly Income
1	$19,140	$1,595	$368
2	$25,860	$2,155	$497
3	$32,580	$2,715	$627
4	$39,300	$3,275	$756

For additional person, add $6,720 per person annual income, $560/person monthly income or $129/weekly income.

*Minimim LIHEAP CASH grant is $200, with $1,000 maximum.

More Savings Could Be Available Through LIURP

Are your energy bills high even though your thermostat is set at a low temperature? The UGI Low Income Usage Reduction Program (LIURP) offers free weatherization measures to qualified low-income residential heating customers in order to limit heat loss and provide long-term energy savings. These energy savings measures may include window and baseboard caulking, door and window weather-stripping, attic and sidewall insulation, duct and pipe insulation, ventilation, water conservation devices, furnace inspections and energy education. Learn More

Have Questions? We're here to help!

If you have questions about any of the Customer Assistance Programs available to UGI customers please contact us at 800-UGI-WARM (800-844-9276). Our Customer Service Representatives are available Monday through Friday from 8:00 am to 5:00 pm.

Thank you for allowing us the opportunity to serve you!

UGI Customer Service Team

Energy to do more®

LIHEAP – Reminder April 2021

Audience: 8,152 Non-Open, Non-Respond

Energy to do more®

Based on information in our system, your household income may qualify for LIHEAP but we've noticed you have not yet had any LIHEAP payments applied to your account since the start of the heating season on October 1, 2020. If you've completed the LIHEAP application already, great! You're one step closer to receiving $200 (or more*) towards your winter heating bills.

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Thank you for allowing us the opportunity to serve you!

UGI Customer Service Team

Active Accounts - LIHEAP Additional Funds – Opt In August 2021

Email Audience: 448 Direct Mail Audience: 261

Energy to do more

Dear Genesis Garcia Alamo,

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2020-21 heating season on UGI account **421002851838** with a service address of 31 S 5th Ave in Lebanon and therefore you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $1,200 for customers who are in jeopardy of losing their heat.

Based on receipt of your 2020-21 LIHEAP grant, UGI Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance.

We need to hear from you before September 13, 2021 so you do not miss out on the additional funding!

- **Call us at** 800-UGI-WARM (800-844-9276) and select Option 1 then Option 1 Monday through Friday, from 8 am to 5 pm; OR
- **Email** CARES@ugi.com - copy and paste the information in green into the body of the email you send us: "Yes, I want UGI to pursue additional LIHEAP funds for my UGI account # **421002851838**. The name on my UGI account is Genesis Garcia Alamo"; OR
- **Text LIHEAP2021 to 84484**

If you DO NOT want UGI to submit your account to receive the additional 2020-21 LIHEAP CRISIS funds you do not need to take any action at this time.

Best Regards,

UGI Customer Outreach Team

Energy to do more

(Date)

Bar Code
{Business Partner}
{Mailing Address}
{Mailing Address}

Dear {Business Partner},

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2020-21 heating season on UGI account {Account #} for {service address} and therefore you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $1,200 for customers who are in jeopardy of losing their heat.

Based on receipt of your 2020-21 LIHEAP grant, UGI Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance.

We need to hear from you by September 13, 2021 so you do not miss out on the additional funding!

- **Call us at 800.UGI.WARM** (800-844-9276) Monday through Friday, from 8 am to 5 pm
- **Email us at CARES@ugi.com** – be sure to provide the name on your UGI account, your UGI account number, and that you agree that UGI should pursue additional LIHEAP funding for you
- **Text LIHEAP2021 to 84484** – you will then be prompted to provide your UGI account number and name to confirm you are opting in

If you DO NOT want UGI to submit your account to receive the additional 2020-21 LIHEAP CRISIS funds you do not need to take any action at this time.

Best Regards,

UGI Customer Outreach Department

Energy to do more®

Inactive Accounts – LIHEAP Additional Funds – Opt In August 2021

Email Audience: 323 Direct Mail Audience: 76

Energy to do more®

Dear Dallas Ware,

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2020-21 heating season on UGI account **411003247391** with a service address of 582 W Louther St in Carlisle and therefore you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $1,200 for customers who are in jeopardy of losing their heat or have lost their heat due to service termination.

Based on receipt of your 2020-21 LIHEAP grant, UGI Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance. Funds will be applied in November 2021.

We need to hear from you before September 13, 2021* so you do not miss out on the additional funding!

- Call us at 800-UGI-WARM (800-844-9276) and select Option 1 then Option 1 Monday through Friday, from 8 am to 5 pm; OR
- Email CARES@ugi.com - copy and paste the information in green into the body of the email you send us: "Yes, I want UGI to pursue additional LIHEAP funds for my UGI account # **411003247391**. The name on my UGI account is Dallas Ware"; OR
- **Text LIHEAP2021 to 84484**

*Replying to us through any of the methods listed above means you are opting in to receive the funds.

If you DO NOT want UGI to submit your account to receive the additional 2020-21 LIHEAP CRISIS funds you do not need to take any action at this time.

Energy to do more®

August 17, 2021

BONNIE J RHOADS
4642 ROUTE 338
KNOX PA 16232-3654

Dear BONNIE J RHOADS,

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2020-21 heating season on UGI account 411007562605 with a service address of 4642 ROUTE 338 in KNOX and therefore you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $1,200 for customers who are in jeopardy of losing their heat or have lost their heat due to service termination.

Based on receipt of your 2020-21 LIHEAP grant, UGI Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance. Funds will be applied in November 2021.

We need to hear from you before September 13, 2021* so you do not miss out on the additional funding!

- Call us at 800-UGI-WARM (800-844-9276) and select Option 1 then Option 1 Monday through Friday, from 8 am to 5 pm; OR
- Email CARES@ugi.com – include the information in green into the body of the email you send us: "Yes, I want UGI to pursue additional LIHEAP funds for my UGI account # 411007562605. The name on my UGI account is BONNIE J RHOADS"; OR
- **Text LIHEAP2021 to 84484**

*Replying to us through any of the methods listed above means you are opting in to receive the funds.

If you DO NOT want UGI to submit your account to receive the additional 2020-21 LIHEAP CRISIS funds you do not need to take any action at this time.

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LIHEAP UFT Reminder Email Sent 9/9/21 to Non-responders

Current Customers Audience: 372 Inactive Customer Audience: 284

Energy to do more®

Dear Lomuna Bongongo,

REMINDER: RESPONSE NEEDED BY SEPTEMBER 14, 2021 TO RECEIVE UTILITY BILL FUNDS

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2020-21 heating season on UGI account **411000420082** with a service address of 128 Bradford St in Millersville and therefore you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $1,200 for customers who are in jeopardy of losing their heat.

Based on receipt of your 2020-21 LIHEAP grant, UGI Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance. Funds will be applied in November 2021.

We need to hear from you before September 14, 2021* so you do not miss out on the additional funding!

- **Call us at** 800-UGI-WARM (800-844-9276) and select Option 1 then Option 1 Monday through Friday, from 8 am to 5 pm; OR
- **Email** CARES@ugi.com - copy and paste the information in green into the body of the email you send us: "Yes, I want UGI to pursue additional LIHEAP funds for my UGI account # 411000420082. The name on my UGI account is Lomuna Bongongo"; OR
- **Text LIHEAP2021 to 84484**

*Replying to us through any of the methods listed above means you are opting in to receive the funds.

If you DO NOT want UGI to submit your account to receive the additional 2020-21 LIHEAP CRISIS funds you do not need to take any action at this time.

Best Regards,

UGI Customer Outreach Team

Energy to do more®

Dear Shakeya Rainey,

REMINDER: RESPONSE NEEDED BY SEPTEMBER 14, 2021 TO RECEIVE UTILITY BILL FUNDS

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2020-21 heating season on UGI account **411000565407** with a service address of 1526 Green St Apt 3 in Harrisburg and therefore you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $1,200 for customers who are in jeopardy of losing their heat or have lost their heat due to service termination.

Based on receipt of your 2020-21 LIHEAP grant, UGI Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance. Funds will be applied in November 2021.

We need to hear from you before September 14, 2021* so you do not miss out on the additional funding!

- **Call us at** 800-UGI-WARM (800-844-9276) and select Option 1 then Option 1 Monday through Friday, from 8 am to 5 pm; OR
- **Email** CARES@ugi.com - copy and paste the information in green into the body of the email you send us: "Yes, I want UGI to pursue additional LIHEAP funds for my UGI account # 411000565407. The name on my UGI account is Shakeya Rainey"; OR
- **Text LIHEAP2021 to 84484**

*Replying to us through any of the methods listed above means you are opting in to receive the funds.

If you DO NOT want UGI to submit your account to receive the additional 2020-21 LIHEAP CRISIS funds you do not need to take any action at this time.

Best Regards,

UGI Customer Outreach Team

Energy to do more®

LIHEAP Opt-In – February 2022

Email Audience: 167 Direct Mail Audience: 146

Energy to do more®

Dear %%=Propercase(Name)=%%,

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year, LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2021-22 heating season on account %%[var @Account set @Account = [Contract Account Number]]%%%%=FormatNumber(@Account)=%% with a service address of %%[var @Address set @Address = [Street Address]]%%%%=Propercase(@Address)=%% in %%=Propercase(City)=%%, and therefore, you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $1,200 for customers who are in jeopardy of losing their heat.

Based on receipt of your 2021-22 LIHEAP grant, Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance.

We need to hear from you before February 24, 2022 so you do not miss out on the additional funding!

- **Call us at 800-UGI-WARM** (800-844-9276, Option 1)
  - Monday through Friday, from 8 am to 5 pm
- Enroll on our website

If you DO NOT want UGI to submit your account to receive the additional 2021-22 LIHEAP CRISIS funds, you do not need to take any action at this time.

Best Regards,

UGI Customer Outreach Department

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February 11, 2022

DOUGLAS BRENNER
154 E WALNUT ST 1FR A1
LANCASTER PA 17602

Dear DOUGLAS BRENNER,

LIHEAP, a federally funded heating grant program, has additional money available that may help you pay winter heating bills. Each year LIHEAP funds go unspent because eligible households do not apply. Our records indicate that you received a LIHEAP grant during the 2021-22 heating season on UGI account 411000780477 for service at 154 E WALNUT ST in LANCASTER and therefore you may qualify for additional funds through LIHEAP CRISIS. The CRISIS fund offers a grant up to $1,200 for customers who are in jeopardy of losing their heat.

Based on receipt of your 2021-22 LIHEAP grant, UGI Utilities Inc. may be able to apply for LIHEAP CRISIS on your behalf. If eligible, UGI will submit your account to receive CRISIS funding that will be applied towards your past due balance.

We need to hear from you before February 24, 2022 so you do not miss out on the additional funding!

- **Call us at 800.UGI.WARM** (800-844-9276, option 1) Monday through Friday, from 8 am to 5 pm
- **Enroll Online at** www.ugi.com/liheap2022

If you DO NOT want UGI to submit your account to receive the additional 2021-22 LIHEAP CRISIS funds you do not need to take any action at this time.

Best Regards,

UGI Customer Outreach Department

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CAP – June 2020

Exhibit DVA-2R

Audience: 4,487

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1 UGI Drive
Denver, PA 17517

Help may be available to you. Watch your mail for details!

Coming Soon to Your Mailbox: Invitation to Enroll in Our Customer Assistance Program*

You do not have to do anything right now.

- The Customer Assistance Program provides a customized, income-based monthly bill
- If applicable, enrolling in this program will forgive past due balances

The letter you receive will have instructions on what you will need to do to take advantage of this great program.

Learn more at **www.ugi.com/aboutcap**

*Enrollment is based on household income. This invitation does not guarantee enrollment into the Customer Assistance Program.

As a reminder, our Call Center representatives are available Monday through Friday from 8 A.M. to 5 P.M. by calling **(800) 276-2722**.

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CAP Solicitation – June 2020 – Packet

June 15, 2020

«BP_NAME»
«Mailing_Address»
«Mailing_CitySTZIP»

Dear «BP_NAME»,

Our records indicate you have, in the past, received a LIHEAP grant. Based on this information, you are invited to take advantage of UGI's Customer Assistance Program ("CAP") which will assist you in managing your monthly energy bills. Enrolling in the program is free and has no impact on your credit score.

The amount you owe UGI as of June 15, 2020 for Account Number «Contract_Acct» is $«Total_Amount_Due». Enrolling in the CAP program means this amount is "frozen" and UGI will allow you to pay a lower monthly payment. For each month you make a CAP-Enrolled Monthly Payment on time, a portion of the $«Total_Amount_Due» now will be forgiven over 36 months.

Take Advantage Now!

- Complete the UGI Customer Assistance Program CAP Application, included on the following page
- Send the completed application to the Community-Based Organization for your area – this address is on the "CAP Application Agency" page
- Put the pages in this order: CAP Application Agency page on top, completed CAP application next
- Fold the packet of papers so the address is showing on the window envelope that is included in this packet

We're Here to Help

If you have questions please call us at (800) 276-2722, Monday through Friday, from 8 AM to 5 PM.

Thank you for being a customer of UGI.

Sincerely,

UGI Customer Care Team

CAP Application Agency page

- **Place the completed CAP Application underneath this page, with the address on this page facing outward**
- **With this page facing you, fold this part away from you, so you cannot read these words**
- **Fold the bottom section, with the address, so the words are showing**
- **Place the pages in the window envelope, making sure the Agency name and address is viewable through the window**
- **Attach a stamp to the envelope and mail the packet to the Agency listed**

«Agency_Name»
«Agency_Address»
«Agency_City_State_ZIP»

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CAP Solicitation – June 2020 – Packet

UGI Customer Assistance Program
CAP Application

Name on UGI Account: «BP_NAME»

Customer Account Number: «Contract_Acct»

Energy provided by UGI: «Type_of_Account»

Service Address Street: «Service_House_» «Service_Adress»

Service Address City, State Zip: «Service_City» PA «Service_ZIP»

Home Phone: ______________ Cell Phone: ________________

Email: ____________________

Household Members and Income — List the people who live with you at this address. Include all children and adults. Indicate all sources of income for each household member:

Note: Figures should represent gross monthly income.

Name	SS#	Date of Birth	M/F	Income Source(s)	Income Amount(s)
Please attach additional sheets if necessary.				**Total Gross Monthly**	$

Household Expenses — Indicate all expenses for your household:

Expense	Amount	Expense	Amount
Mortgage/Rent		Food (without food stamps)	
Water/Sewer		Electric	
Transportation		Insurance	
Medical/Prescriptions		Telephone	
Day Care/Support		Trash/Recycling	
Non-Gas/Electric Heating			

Customer Assistance Program (CAP) CONSENT AND RELEASE

I agree and consent to UGI sharing the information contained in my application and all other information relating to my customer account with those employees, representatives, agents, contractors, or subcontractors of UGI utilized to administer CAP and to evaluate my application for acceptance into CAP. Furthermore, I hereby release and hold harmless UGI, its employees, representatives, agents, contractors, and affiliates from and against any and all claims related to my application, my participation in CAP, and the administration and evaluations of UGI CAP.

Customer Assistance Program (CAP) TRUTH OF STATEMENT

The information on this application is true and complete to the best of my knowledge. The employees, representatives, agents, contractors or subcontractors of UGI have the right to verify my income and expenses if necessary. I understand and accept that providing false or incomplete statements on this application will constitute cause for rejecting my application or removing me from CAP.

Signature

Print Name Date

Permission to Contact

Do we have permission to contact you regarding your account?

☐ Home Phone ☐ Cell Phone ☐ Email

Application Instructions

- ☐ Fill out all information clearly and completely
- ☐ Provide proof of income for the most recent 30 days, 90 days, or 12-month period. Proof includes pay stubs, award letters, employer statements, etc.
- ☐ Provide a valid picture ID
- ☐ If you told us you have no income or your income is less than that of your monthly expenses you may be required to provide additional information.
- ☐ Properties that have a higher than average usage will be required to fill out additional forms.
- ☐ Signed Consent and Release and Truth of Statement

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CAP Solicitation – July/August 2021

- Audience: 2,221 customers that received LIHEAP grants but not enrolled in CAP
- Customer had to contact UGI to opt out
- Included CAP rules

July 9, 2021

SHAQUANA MCCORVEY
1135 LLOYD ST FL 2
SCRANTON PA 18508-2105

Dear SHAQUANA MCCORVEY,

Our records indicate you have, in the past, received a LIHEAP grant. Based on this information, you have been enrolled automatically in our Customer Assistance Program ("CAP") which will take effect on your next bill. You have been enrolled in the CAP Program in order to assist you in managing your monthly energy bills. Enrollment in the program is free and has no impact on your credit score.

We have included the Customer Assistance Program Rules to address any questions you may have and what is expected of you now that you are enrolled in CAP.

If you do not want to take advantage of the CAP program, or if you feel you received this offer in error, please call (800) UGI WARM and select prompt 1. **If you do not reply before August 2, 2021 your enrollment will be reflected on your next bill.**

Your Proposed Monthly Payment as a CAP-Enrolled Customer is $25.00

Please note you must pay the CAP-Enrolled Monthly Payment on time, each month, in order to remain enrolled in the CAP program. If your account remains in good standing (paid on time) each month, any past due debt you had prior to enrolling in CAP will be forgiven in equal credits over 36 months.

Thank you for being a customer of UGI.

Sincerely,

UGI Customer Care Team

CAP Recertification – October 2021 – Direct Mail

Total Audience: 3,509
(Email sent to customers with email, as “watch mail” message)

October 27, 2021

MICHAEL MOWERY
111 N ORCHARD ST
BERWICK PA 18603-3502

Customer Number 411003883245

**************** FINAL CAP RECERTIFICATION WARNING ****************

Dear CAP Customer,

An obligation of the Customer Assistance Program (CAP) is to recertify annually. Recertification is the process that requires a CAP customer to provide verification of income and household occupants to confirm they are still eligible for the program.

If you have not already submitted your updated application with proof of income and identification, you need to do the following BEFORE NOVEMBER 25, 2021:

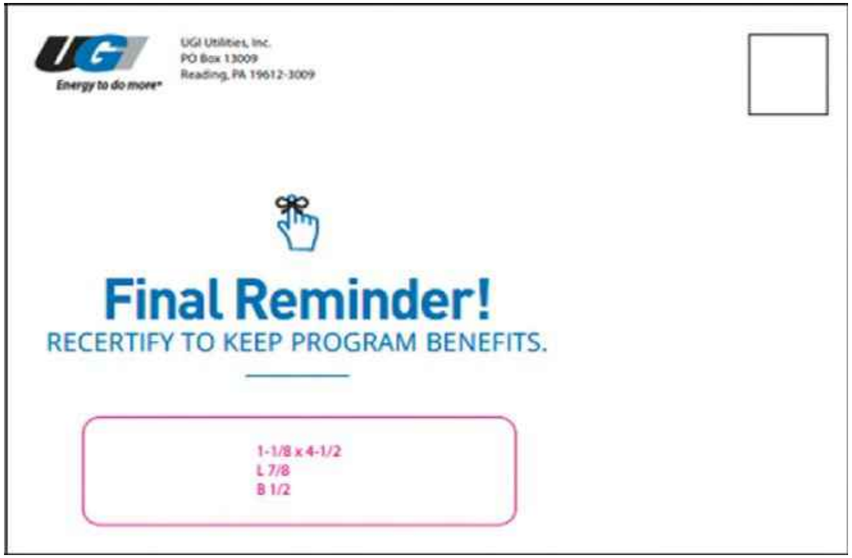
- Complete the enclosed CAP application including proof of income and proof of identification
- Submit the Application, proof of income and proof of identification to:
  AGAPE
  19 EAST 7TH STREET
  BLOOMSBURG PA 17815
  Phone: (570) 317-2210

Failure to recertify will result in your account being removed from CAP and your full balance will be due immediately.

If you have any questions, contact our Customer Care Team at (800) 276-2722; our representatives are available Monday through Friday, from 8 AM to 5 PM .

Sincerely,

Customer Outreach Department



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CAP Recertification – October 2021 - Email

Audience: 2,550 out of 3,509 customers needing to recertify

- “Watch mail” email sent to customers that needed to recertify
- Separate USPS direct mail sent with CAP application and agency information

Dear CAP Customer,

Our records show you have not completed the recertification process that will allow you to continue to participate in the Customer Assistance Program (CAP).

Please check your mailbox over the next few days. Your CAP application and instructions covering how to recertify were mailed earlier today.

What does recertification mean? To recertify you need to complete an updated CAP application, and include proof of identification and proof of income. Then, the application with proof of identity and proof of income is submitted to the agency listed below:

UGI Account Number: %%[var @Account set @Account = [Contract Account Number]]%% %%=FormatNumber(@Account)=%%

**%%=Uppercase(Name)=%%
%%[var @Address set @Address = [Street Address]]%%
%%=Uppercase(@Address)=%%
%%=Uppercase(City)=%%**

If you've recently sent the updated CAP application, proof of identity and proof of income to the agency listed above, then you can disregard this message.

If you have any questions please contact our Customer Care Team at 800-276-2722. The Customer Care Team is available Monday through Friday from 8 am to 5 pm.

UGI Customer Care Team

UGI Utilities, Inc.

COVID-19 Related Community Based Organization Communication Efforts

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March 6 – Email

Audience: CAP Community Based Organizations Related to COVID

3/6/2020

Good Afternoon,

We continue to closely monitor the evolving situation related to the 2019 Coronavirus and adapt our processes when necessary and plan accordingly. With the safety of our CBO's, staff, and customers being our highest priority we would like to encourage you and your staff to limit all CAP paperwork to mail and contact over phone. For example: if a customer forgets to sign the consent and release form please just call them and get their consent over the phone and put your signature on the page and a small note that you signed but received consent over the phone.

This is precautionary advice just based on our concerns on everyone's health and safety. As of today, there are two confirmed cases of the Coronavirus in Pennsylvania; one in Delaware County and one in Wayne County. While the risk of contracting the Coronavirus is low and there are no specific travel restrictions at this time, we do know the number of confirmed cases continue to grow in the US and it would be best to limit travel and contact whenever possible.

Thank you,

March 18 – Email

Audience: CAP Community Based Organizations Related to COVID

Good afternoon all,

Hope all is well and everyone is safe and healthy. We have been receiving a few emails from agencies regarding closures due to the pandemic. Can you please respond to this email with answers to the following questions. If you have any additional information or concerns please let us know.

1. Is/did your agency close completely?
2. Will any staff be available for customers remotely?
3. Will you continue taking applications?
4. Are customers aware of how or who to contact to get assistance?
5. What tasks (if any) have you ceased performing? (past due phone calls, recertifications, etc)
6. Is there anyone from your agency who we may contact for urgent situations?

March 21 – Email

Audience: Direct Response to an Agency

Hi [redacted]

We have told others that had concerns that they can stop working the past due calls if they wish. We know that phone calls bring in a significant amount of income for the agencies so if you would like to work them and just make them a "courtesy" call we are also fine with that. UGI is not shutting off at this time, but these phone calls could also lead a conversation into seeking LIHEAP once it opens back up in May or referring for a special circumstance OpShare grant.

Let me know if you have any other questions

Thanks,

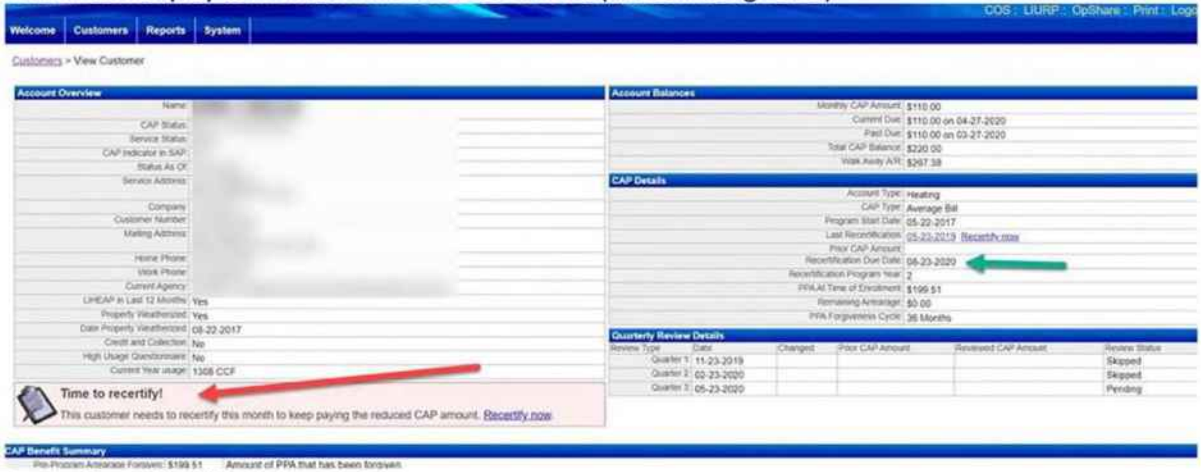
April 17 – Email

Audience: CAP Community Based Organizations Related to COVID

Hello Everyone,

Due to COVID-19 we understand the challenges it may have/be causing to get all documents and applications in for a customer's recertification on time. so we have made a change to push all recertifications due dates out 3 months. **The task on recert reminders are now triggered off of the recertification due date**. if you can continue to work the recertifications we ask you to do so, but if you are unable, we are hoping this 3 month extension will help during this time.

Green arrow: recertification due date
Red arrow: display issue that will soon be corrected (this can be ignored)



Stay safe and healthy everyone!

Thank you,

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May 6 – Email

Audience: CAP Community Based Organizations Related to COVID

Subject: Agency COVID-19 Check-in Summary

Good afternoon all,

Attached is a summary of some takeaways discussed during our conference call yesterday. Please free to let us know if you have any questions.
We hope that you and your families are staying safe and healthy during these trying times ☺ We appreciate all that you do!

Thank you,

Below are some takeaways from all agencies:

- Most agencies are waiting for governor to lift COVID-19 restrictions in order to retu office and have applied Payroll Protection Program for the time being
- Safety plan in place before re-entering customer homes
  - Making sure that customers stay in a separate room while staff is working
  - Possibility of E-signature for consent of weatherization
  - Providing surveys before visiting customers homes

For the time being UGI will allow:

- Jobs to be entered as closed, no measures to be partially compensated for in progress jobs and can be re-opened later to complete after inspection is completed
- Mid-year reviews to be extended or may not be issued this year, thus going into 3rd quarter reviews
- On temporary basis, health and safety measures can be increased $250 for both renters and homeowners
- UGI will compensate for additional mileage if needed during COVID-19. Multiple vehicles may be needed therefore mileage for each vehicle will be paid
- In addition to compensating $5 (up to 5) per contact attempt that does not result in a completed intake (withdraw, rejected) jobs, UGI will compensate $10 (up to 5) for each contact attempt you make on potential jobs in an effort to keep the customer engaged during this pandemic until you are able to visit their home. These contact attempts must be tracked on a separate spreadsheet and emailed to LIURP team titled "Administrative Contacts".

UGI Gas Exhibit DVA-3R

UGI Utilities, Inc. – Gas Division
Docket No. R-2021-3030218

INTERROGATORIES, REQUESTS FOR PRODUCTION OF
DOCUMENTS AND REQUESTS FOR ADMISSION ON CEO – SET I

2) Reference CEO Statement No. 1, page 9. Please explain how Mr. Brady derived the "rounded LIURP job cost of $7,500 per job" and provide all Documents relied upon by Mr. Brady in deriving that amount.

RESPONSE: The $7,500 is an approximate job cost derived from Appendix A of the Company's 2020-2025 USECP. The 'Projected Budget' for the three gas divisions were added and then divided by the total 'Projected Participation Levels' for those divisions.

UGI Gas Exhibit DVA-4R

UGI Utilities, Inc. – Gas Division
Docket No. R-2021-3030218

INTERROGATORIES, REQUESTS FOR PRODUCTION OF DOCUMENTS AND REQUESTS FOR ADMISSION ON CEO – SET I

6) Reference CEO Statement No. 1, pages 11-12. Please confirm that Mr. Brady's proposal is that UGI Gas increase donations to Operation Share by $1 million annually, as opposed to a one-time increase in donations to Operation Share of $1 million.

RESPONSE: A one-time increase.

UGI Gas Exhibit DVA-5R

UGI Utilities, Inc. - Gas Division

Residential Heating

Month/Year	0-51 CCF	51-100 CCI	100-151 C(	151-201 C(	201-251 C(	251-301 C(	> 300 CCF	Total Customers
10-2018	222,792	208,157	87,757	30,132	10,146	3,752	3,278	566,014
11-2018	60,182	131,884	148,805	100,693	54,332	25,349	23,816	545,061
12-2018	48,553	111,704	145,047	107,675	60,600	29,431	27,556	530,566
01-2019	38,852	91,895	139,783	125,345	85,016	48,542	56,102	585,535
02-2019	47,413	113,784	140,877	102,074	57,953	28,297	27,188	517,586
03-2019	168,244	221,298	117,848	46,566	16,810	6,369	5,358	582,493
04-2019	397,209	115,460	16,843	3,001	845	286	369	534,013
05-2019	511,746	26,592	2,706	1,043	472	298	572	543,429
06-2019	493,454	6,675	1,362	619	310	186	266	502,872
07-2019	489,181	4,258	898	380	182	83	137	495,119
08-2019	520,798	6,261	1,266	578	371	213	387	529,874
09-2019	459,737	28,451	2,843	693	284	127	257	492,392
10-2019	284,536	202,401	77,330	25,099	8,415	3,103	2,707	603,591
11-2019	65,979	139,639	150,439	97,267	49,264	22,172	19,833	544,593
12-2019	51,793	119,796	149,410	108,146	60,676	29,290	27,602	546,713
01-2020	60,823	143,152	167,873	112,527	57,129	26,024	22,967	590,495
02-2020	85,024	176,977	148,375	80,874	35,860	14,614	12,058	553,782
03-2020	162,202	230,276	109,364	35,045	10,455	3,545	2,849	553,736
04-2020	267,131	214,264	68,385	18,621	5,618	2,019	1,975	578,013
05-2020	482,794	46,999	5,231	1,527	732	402	847	538,532
06-2020	495,846	6,890	1,552	692	374	172	291	505,817
07-2020	511,676	5,104	1,108	440	217	126	179	518,850
08-2020	506,943	7,517	1,460	699	421	245	431	517,716
09-2020	494,675	44,825	5,052	1,072	408	200	407	546,639
10-2020	332,700	210,819	58,326	15,046	4,464	1,623	1,467	624,445
11-2020	89,591	168,569	129,823	64,812	27,559	10,878	9,032	500,264
12-2020	54,097	119,618	161,480	125,959	74,971	38,249	38,578	612,952
01-2021	41,955	94,500	137,625	119,059	77,856	44,142	49,290	564,427
02-2021	61,464	138,767	142,404	94,519	51,615	25,158	24,577	538,504
03-2021	204,163	243,417	100,650	31,149	9,910	3,560	3,008	595,857
04-2021	382,561	154,133	27,831	5,448	1,473	563	642	572,651
05-2021	513,154	37,084	4,120	1,353	639	373	660	557,383
06-2021	503,685	7,264	1,697	788	397	186	346	514,363
07-2021	516,083	5,572	1,464	722	357	184	280	524,662
08-2021	502,620	5,978	1,326	684	374	200	359	511,541
09-2021	511,097	14,081	1,705	535	308	186	350	528,262
10-2021	340,425	178,647	53,764	15,608	5,124	1,919	1,904	597,391
11-2021	82,223	166,195	144,822	78,587	35,231	14,326	11,603	532,987
12-2021	61,764	136,652	163,406	117,188	65,114	32,477	33,337	609,938
01-2022	33,009	75,604	115,651	106,094	74,203	45,117	54,840	504,518
Average	**278,954**	**104,029**	**73,443**	**44,459**	**23,662**	**11,600**	**11,693**	**547,839**

Residential Non- Heating

Month/Year	0-51 CCF	51-100 CCI	100-151 C(	151-201 C(	201-251 C(	251-301 C(	> 300 CCF	Total Customers
10-2018	26,066	257	25	6	2	2	3	26,361
11-2018	23,944	888	37	10	3	3	7	24,892
12-2018	23,267	1,069	11	3	1	3	7	24,361
01-2019	25,380	1,365	114	15	5	1	9	26,889
02-2019	22,200	994	51	14	4	4	7	23,274
03-2019	26,382	448	23	6	5	2	7	26,873
04-2019	24,224	161	12	4		4	5	24,410
05-2019	25,682	99	29	12	9	8	14	25,853
06-2019	24,622	91	24	14	6	8	8	24,773
07-2019	24,258	43	22	6	4	2	2	24,337
08-2019	26,397	81	25	15	7	6	11	26,542
09-2019	22,637	68	15	6	2	1	6	22,735
10-2019	27,149	228	11	3		1	8	27,400
11-2019	23,257	947	27	7	3	3	8	24,252
12-2019	23,453	1,123	58	11	4	1	11	24,661
01-2020	24,967	1,056	68	9	7	2	12	26,121
02-2020	23,590	790	37	6	2	4	9	24,438
03-2020	24,371	505	24	6	2		6	24,914
04-2020	25,686	411	37	14	1	6	4	26,159
05-2020	24,811	123	29	20	19	5	15	25,022
06-2020	24,463	94	24	18	6	4	9	24,618
07-2020	24,922	71	19	10	5	3	4	25,034
08-2020	24,805	69	29	18	12	6	9	24,948
09-2020	24,818	82	16	5	5	5	8	24,939
10-2020	27,475	204	12	4	4	1	6	27,706
11-2020	21,850	711	20	6			7	22,594
12-2020	26,214	1,514	98	24	11	7	13	27,881
01-2021	22,943	1,428	216	45	18	6	15	24,671
02-2021	22,120	1,056	144	39	14	9	20	23,402
03-2021	25,927	510	41	14	4	3	8	26,507
04-2021	24,773	176	25	7	3	5	6	24,995
05-2021	24,497	124	38	29	11	2	11	24,712
06-2021	24,034	99	36	16	7	2	5	24,199
07-2021	24,780	85	31	16	3	2	8	24,925
08-2021	24,017	82	31	10	6	4	7	24,157
09-2021	23,987	69	15	13	2		6	24,092
10-2021	25,901	299	49	12	1	3	8	26,273
11-2021	21,588	1,053	218	16	10	3	9	22,897
12-2021	24,722	1,414	486	72	22	10	19	26,745
01-2022	18,969	1,248	446	224	77	22	24	21,010
Average	**24,379**	**528**	**67**	**20**	**8**	**4**	**9**	**25,014**

UGI Utilities, Inc. - Gas Division

ALL LOW INCOME - HEATING

Month/Year	0-51 CCF	51-100 CCF	100-151 CCF	151-201 CCF	201-251 CCF	251-301 CCF	> 300 CCF	Total Customers
10-2018	5,230	8,306	5,219	2,251	872	335	236	22,449
11-2018	1,152	3,182	4,808	5,022	3,614	1,973	1,921	21,672
12-2018	919	2,649	4,551	4,929	3,920	2,260	2,213	21,441
01-2019	705	2,107	3,736	4,486	4,468	3,305	4,432	23,239
02-2019	882	2,653	4,348	4,781	3,770	2,292	2,261	20,987
03-2019	3,655	7,723	6,356	3,512	1,494	603	413	23,756
04-2019	12,275	7,646	1,532	267	61	24	13	21,818
05-2019	20,317	2,139	126	26	6	3	1	22,618
06-2019	20,461	303	23	4	2	1	1	20,795
07-2019	19,862	137	21	4	2		1	20,027
08-2019	21,197	322	21	5	2		5	21,552
09-2019	18,023	2,265	253	41	14		5	20,601
10-2019	8,057	9,107	4,902	2,003	748	239	165	25,221
11-2019	1,442	4,055	5,690	5,380	3,697	2,012	1,728	24,004
12-2019	1,256	3,775	5,903	6,165	4,627	2,736	2,523	26,985
01-2020	1,416	4,443	6,687	6,602	4,503	2,451	2,055	28,157
02-2020	2,205	5,914	7,254	5,884	3,357	1,559	1,075	27,248
03-2020	4,808	9,872	7,648	3,383	1,151	363	211	27,436
04-2020	8,270	11,340	5,728	1,885	589	183	117	28,112
05-2020	22,405	4,013	413	60	12	6	11	26,920
06-2020	24,649	358	22	9	7		5	25,050
07-2020	24,907	193	14	5	8	1	3	25,131
08-2020	25,163	475	32	2	11	1	6	25,690
09-2020	22,164	4,183	515	71	20	3	7	26,963
10-2020	12,015	12,709	5,252	1,630	465	162	98	32,331
11-2020	2,725	6,811	7,518	5,309	2,761	1,142	914	27,180
12-2020	1,469	3,841	6,333	7,068	5,707	3,613	3,832	31,863
01-2021	1,175	3,037	5,336	6,150	5,448	3,961	4,993	30,100
02-2021	1,810	4,682	6,559	6,248	4,466	2,611	2,723	29,099
03-2021	6,612	11,922	8,128	3,393	1,212	419	277	31,963
04-2021	15,142	11,614	3,057	596	128	37	22	30,596
05-2021	25,860	3,647	315	59	17	3	11	29,912
06-2021	27,051	394	34	17	3	1	7	27,507
07-2021	27,716	263	20	10	3	1	6	28,019
08-2021	27,160	328	22	8	5	3	8	27,534
09-2021	26,522	1,458	121	20	9	2	6	28,138
10-2021	12,264	9,317	3,608	1,217	450	170	118	27,144
11-2021	2,249	5,188	6,567	5,139	3,042	1,392	971	24,548
12-2021	1,544	3,891	6,011	6,020	4,316	2,679	2,760	27,221
01-2022	740	2,043	3,474	4,292	4,143	3,227	4,712	22,631
Average	**11,587**	**4,458**	**3,454**	**2,599**	**1,728**	**1,105**	**1,022**	**25,841**

ALL LOW INCOME - NON-HEATING

Month/Year	0-51 CCF	51-100 CCF	100-151 CCF	151-201 CCF	201-251 CCF	251-301 CCF	> 300 CCF	Total Customers
10-2018	445	12	1					458
11-2018	394	32	1					427
12-2018	380	40	1					421
01-2019	402	43	6					451
02-2019	351	38	1					390
03-2019	461	20						481
04-2019	431	7						438
05-2019	483	1						484
06-2019	472	1						473
07-2019	476							476
08-2019	509							509
09-2019	477							477
10-2019	517	8						525
11-2019	473	28	1			1		503
12-2019	488	35			1		1	525
01-2020	501	29	2				1	533
02-2020	495	31	1	1			1	529
03-2020	509	22		1				532
04-2020	527	14		1				542
05-2020	529	5						534
06-2020	528	1						529
07-2020	541	2						543
08-2020	541	1						542
09-2020	534	2						536
10-2020	656	5	1					662
11-2020	580	23		1				604
12-2020	621	52	1	1				675
01-2021	581	45	6		1		1	634
02-2021	536	31	7	3	2			579
03-2021	649	20	4					673
04-2021	628	11	2					641
05-2021	627	2	1	1				631
06-2021	608	1	2	1				612
07-2021	617	1	1					619
08-2021	619	2						621
09-2021	620	1						621
10-2021	551	5	3	2				561
11-2021	485	28	6	1	2			522
12-2021	505	29	11	6	3	1	2	557
01-2022	401	30	10	6		1	1	449
Average	**519**	**18**	**3**	**2**	**2**	**1**	**1**	**538**

UGI Gas Exhibit DVA-6R

UGI Utilities, Inc.

CAP Exits

Reason Removed	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20
Inactive - Removed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Left Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Shut Off/Nonpayment	0	0	0	0	497	22	20	36	15	7	103	188	62	42	30	9	12	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Moved	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Over Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - No Benefit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Graduated	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Failure to recertify	0	3	2	2	4	0	4	2	4	6	5	28	5	8	4	9	0	59	2	10	19	38	34	6	24	81	65	89	84
Removed - Failure to reduce usage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	24	0	0	7	0	0	0	0	0
Removed - Failure to apply for LIHEAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Failure to apply for LIURP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Non payment	0	0	6	26	4	1	6	2	5	1	3	0	2	3	26	5	0	2	0	138	16	11	37	3	13	5	3	5	0
Removed - No access to meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Unauthorized usage	0	1	0	0	0	0	0	0	1	0	0	0	1	0	2	1	0	0	0	0	2	1	1	0	1	0	0	2	0
Removed - Fraud	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	1	0	0	0	0
Removed - Bankruptcy	0	1	0	0	1	2	2	1	3	2	2	1	1	1	1	0	0	0	1	1	0	2	0	2	2	1	0	1	2
Removed - Customer moved	109	261	399	184	221	227	188	223	221	245	276	294	264	322	320	196	152	322	210	266	387	324	415	327	278	322	286	389	391
Removed - Deceased	0	1	0	1	1	4	1	5	4	4	8	8	1	4	4	2	2	2	4	3	12	3	2	5	4	6	6	3	7
Removed - Seasonal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - No Benefit	11	43	25	10	3	4	8	10	6	3	11	10	36	170	9	3	2	0	0	8	3	6	7	5	5	2	50	52	4
Removed-Choose P/A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	27	10	18	47	31	71	39	16	1	3
Removed - Active collections	0	0	0	0	0	1	3	2	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Over income	14	6	4	6	1	13	19	19	30	24	23	21	33	24	13	16	17	33	34	21	19	21	28	24	26	25	19	32	21
Removed - Head of household not residing in the home	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	1	2	2	1	1	0	1	0	0
Removed - Invalid customer class - Health care facility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0	0
Removed - Invalid customer class - Foreign load	1	0	1	1	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Rate payer occupant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Landlord Tenant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Pool Heater	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Commercial Property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Customer Choice	0	0	0	0	2	0	1	1	0	0	0	1	0	0	1	0	0	0	0	4	0	0	0	0	0	0	0	0	0
Total	**135**	**317**	**437**	**230**	**734**	**274**	**253**	**302**	**290**	**293**	**431**	**551**	**406**	**574**	**411**	**242**	**188**	**419**	**276**	**479**	**493**	**426**	**573**	**412**	**426**	**481**	**447**	**574**	**512**

UGI Utilities, Inc.- Gas Division
CAP Exits by Reason

Reason Removed	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Removed - Failure to recertify	60	3	10	43	38	34	13	24	81	65
Removed - Failure to reduce usage	0	0	0	0	0	0	0	0	0	0
Removed - Failure to apply for LIHEAP	0	0	0	0	0	0	0	0	0	0
Removed - Failure to apply for LIURP	0	0	0	0	0	0	0	0	0	0
Removed - Non payment	2	0	138	16	11	37	3	14	9	3
Removed - No access to meter	0	0	0	0	0	0	0	0	0	0
Removed - Unauthorized usage	0	0	0	2	1	1	0	1	0	0
Removed - Fraud	0	0	0	0	0	0	1	1	0	0
Removed - Bankruptcy	0	1	1	0	2	0	2	2	1	0
Removed - Customer moved	322	212	265	387	324	415	328	278	322	286
Removed - Deceased	2	4	3	12	4	2	5	4	6	6
Removed - Seasonal	0	0	0	0	0	0	0	0	0	0
Removed - No Benefit	0	0	8	3	6	7	5	5	2	50
Removed - Choose P/A	0	25	27	10	18	47	31	71	38	16
Removed - Over income	33	34	21	19	21	28	24	26	25	19
Removed - Head of household not residing in the home	0	0	0	1	2	2	1	1	0	1
Removed - Invalid customer class	1	0	5	0	0	0	0	0	0	1
Total	**420**	**279**	**478**	**493**	**427**	**573**	**413**	**427**	**484**	**447**

Reason Removed	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Removed - Failure to recertify	89	84	92	0	1	0	0	0	0	0	0	0
Removed - Failure to reduce usage	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Failure to apply for LIHEAP	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Failure to apply for LIURP	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Non payment	5	0	1	0	0	0	0	1	0	0	0	0
Removed - No access to meter	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Unauthorized usage	2	0	0	0	0	0	0	0	0	0	0	0
Removed - Fraud	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Bankruptcy	1	2	3	1	1	1	1	1	0	2	1	0
Removed - Customer moved	389	391	389	233	185	244	276	283	301	318	287	299
Removed - Deceased	3	7	5	4	6	9	4	4	6	6	1	2
Removed - Seasonal	0	0	0	0	0	0	0	0	0	0	0	0
Removed - No Benefit	52	4	2	4	10	9	5	1	2	2	2	1
Removed - Choose P/A	1	3	5	1	1	0	1	0	2	0	0	0
Removed - Over income	32	21	21	9	17	30	14	14	15	39	32	22
Removed - Head of household not residing in the home	0	0	2	0	0	0	1	0	0	2	0	0
Removed - Invalid customer class	0	0	0	1	0	1	0	0	0	1	0	0
Total	**574**	**512**	**520**	**253**	**221**	**294**	**302**	**304**	**326**	**370**	**323**	**324**

Reason Removed	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Removed - Failure to recertify	0	0	0	0	2	1	1359	562	38	53	87	878
Removed - Failure to reduce usage	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Failure to apply for LIHEAP	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Failure to apply for LIURP	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Non payment	0	0	0	0	1	2	18	13	8	3	138	0
Removed - No access to meter	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Unauthorized usage	0	0	0	0	0	0	2	1	0	1	0	0
Removed - Fraud	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Bankruptcy	0	0	0	2	1	2	1	0	2	0	0	0
Removed - Customer moved	213	265	312	279	311	331	308	310	344	317	330	283
Removed - Deceased	6	3	7	5	8	15	5	6	11	5	6	6
Removed - Seasonal	0	0	0	1	0	0	0	0	0	0	0	0
Removed - No Benefit	0	1	4	6	10	37	42	16	6	4	3	0
Removed - Choose P/A	0	0	2	13	135	272	152	95	127	85	44	7
Removed - Over income	33	36	43	66	98	82	69	69	58	35	51	55
Removed - Head of household not residing in the home	0	0	1	1	1	1	0	2	0	1	2	0
Removed - Invalid customer class	0	1	0	0	0	4	0	0	0	0	0	1
Total	**252**	**306**	**369**	**373**	**567**	**747**	**1956**	**1074**	**594**	**504**	**661**	**1230**

Reason Removed	Jan-22
Removed - Failure to recertify	1384
Removed - Failure to reduce usage	2
Removed - Failure to apply for LIHEAP	0
Removed - Failure to apply for LIURP	0
Removed - Non payment	0
Removed - No access to meter	0
Removed - Unauthorized usage	1
Removed - Fraud	0
Removed - Bankruptcy	2
Removed - Customer moved	225
Removed - Deceased	6
Removed - Seasonal	0
Removed - No Benefit	0
Removed - Choose P/A	3
Removed - Over income	37
Removed - Head of household not residing in the home	1
Removed - Invalid customer class	0
total	**1661**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 1-SR

Surrebuttal Testimony of
Christopher R. Brown

Topics Addressed: ***Pro Se*** **Complainants and Public Input Hearings**

Dated: May 27, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher R. Brown. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 1, on January 28, 2022, and my rebuttal testimony, UGI Gas Statement No. 1-R, on May 17, 2022.

Q. What is the purpose of your surrebuttal testimony?

A. My testimony responds to certain portions of the rebuttal testimony of Office of Consumer Advocate ("OCA") witness Roger D. Colton (OCA St. No. 4-R).

Q. Are you sponsoring any exhibits as part of your surrebuttal testimony?

A. No.

II. *PRO SE* COMPLAINANTS AND PUBLIC INPUT HEARINGS

Q. In your rebuttal testimony, you addressed the testimony of *pro se* complainants at the public input hearings. Did any other party witness address that testimony in rebuttal?

A. Yes. OCA witness Colton's rebuttal testimony (OCA St. No. 4-R) responded to the testimony of Lisa Musser and Ruth Weaver, both of whom testified at the 1:00 PM session of the public input hearings on April 13, 2022.

Q. Do you have any general observations about Mr. Colton's rebuttal testimony?

A. Yes. Mr. Colton states that the testimony of Ms. Musser and Ms. Weaver purportedly "affirms," "supports," and "expands" on his direct testimony. (OCA St. No. 4-R, pp. 2, 5.)

Q. What response did Mr. Colton have to Ms. Musser's public input hearing testimony?

A. Mr. Colton observes how Ms. Musser raised concerns about her natural gas bill increasing despite allegedly decreasing her natural gas consumption. (OCA St. No. 4-R, p. 2.) Mr. Colton then cites the U.S. Department of Energy's ("DOE") October 2021 "Short Term Energy Outlook," as support for the natural gas heating costs increasing during the winter of 2021-2022. (OCA St. No. 4-R, pp. 2-3.) Despite "many, if not most, analysts expect[ing] that fly-up in price to be a short-term anomaly," Mr. Colton believes other factors may keep natural gas commodity prices higher. (OCA St. No. 4-R, p. 3.) Therefore, according to Mr. Colton, "Ms. Musser's concerns about the impact of adding an increase in distribution rates on top of these other price increases are well-founded." (OCA St. No. 4-R, p. 3.) Lastly, Mr. Colton points to Ms. Musser's testimony as support for concerns being "applicable to those households who may have income sufficiently high to be no longer income-eligible for universal service programs such as CAP and LIHEAP, but is sufficiently low to be unable to afford their UGI Gas bill." (OCA St. No. 4-R, pp. 3-4.)

Q. What response did Mr. Colton have to Ms. Weaver's testimony?

A. Mr. Colton similarly notes Ms. Weaver's concerns about the proposed increase for the residential customer charge and how she is ineligible for the Company's customer assistance programs. (OCA St. No. 4-R, pp. 5-6.)

Q. Would you please respond to Mr. Colton's arguments?

A. First, as I stated in my direct testimony (UGI Gas St. No. 1), the proposed customer charge, and resulting bill impact to residential customers, is fair and reasonable because it supports the Company's ongoing need to support the provision of safe and reliable service to customers. (UGI Gas St. No. 1 at 7.) Moreover, the proposed customer charge compares favorably to other customers in Pennsylvania on a total bill basis. (*Id.*) While Mr. Colton fails to acknowledge it, the Company is making substantial distribution system investments needed to replace aging infrastructure on an accelerated basis, as well as upgrade and modernize distribution system segments – all needed to support system safety and reliability. (*Id.* at 8.) In terms of cost causality, the proposed customer charge reasonably reflects cost-of-service principles, while considering gradualism of rate design. (*Id.* at 7-8.)

Second, the residential customer charge is the optimum recovery method for Rate R/RT customers' direct customer costs. As explained in the rebuttal testimony of UGI Gas witness Heppenstall, "[t]he schedule in Exhibit D-R shows that the Company can justify customer charges for Rate R/RT customers of $27.79 per month and $46.26 [per month] for Rate N/NT customers, using only direct customer costs." (UGI Gas St. No. 10-R at 10.) Those "justifiable levels are higher than the customer charges proposed by the Company of $19.95 for Rate R/RT and $30.00 for Rate N/NT." (*Id.*) Mr. Colton continues to propose that a substantial portion of the direct customer costs for Rate R/RT be recovered through the Company's volumetric charges. However, as UGI Gas witness Taylor explained, the Company's proposed increase in the residential customer charge will actually lower the average bill for low-income and CAP customers. (UGI Gas St. No. 11-R at 33.)

Third, the natural gas commodity charges on UGI Gas's natural gas bills are not at issue in this proceeding. For non-shopping customers, the Company's Purchased Gas Cost ("PGC") rates and gas procurement practices are the subject of its separate annual proceeding pursuant to Section 1307(f) of the Public Utility Code. For shopping customers, the rates they pay for competitive natural gas service are subject to the terms and conditions set forth in the contracts with their natural gas suppliers, and the Commission does not regulate those rates. This proceeding is solely focused on whether the Company's proposed increase in distribution base rates is just and reasonable and should be approved.

Fourth, I disagree with Mr. Colton's conclusion that the proposed base rate increase will unfairly burden non-low-income customers. If the rate increase causes an increase in the number of payment-troubled customers, the Company would solicit those customers for participation in CAP, or the customer could contact the Company on their own. There are also programs other than CAP that assist customers facing temporary difficulty paying their utility bills, such as the hardship grants offered by Operation Share, and federal crisis grants offered by LIHEAP. As such, the Company maintains its Operation Share program, which can provide grants to certain customers outside of the income requirements of CAP or LIHEAP. The Company also voluntarily implemented an Energy Efficiency and Conservation ("EE&C") Plan, so that its customers and the Commonwealth as a whole would benefit from measures that reduce the consumption of natural gas. I would encourage any customers who do not qualify for CAP or LIHEAP to see if the Company's EE&C programs can help them implement measures that reduce their natural gas consumption and, by extension, their natural gas service bills.

Q. Mr. Colton claims that the testimony of Ms. Musser and Ms. Weaver "provide[s] compelling personal real-life examples of the need for the Commission to adopt each recommendation set forth in [his] Direct Testimony." (OCA St. No. 4-R, p. 7.) Do you agree?

A. No. As explained in the rebuttal testimony of UGI Gas witness Epler (UGI Gas St. No. 8-R at 17-20)[1], Heppenstall (UGI Gas St. No. 10-R at 10)[2], Taylor (UGI Gas St. No. 11-R at 8-10, 24-27, 29-34)[3], and Adamo (UGI Gas St. No. 12-R at 3-31, 42-45, 48-50), Mr. Colton's proposals should be rejected. Nothing in the testimony of Ms. Musser and Ms. Weaver or in Mr. Colton's rebuttal testimony changes the Company's position on Mr. Colton's recommendations.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

1 Ms. Epler's rebuttal testimony details the support needed to justify the Company's proposed customer charge in this proceeding.

2 Ms. Heppenstall's rebuttal explains that the Company's cost of service study supports a higher residential customer charge than the Company is proposing in this case.

3 Mr. Taylor's rebuttal explains the benefits that the Weather Normalization Adjustment ("WNA") and budget billing provides customers, demonstrates that the proposed customer charge comports with the concept of gradualism, and does not negatively impact conservation.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 1-RJ

Rejoinder Testimony of Christopher R. Brown

Topics Addressed: **Management Performance**
NRG Issues
Issues Impacting Competitive Customers

Dated: June 1, 2022

23980501v1

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher R. Brown. My business address is 1 UGI Drive, Denver, PA 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 1, on January 28, 2022. I also submitted my rebuttal testimony, UGI Gas Statement No. 1-R, on May 17, 2022.

Q. What is the purpose of your rejoinder testimony?

A. My testimony responds to certain portions of the surrebuttal testimony and exhibits of: (1) Bureau of Investigation and Enforcement ("I&E") witness Anthony Spadaccio (I&E St. No. 2-SR); (2) Office of Consumer Advocate ("OCA") witness Jerome D. Mierzwa (OCA St. No. 3-SR); (3) Office of Small Business Advocate ("OSBA") witness Robert D. Knecht (OSBA St. No. 1-S); and (4) NRG Energy, Inc. ("NRG") witness Christopher Reyes (NRG St. No. 1-SR).

II. OVERVIEW OF COMPANY'S CASE

Q. Do any positions taken by other parties in their witnesses' surrebuttal testimony change the Company's positions?

A. No. The Company's position on revenue requirement, rate design, low-income issues, and other issues remain unchanged from UGI Gas's rebuttal testimony.

III. MANAGEMENT PERFORMANCE

Q. Do any parties provide surrebuttal testimony on the management performance adjustment proposed by the Company?

A. Yes, I&E witness Spadaccio and OCA witness Garrett both provide surrebuttal testimony continuing to argue that the Commission should not adopt a management performance adder for UGI Gas. For the most part, their arguments repeat claims they made in direct testimony and which I have already provided a response. However, I&E's testimony does raise new arguments that I will address.

Q. On page 38 of his surrebuttal testimony, Mr. Spadaccio argues that the Commission should not consider ratepayer funded initiatives in granting a management performance adjustment. Do you agree?

A. No, I do not. And, more importantly, it is clear that the Commission does not agree with Mr. Spadaccio's interpretation. As referenced by Mr. Spadaccio, the programs identified by the Commission in its 2018 UGI Electric Rate Case Order are programs funded by ratepayers. Mr. Spadaccio has not and cannot point to any statutory language or Commission order stating that the management performance adjustment may only be permitted where the utility has shown that no ratepayer funds were used. Further, Mr. Spadaccio wrongly insists that programs considered in support of the management performance adjustment must "reduce costs to benefit ratepayers." (I&E St. No. 2-SR, p. 38.) Nothing in 66 Pa C.S. §523 requires a showing of cost reductions to ratepayers. Lacking support for his claims, Mr. Spadaccio's arguments must be rejected.

Q. Mr. Spadaccio argues that the Company's reliance on the 2018 UGI Electric Rate Case determination on management performance shows that UGI Gas should only receive a 5 basis point adjustment rather than the full 20 basis point adjustment. (I&E St. No. 2-SR, p. 37). What is the Company's response?

A. The Commission maintains discretion on any level of management performance adjustment and should consider the fact-specific elements of each case in making such adjustments. In this case, the Company has identified numerous reasons for awarding a management performance adjustment, including several which were not included in the UGI Electric case referenced by Mr. Spadaccio. It is also worth noting that Mr. Spadaccio's own testimony shows how he recognizes that his outright rejection of the management performance adjustment is inconsistent with Commission precedent. Mr. Spadaccio actually notes several instances in which the Commission has approved management performance adjustments. (*See* I&E St. No. 2-SR at 36). Moreover, he states "it is nonsensical to support the idea that since ratepayers fund the initiatives and accomplishments Mr. Brown mentions, ratepayers should then in turn fund a higher equity return for UGI Gas' investors." (I&E St. No. 2-SR at 35.) Despite Mr. Spadaccio's belief, the Commission has awarded basis points under these circumstances and the Company believes that it is logical for the Commission to do so here.

IV. NRG ISSUES

A. STANDARDS OF CONDUCT

Q. Do you have any initial response regarding Mr. Reyes's surrebuttal testimony on the Standards of Conduct?

A. Yes, I do. Mr. Reyes repeats many of the arguments raised in his direct testimony, but he does not provide any new facts or allegations suggesting that UGI Gas has done anything improper that should be remedied by the Commission in this proceeding. Importantly, Mr. Reyes admits that he has no specific allegations when he states that his concerns in this proceeding are driven "solely by the fact that UGI has an affiliated supplier competing in the retail market…" (NRG St. 1-SR, pp. 3-4.) However, the existence of an affiliate is simply not a basis for further investigation by the Commission.

Q. Mr. Reyes states that shared employees "raises a concern about the optics" that the Commission should address. (NRG St. No. 1-SR, p. 4.) What is your response?

A. Section 62.142(a)(13) of the Commission's specifically allows shared employees and provides only that "employees who have responsibility for operating the distribution system, including natural gas delivery or billing and metering, as well as those responsible for marketing and customer service, may not be shared." 52 Pa. Code § 62.142(a)(13). UGI Gas does not share any employees that have responsibility for operating the distribution system, gas deliveries, billing, metering, marketing or customer service. To the extent that the "optics" Mr. Reyes is concerned about are the sharing of any employees at all, his interpretation of the Standards of Conduct is incorrect and is not a basis for further Commission investigation.

Q. Mr. Reyes discusses the Commission's audit findings and asserts that its findings support the greater scrutiny requested by NRG in this proceeding. (NRG St. No. 1-SR, p. 6.) Do you agree?

A. No, just the opposite is true. The findings made in the audit show that the Commission is already reviewing broad compliance by the Company in all affiliate business transactions to ensure proper cost allocations and prevent competitive market distortions. I note that Mr. Reyes is mistaken in his testimony where he claims that there is no verification that UGI Gas has undertaken the measures identified in the audit. As I stated in my rebuttal testimony, the Company submits annual status update reports demonstrating its compliance with its Audit Implementation Plan approved in the 2018 Management Efficiency Audit[1], the most recent of which was filed in December 2021, and which have provided the Commission with numerous opportunities to verify that UGI Gas has complied with the audit requirements. Without any fact-based allegations, there is no basis for the Commission to conclude that its existing monitoring activities are insufficient.

B. AUTOMATION OF SUPPLIER NOTIFICATIONS

Q. What claims does Mr. Reyes make regarding the need for automated supplier notifications for weekend deliveries on the UGI Gas system?

A. Mr. Reyes asserts three specific claims in his surrebuttal testimony that he believes supports his claim that UGI Gas should adopt an automated process for notifying suppliers of what he describes as "utility cuts" over the weekend. Specifically, Mr. Reyes argues

[1] See Docket Nos. D-2018-3002234, D-2018-3002235 and D-2018-3002236.

that this is necessary to safeguard the system, that it is standard industry practice to send notifications seven days per week, and that the Company may impose punitive penalties associated with these cuts. (NRG St. No. 1-SR, p. 9.)

Q. Has Mr. Reyes identified any issue that would require the Company to further "safeguard" the UGI Gas distribution system?

A. No. It is important to understand for clarity that UGI Gas maintains broad monitoring, contingency, communication, and emergency planning, which are focused on the identification, assessment, and response to any situation which might be necessary to safeguard the UGI Gas distribution system. UGI Gas maintains the ability to issue Operational Flow Orders to all suppliers on its system on a 24/7/365 basis. Mr. Reyes's concerns here are not of that nature. In fact, when UGI Gas reviewed this issue, it was unable to find any instance where weekend cuts were initiated by the utility or where they, even remotely, required action to safeguard the UGI Gas distribution system.

Q. Mr. Reyes claims that "it is standard industry practice for utilities to alert entities when a nomination is not confirmed" and "[e]very other utility with which [he] transact[s] sends notifications seven days per week." (NRG St. No. 1-SR, p. 9.) What is your response?

A. UGI Gas is not aware of any other utilities that undertake this activity, but in response to a discovery question, Mr. Reyes only mentions "Keyspan New York"[2] as a utility that

2 I believe Mr. Reyes means KeySpan Gas East Corporation d/b/a National Grid. I will hereinafter refer to the utility as "KeySpan."

manually makes cuts and sends automated emails. (*See* UGI Gas Exhibit CRB-1RJ, a copy of NRG's discovery response UGI-NRG-I-9.) I am personally unaware of the details of KeySpan process, and Mr. Reyes did not provide any details as part of his response to Company discovery. Accordingly, the Company is unable to evaluate if such similar process is appropriate or workable for the Company. However, given Mr. Reyes only identified one utility – KeySpan – I can only conclude that Mr. Reyes's assertion of this being an industry standard practice is not supported. Therefore, the Commission should not direct UGI Gas to adopt a solution for a problem that has not been substantiated based on the facts presented in this case.

Q. Mr. Reyes expresses concern about penalties. (NRG St. No. 1-SR, pp. 9-10.) Please respond.

A. UGI Gas is not aware of any penalties that it has assessed based on utility cuts. Further, Mr. Reyes did not identify in testimony or discovery any penalties or costs NRG has incurred as a result of cuts on the UGI Gas system. The Commission should not rely on the unsubstantiated specter of penalties as the basis for adopting a potentially costly modification to the Company's system.

Q. Mr. Reyes states that the nomination deadline on Fridays is unrelated to weekend cut notifications. (NRG St. No. 1-SR, p. 9.) How do you respond?

A. Mr. Reyes is seeking the same courtesy notification (described in my rebuttal, UGI Gas St. No. 1-R at 25) of mismatches between supplier nominations to UGI Gas as compared to nominations made on the interstate pipelines, that UGI Gas provides during the normal weekday courtesy process. If NRG can provide ongoing timely nominations, as they do on occasion, UGI Gas can provide the level of service Mr. Reyes is seeking and discussed in my rebuttal testimony. (*Id*.) In his surrebuttal, Mr. Reyes mentions that his company is often still waiting for information from their suppliers at 2 p.m. on Fridays at the UGI Gas nomination deadline. This again appears to be an issue between NRG and their suppliers, that Mr. Reyes is, inappropriately, looking for UGI Gas to solve. Moreover, as I stated in my rebuttal, the Company is unaware of: (1) any other suppliers with this concern; (2) any weekend cuts occurring due to a mismatch between supplier nominations; and (3) the frequency upon which NRG's alleged problem has occurred. (UGI Gas St. No. 1-R at 23-24.)

Q. Do you have any final comments on Mr. Reyes's proposal regarding weekend utility cuts?

A. Yes. Mr. Reyes initially focuses his testimony on automated notifications, but later indicates that the Company's weekend schedulers should be providing the notifications in manual form. The Company is unable to formulate a solution to a problem which Mr. Reyes has been unable to articulate with clear instances of occurrence, a clear functional definition from a system perspective that could support an automated solution, or a clear indication as to if it is truly a process that can be achieved by modification to manual processes.

C. WEIGHTED AVERAGE COST OF DELIVERED GAS

Q. In his surrebuttal testimony, Mr. Reyes asks the Company to show the impact of each pipeline rate case along with a 12-month forward estimate of the rate change. (NRG St. No. 1-SR, p. 10.) Is it possible to calculate that impact with any reasonable degree of accuracy?

A. No, it is not. Taking the recent Columbia Gas Transmission ("Columbia") rate case at Docket No. RP20-1060 as an example, that pipeline implemented its as-filed rates on February 1, 2021. If UGI Gas provided a 12-month forward projection of WACOD impacts, it would have overstated the impacts because the settlement rates went into effect on November 1, 2021, only 9 months later. Even once the settlement rates went into effect, within the following 7 months, the WACOD was updated for Columbia's modernization tracker increase, other surcharges that increase annually, and the WACOD will be lowered in the coming months to reflect the refund that was received by UGI Gas from Columbia in April 2022. And, these are the adjustments for just one of the pipelines that impact the WACOD. Further, in addition to the pipeline adjustments, the WACOD is also adjusted monthly for changing delivery requirements from participating customers and suppliers. While Mr. Reyes's request may sound simple, a 12-month projection provided by the Company could ultimately be significantly different from the WACOD at the end of that period and could be confusing to some suppliers.

Q. Mr. Reyes claims that NRG is not requesting UGI Gas to undertake any work beyond what it is already doing on the WACOD. (NRG St. No. 1-SR, p. 11.) Please respond.

A. Based on the description Mr. Reyes includes in his surrebuttal testimony, I believe that

UGI Gas is already providing information of the type that NRG seeks. In the spring of 2022, UGI Gas adopted a new process for providing WACOD updates that included specific explanations of new adjustments incorporated each month, and the period over which the adjustment will be reflected when that information is known. Based on Mr. Reyes's surrebuttal testimony, I believe that this generally satisfies the information that he is requesting in this case.

V. ISSUES IMPACTING COMPETITIVE CUSTOMERS

A. CAPACITY ASSIGNMENT

Q. OCA witness Mierzwa disagrees with the Company's procedures for capacity releases of Columbia to Rate XD customers. Mr. Mierzwa claims in his surrebuttal testimony that the Company's current methodology provides an unreasonable and discriminatory discount to these customers. (OCA St. 3-SR, pp. 16-17.) What is your response?

A. Mr. Mierzwa's claims are not substantiated by the facts. All of the customers that currently receive a release of capacity on Columbia have been receiving that capacity for many years. For the vast majority of the years that those customers received the Columbia capacity, they were customers of the legacy UGI Gas, then UGI South. Grandfathering these customers into the integrated utility with their existing service arrangements, including their Columbia capacity release volumes, is not discriminatory, particularly where the customers pay UGI Gas for the entire cost of the capacity released at the price that UGI Gas pays to the pipeline. Additionally, the price difference that Mr. Mierzwa focuses on between the Columbia capacity and the WACOD is driven largely by the recent increase in pipeline Section 4 proceedings at the Federal Energy Regulatory Commission.

Q. Mr. Mierzwa acknowledges that it is possible his modifications would result in subsequent reductions in base rate revenues from the Rate XD class. (OCA St. No. 3SR, p. 17.) Why is the loss of Rate XD revenues harmful to all customers?

A. Based on the Company's cost allocation study, as a customer class, the Rate XD customers pay significantly above the cost to serve them. This directly benefits all other customer classes, and particularly the Rate R/RT customers, because that is the customer class that is the farthest below its cost of service (see UGI Gas Exhibit D, Schedule B page 1 of 1). If the Company were to lose any of its Rate XD customers, or the revenue associated with those customers, it would need to recover the costs being paid by those Rate XD customers from other customer classes. However, Mr. Mierzwa does not propose any solution for recovering the lost revenues associated with his proposal on a timely basis as part of this case.

Q. Mr. Mierzwa also states that under his proposal, transportation customers that do not accept an assignment of capacity would bear some responsibility for the capacity cost and distribution charge discounts granted to Rate XD customers. (OCA St. No. 3SR, p. 17.) How do you respond?

A. I believe Mr. Mierzwa is mistaken. I do not see how transportation customers, who do not take a capacity assignment from the Company, would be affected by the change proposed by Mr. Mierzwa. As I understand it, under his proposal, only those customers who take capacity from the Company would be impacted by changing what Rate XD customers pay for the Columbia capacity that they are assigned, not those customers who procure their own capacity from the open market.

Q. Mr. Mierzwa claims that your concerns about the loss of these Rate XD customers should be disregarded because you have not provided evidence that there are location options available to these customers where the cost of gas would be comparable to their current service costs. (OCA St. No. 3-SR, p. 18.) Do you agree with Mr. Mierzwa?

A. No. First, it is important to acknowledge that the Commission has long recognized that customers with competitive alternatives are at risk of departing the system and that there is value to all customers in engaging in negotiations to retain them where it is cost effective to do so.[3] Further, I note that Mr. Mierzwa's testimony fails to recognize that these customers have competitive supply alternatives that are regularly assessed by UGI Gas during contract renegotiations. Thus, while relocation is certainly one possibility, it is not the only way that these customers might cease (or reduce) taking gas service from the Company.

Second, these customers are large, sophisticated customers that purchase gas supply in the competitive market. They could avoid the UGI Gas system entirely by directly interconnecting with Columbia's pipeline at any point in the surrounding area. Or, if they were given sufficient incentive to relocate their operations due to the increase in gas costs, they could search for a location outside of Pennsylvania, or even outside the United States.

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3 *See, e.g., Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Distribution System Improvement Charge*, Docket No. P-2012-2338282 (Order entered May 22, 2014) at pp. 57-58.

Some locations may even provide large employers with incentives for relocating.

Third, the Company's competitively situated customers were already considered at risk of leaving the UGI Gas system if the Company does not negotiate an agreeable price for distribution service. In addition, these customers are currently experiencing other intense economic pressures. While Mr. Mierzwa believes that his adjustment, alone, would not provide a sufficient basis for relocation, (OCA St. No. 3-SR, p. 18), his modification will not occur in a vacuum, and he makes no effort to consider the cost of alternative supplies available to these customers and the price threshold where those other alternatives become the most cost-effective option. Mr. Mierzwa provides no analysis showing that with his adjustment, UGI Gas would still be the most competitive supply alternative. Therefore, his proposal should be rejected.

Q. Are there any other likely outcomes that Mr. Mierzwa fails to consider?

A. Yes. Mr. Mierzwa fails to consider that these customers have negotiated rates, and that the Company is already seeking the maximum rates it can obtain when contracts are renegotiated. Therefore, assuming that the increase associated with the WACOD was even an acceptable and sustainable price compared to other supply alternatives, it is very likely that if these customers were required to pay more for capacity, they would simply negotiate to pay less in base rates.

Q. Do you have any further observations about Mr. Mierzwa's proposal?

A. Yes, I do. To the extent that the Commission were inclined to adopt Mr. Mierzwa's proposal that UGI Gas migrate Rate XD customers receiving Columbia capacity releases to the WACOD, it should do so on the condition that the renegotiated contracts be at least revenue neutral from a Company standpoint. If the Commission decides to adopt Mr. Mierzwa's proposal without ensuring that his proposal is only applied to contracts in a way that would be revenue neutral, then the Commission should reduce the Rate XD revenue reflected in this case by the $3.1 million identified by Mr. Mierzwa in his testimony and reallocate the cost of recovery of that $3.1 million to the Rate R/RT customer class.

B. RATE INCREASE ALLOCATION TO RATE CLASSES XD AND IS

Q. In your rebuttal testimony you addressed an issue raised by Mr. Knecht relating to the cost allocation for Rates XD and IS. Did Mr. Knecht respond to your testimony?

A. Yes, OSBA witness Knecht raises two further points in continuing to advance his position that the Company should not adjust the cost allocation for Rate XD and Rate IS customers to reflect the zeroing out of the revenues associated with the Company's Distribution System Improvement Charge ("DSIC") for those customer classes. (OSBA St. No. 1-SR, pp. 6-7.)

Q. Mr. Knecht claims that the Company determines, as part of its negotiations with competitively situated customers that they "can afford to experience rate increases associated with the DSIC." (OSBA St. No. 1-SR, p. 7.) Is this accurate?

A. No, it is not. UGI Gas does not determine what its competitive customers can or cannot pay. Instead, the Company negotiates based on competitive alternatives available to the customer. In its negotiations, the Company attempts to apply the DSIC to these customer classes, consistent with the Commission's determination in its original DSIC proceedings.

Some customers agree through the course of the negotiations to pay the DSIC, and where they do the Company applies the DSIC on a going forward basis.

Q. Mr. Knecht asserts that the Company only applies the DSIC so long as the revenues flow to UGI Gas shareholders. (OSBA St. No. 1-SR, p. 7.) Please respond.

A. As evidenced by the increase in revenues that the Company has reflected in previous rate cases for Rate XD and Rate IS, Mr. Knecht's claim is incorrect. If the Company's Rate XD and Rate IS revenues were flat from rate case to rate case, and only increased between rate cases as a result of the DSIC charges, Mr. Knecht's position may have some merit. However, the increase in Rate XD and Rate IS revenues across the Company's past several rate cases demonstrates that the Company has produced a benefit for all other customer classes on the UGI Gas system. This benefit is a result of successful negotiations with these competitive customers, which work to sweep any possible DISC revenues into base contracts and is not one sided to benefit shareholders.

Q. Mr. Knecht claims that the Commission should not adopt a rate decrease associated with the DSIC revenue adjustment because it is "unusual" for the Commission to adopt rate decreases for certain classes where other classes are experiencing a significant increase. (OSBA St. No. 1-SR, p. 6.) Do you agree?

A. I do not know if it is "unusual" for the Commission to adopt rate decreases for certain classes, and Mr. Knecht provided no support for his overly broad conclusion. However, even assuming Mr. Knecht were correct, this is the unusual situation where it makes sense to do so. Mr. Knecht's argument is rooted in a general assumption about cost allocation, but his adjustment relates to specific revenues that will, for the FPFTY, be zero. When rates go into effect, UGI Gas must set the DSIC rate at zero. During the course of the FPFTY, the DSIC rate will continue to stay at zero until the Company has reached its plant additions for the FPFTY. Incorporating the revenues generated by Rate XD and Rate IS customers in the FTY that will not occur in the FPFTY, which is what Mr. Knecht proposes, will allocate $2 million more costs to these customers than they will generate. The Company will have no ability to recover that $2 million, and therefore Mr. Knecht's methodology will purposefully deprive UGI Gas of $2 million of revenue.

Q. Did any other witness address this portion of your rebuttal testimony?

A. Yes. Mr. Mierzwa addresses the portion of my testimony discussing Rate IS customers on pages 26 through 27 of his surrebuttal testimony. Mr. Mierzwa states that in my rebuttal testimony I "imply that it is unreasonable to ever propose an increase for Rate IS customers with competitive options." (OCA St. No. 3-SR, p. 27.)

I said nothing of the sort in my rebuttal testimony. In fact, Mr. Mierzwa uses my own exhibit to show that the Company has increased the revenues associated with these customers over time, which is exactly what I said in my testimony.

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

UGI Gas Exhibit CRB-1RJ

Responses of NRG Energy, Inc. to the Interrogatories of UGI Utilities, Inc. – Gas Division, Set I in Docket No. R-2021-3030218

Request: UGI – NRG I-9: Reference NRG Statement No. 1, pages 12-13. Please identify any and all utilities of which NRG is aware that have the automatic process requested by NRG. Please provide any details about the automated programs provided by other utilities.

Response:

An example of a utility that has an automatic notification process is Keyspan New York. Confirmations and cuts are manually made for firm and non-firm nominations, and emails are automatically generated by the system. NRG's emphasis is not on automated programming, which would alleviate the need for human involvement. Rather, NRG is seeking the same level of service that is provided by the utility during the week. The goal is to receive information on a timely basis when NRG has the ability to respond and remedy any issues. Waiting until the next business day (or two business day later, as shown in Attachment 6 provided in response to UGI-NRG-I-6) continues to put NRG at risk of penalty as it is at the discretion of the utility, interstate pipeline and third party wholesale supplier all agreeing to a retroactive nomination change when the issue could have been remedied in real time. NRG desires to ensure compliance with its obligations to UGI and to avoid contributing to any potential operational issues on UGI's system.

Response provided by: Christopher Reyes

Dated: May 2, 2022

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 2-RJ

Rejoinder Testimony of
Tracy A. Hazenstab

Topics Addressed:	**Updates to Case**
	Payroll Expense
	Pennsylvania Act 40

Dated: June 1, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy A. Hazenstab. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 2, on January 28, 2022. I also submitted my rebuttal testimony, UGI Gas Statement No. 2-R, on May 17, 2022.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain portions of the following surrebuttal testimony submitted by the Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"): I&E Statement No. 1-SR, the surrebuttal testimony of Zachari Walker; I&E Statement No. 3-SR, the surrebuttal testimony of Brain J. LaTorre; and OCA Statement No. 1SR, the surrebuttal testimony of Dante Mugrace.

Q. If you do not address specific aspects of the other parties' surrebuttal testimony that responded to your rebuttal testimony, does that mean you agree with the other party?

A. No. Unless otherwise specifically noted in my rejoinder testimony, UGI Gas maintains its rebuttal position in response to each adjustment raised by the other parties.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes. UGI Gas Exhibit A – Fully Projected (REJOINDER).

II. UPDATES TO CASE

Q. Since the filing of your rebuttal testimony, has the Company identified any additional components of its filing that should be updated?

A. Yes. The Company has revised the presentation of the plant in service adjustment on Schedule C-2. In UGI Gas Exhibit A – Fully Projected (REBUTTAL), the net plant in service decrease of $671,000 was included in the ProForma Adjustment Column 4 on Schedule C-2, Page 5, Line 40. In UGI Gas Exhibit A – Fully Projected (REJOINDER), this adjustment was reallocated into the appropriate fiscal years. The year-end plant balance for the year ended September 30, 2022 was reduced by $700,000 and the year-end plant balance for the year ended September 30, 2023 was increased by $29,000, which net to the $671,000 decrease discussed in the rebuttal testimony of Vicky A. Schappell (UGI Gas St. No. 5-R). Additionally, the fiscal year total additions on Schedule C-2, Page 7, Line 40 were adjusted by the same amounts. These updates did not revise the revenue requirement, net plant in service, or total rate base on Schedule A-1, which aligns with the Schedule A-1 included in UGI Gas Exhibit A – Fully Projected (REBUTTAL).

III. PAYROLL EXPENSE – I&E VACANCY RATE

Q. Did any of the other parties address your acceptance of the OCA's recommended adjustment to remove budgeted positions from the Company's claimed headcount to calculate payroll expense?

A. Yes. I&E witness Mr. Walker responds further to this adjustment. I&E St. No. 1-SR at 20-21. While he agrees with the Company's acceptance of OCA's adjustment, Mr. Walker recommended the application of an additional 1.59% vacancy rate, which would reduce the Company's updated payroll expense claim by an additional $1,307,568 on top of the

OCA's $779,000 adjustment that the Company accepted, thereby reducing the Company's payroll expense by a combined $2,086,568. I&E St. No. 1-SR at 21. This would reduce the Company's payroll expense allowance from $82,237,000 to $80,929,432.

Q. Did Mr. Walker respond to your rebuttal testimony regarding how the vacancy rate proposed in his direct testimony was biased due to the impacts of COVID-19 on the Company's ability to hire new employees during Fiscal Year ("FY") 2020?

A. Yes. He accepts my recommendation to remove FY 2020 from the calculation of a vacancy rate, and specifically accepts my "assertion that 2020 did heavily weight the average vacancy rate." I&E St. No. 1-SR at 20. He further recognized that "extraordinary hiring circumstances" evidenced by actual employee count occurred during FY 2020. I&E St. No. 1-SR at 20. As such, he removes the inconsistent data associated with FY 2020 and lowered his proposed vacancy rate. I&E St. No. 1-SR at 21.

Q. Does the Company agree with Mr. Walker's proposed vacancy rate, as revised in his surrebuttal testimony?

A. The Company agrees that Mr. Walker's removal of FY 2020 data from this calculation was warranted due to the extraordinary hiring circumstances imposed by the COVID-19 pandemic. This data was not reflective of a vacancy rate calculated based on normal operating conditions.

However, Mr. Walker's proposal to then have his 1.59% vacancy rate additive to the proposed removal of 17 positions by the OCA (I&E St. No. 1-SR at 20-21) is not reasonable and should be rejected. Mr. Walker's proposal would result in double-counting.

OCA's removal of 17 budgeted positions already addresses a number of positions covered by Mr. Walker's proposed adjustment. The impact of I&E's modified adjustment would essentially remove an additional 27 positions from the Company's budget, for a total of 44 positions. If permitted, I&E's removal of 27 positions *in addition to* OCA's adjustment to remove 17 positions would result in a vacancy adjustment that is actually closer to the originally proposed I&E vacancy adjustment of 2.74% (or 47 positions) rather than an adjustment based on 27 positions. I&E St. No. 1-SR at 20-21. If Mr. Walker's recommendation is adopted, it should be adjusted to account for the 17 positions already removed, and thus reflect only the net of 10 (27 - 17) additional positions. However, the Company continues to believe no further adjustment is required beyond that which the Company has made in rebuttal testimony.

IV. <u>PENNSYLVANIA ACT 40</u>

Q. Does OCA witness Mr. Mugrace continue to assert in his surrebuttal testimony that the Company has not complied with the requirements of Pennsylvania Act 40 ("Act 40") of 2016?

A. Yes, he does.

Q. Do any of the statements by Mr. Mugrace in his surrebuttal testimony warrant further response?

A. While the Company fully responded to all the arguments raised by Mr. Mugrace in his direct testimony, I need to correct a misstatement by Mr. Mugrace in his surrebuttal testimony. He testifies that "While Ms. Hazenstab stated that 50% of the CTA is related to 'rate base eligible' infrastructure and has demonstrated that the Company has utilized these dollars for such, the Company simple omits how the other 50% of the differential is to be used for general corporate purposes." OCA St. No. 1-SR at 34.

Mr. Mugrace seems to ignore my rebuttal testimony. I clearly stated that "50% of the amount calculated in this proceeding will in fact be used for general corporate purposes, as that term is understood." UGI Gas St. No. 2-R at 21. In addition, I provided concrete examples of how the hypothetically calculated 50% of the Consolidated Tax Adjustment ("CTA") amount would be used for the purpose of providing public utility service, despite the difficulty of tracing it to specific projects. UGI Gas St. No. 2-R at 21.

Q. Do you have any response to Mr. Mugrace's assertion that the Commission "does not have to rely on whether any IRS violation exists" in considering his proposal to use 50% of the Act 40 calculation to offset the Company's claims in this case?

A. Yes. To the extent that Mr. Mugrace is suggesting that the Commission would accept a ratemaking adjustment that could result in a violation of IRS tax normalization requirements, this suggestion fails to acknowledge the materiality of the IRS normalization requirements and the serious cash consequences to the Company and ratepayers if those violations were lost as explained in my rebuttal (UGI Gas St. No. 2-R at 25). Mr. Mugrace's position is unreasonable and should be rejected.

V. <u>CONCLUSION</u>

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 3-RJ

Rejoinder Testimony of
Vivian K. Ressler

Topics Addressed: **Operating Expense Adjustments**

Dated: June 1, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vivian K. Ressler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 3, on January 28, 2022. I also submitted my rebuttal testimony, UGI Gas Statement No. 3-R, on May 17, 2022.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony briefly responds to certain portions of the following surrebuttal testimony submitted by the Bureau of Investigation and Enforcement ("I&E") and the Office of Consumer Advocate ("OCA"): I&E Statement No. 1-SR, the surrebuttal testimony of Zachari Walker; OCA Statement No. 1SR, the surrebuttal testimony of Dante Mugrace; and OCA Statement No. 3SR, the surrebuttal testimony of Jerome D. Mierzwa.

More specifically, my rejoinder addresses I&E witness Mr. Walker's surrebuttal testimony regarding the Company's proposal to continue to defer incremental COVID-19 uncollectibles expense, and also to recover increased uncollectibles due to rising inflation rates. In addition, I respond to OCA witness Mr. Mugrace's surrebuttal testimony regarding (a) the Company's claim to recover incentive compensation expense, and (b) the OCA's proposed adjustment pension expense. Finally, I respond to OCA witness Mr. Mierzwa's surrebuttal testimony regarding manufactured gas plant remediation expense.

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Q. If you do not address specific aspects of the other parties' surrebuttal testimony that responded to your rebuttal testimony, does that mean you agree with the other party?

A. No. Unless otherwise specifically noted in my rejoinder testimony, UGI Gas maintains its rebuttal position in response to each adjustment raised by the other parties.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes, I am sponsoring UGI Gas Exhibit VKR-1RJ.

II. UNCOLLECTIBLES ACCOUNTS EXPENSE

Q. Do any of the other parties' surrebuttal testimony address the Company's proposal to continue to defer COVID-19 related incremental uncollectibles expense?

A. Yes. I&E witness Mr. Walker continues to dispute the Company's proposal. He claims that "[i]n the current COVID-19 climate higher uncollectible accounts expense is the new normal and will be so for an undetermined amount of time moving forward." I&E St. No. 1-SR at 9. Mr. Walker further claims that in future base rate cases, the routine uncollectible percentage will be developed based on an average of three years of historic data, which will ensure higher amounts will be recovered. I&E St. No. 1-SR at 9. Mr. Walker also continues to rely upon the language of the 2020 Gas Base Rate Case Settlement to assert the settlement does not allow for continued deferral. I&E St. No. 1-SR at 10.

Q. Does Mr. Walker also address the Company's further regulatory asset treatment to uncollectible accounts expense due to an increase in the commodity cost of gas driven by current inflationary factors?

A. Yes. Mr. Walker also opposes this proposal. I&E St. No. 1-SR at 10. He argues there is no basis to allow the Company to accrue increases in uncollectible accounts expense due to inflationary factors. I&E St. No. 1-SR at 10. He also asserts that these increases in costs due to inflation are "transient changes," i.e., that they will only last for a short period of time. I&E St. No. 1-SR at 10.

Q. Does the Company agree with Mr. Walker?

A. No. The Company has fully justified its proposals, as explained in my rebuttal testimony. In addition, the Company has detailed the significant increases in inflation that are currently being experienced. In his rejoinder testimony (UGI Gas Statement No. 6-RJ), Mr. Moul explains that inflation reached a 40-year high of 6.6% in March 2020. This high was exceeded in March of 2022, when the rate reached 8.5%. UGI Gas St. No. 6-R at 6. However, there are two specific points raised by Mr. Walker that warrant further response.

Q. What are those two points?

A. First, Mr. Walker's surrebuttal testimony regarding the COVID-19 pandemic is contradictory. Second, Mr. Walker's continued reliance upon the 2020 Gas Base Rate Case Settlement as precedent is inconsistent with practice before the Commission.

Q. Please respond to Mr. Walker's assertion that in the current COVID-19 climate higher uncollectible costs is "the new normal." I&E St. No. 1-SR at 9.

A. Mr. Walker contradicts himself regarding the impacts of the COVID-19 pandemic. On the one hand, to attempt to reject the Company's proposal to continue to defer incremental

COVID-19 uncollectibles expense, Mr. Walker asserts that increased uncollectibles costs are the new normal. On the other hand, however, Mr. Walker calls increases in inflationary factors due to the COVID-19 pandemic "transient." The impacts of the COVID-19 pandemic on this expense cannot both be "the new normal" and "transient." Mr. Walker's attempt to have it both ways should be rejected.

Q. Please respond to Mr. Walker's continued reliance on the 2020 Gas Base Rate Case Settlement.

A. In addition to the fact that he incorrectly reads the language of the settlement, as described in my rebuttal testimony (UGI Gas St. No. 3-R at 58), Mr. Walker ignores the fact that the settlement specifically acknowledges that it reflects a compromise of competing positions, and that the terms and conditions of the settlement were (a) limited to the facts of the specific case and (b) the product of compromise for the sole purpose of settling the case.

Essentially, Mr. Walker references the prior settlement as if it were binding precedent despite clear language to the contrary. This is inconsistent with practice before the Commission and should be given no weight.

Q. Does Mr. Walker take a position regarding the proposed amortization period that should be used if the Commission decides to allow continued deferral of COVID-19 related uncollectibles expense?

A. Yes. Mr. Walker opposes the Company's proposed 3-year amortization period. I&E St. No. 1-SR at 11. While he agrees with the Company's proposal that amortization should occur without interest, he argues that the actual recovery period should not be assigned until the actual amount is known and verifiable. I&E St. No. 1-SR at 11.

Q. Does the Company agree with Mr. Walker's argument that the Commission should wait to assign an amortization period until the actual amount of incremental uncollectibles expense is known and verifiable?

A. If the Company is authorized to continue to defer any annual uncollectible accounts expense in excess of $18.0 million (or such amount that is built into its rate as approved by the Commission as part of this proceeding) per year and to recover any excess without interest, as proposed in my rebuttal testimony (UGI Gas St. No. 3-R at 59-60), the Company would be willing to wait until its next base rate proceeding to assign an amortization period for recovery.

III. <u>INCENTIVE COMPENSATION</u>

Q. Do any of the other parties' surrebuttal testimony continue to oppose the Company's claimed incentive compensation expense?

A. Yes. OCA witness Mr. Mugrace continues to oppose the Company's claim for recovery of incentive compensation expenses. OCA St. No. 1SR at 1-16. Mr. Mugrace raises a variety of arguments in response to my rebuttal testimony, none of which have any merit.

Q. Does Mr. Mugrace, at any point, address the fact that the Company's incentive compensation is a component of its overall compensation program to attract and retain qualified employees?

A. No, he does not. In fact, Mr. Mugrace fails to acknowledge that his continued attempts to evaluate individual aspects of the Company's incentive compensation program in isolation run afoul of prior Commission orders, *i.e.*, the *PPL Electric 2012 Order*[1] and the *UGI Electric 2018 Order*.[2] As explained in my rebuttal testimony, those orders made clear that incentive compensation programs must be evaluated "as a whole," when determining whether the plan includes goals which benefit customers. UGI Gas St. No. 3-R at 28

Q. Is the incentive compensation program at issue in this proceeding the same as the incentive compensation program that was approved in the *UGI Electric 2018 Order*?

A. Yes. While certain details of the programs have changed since 2018, the substance of the programs has not materially changed. See the table below for a comparison of the programs included in the current case and in the UGI Electric 2018 case.

Plan	Approved for Recovery in 2018 Electric Case	Included in the 2022 Gas Case Claim
Management Incentive Plan	Yes	Yes
Executive Bonus Plan	Yes	Yes
Restricted Stock Awards	Yes	Yes
Stock Options	Yes	Yes

Q. Has the Commission recently re-affirmed the analysis of incentive compensation programs from the *PPL Electric 2012 Order* and the *UGI Electric 2018 Order*?

[1] *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2012-2290597, at p. 26 (Final Order entered December 28, 2012).

[2] *Pa. PUC, et al. v. UGI Utilities, Inc. – Electric Division*, Docket No. R-2017-2640058, at p. 73-74 (Order entered Oct. 25, 2018).

A. Yes. In a decision in the recent *Aqua 2021 Order,*[3] the Commission once again affirmed that a utility is permitted to recover the costs of its incentive compensation program, including stock based compensation, when the program is linked with benefits to customers and improved operational efficiency. Moreover, the Commission agreed with the Administrative Law Judge in the Aqua case, who noted in the Recommended Decision that incentive compensation is a key element of overall payment packages to attract and keep a skilled workforce.[4]

As explained in my rebuttal testimony (UGI Gas St. No. 3-R at 22-35) UGI Gas's incentive compensation program, as a whole, is linked to performance and operational objectives, including safety, cost control and the satisfaction of compliance initiatives. Moreover, it is an essential part of attracting and retaining qualified employees to provide safe and reliable natural gas service to the Company's customers.

Q. Are there any further new arguments raised by Mr. Mugrace in his surrebuttal testimony regarding the Company's claimed incentive compensation expense that you wish to address?

A. Yes, there are two new arguments that Mr. Mugrace attempts to raise in his surrebuttal testimony that warrant further response. First, Mr. Mugrace's acknowledges that the Company's incentive compensation does include safety and reliability, customer service and customer satisfaction goals (OCA St. No. 1SR at 13), but continues to oppose recovery on the basis that no specific dollar amounts for these goals were provided. Second, Mr.

[3] *Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. v. Pa PUC, et al.*, Docket Nos. R-2021-3027385 and R-2021-3027386, et al. (Opinion and Order entered May 16, 2022).
[4] *Aqua 2021 Order*, pp. 100-101.

Mugrace incorrectly suggests that the Company's claimed expense was based upon information he was not provided during discovery or as a part of my rebuttal testimony.

Q. Please respond to Mr. Mugrace's specific claim that recovery of the Company's incentive compensation programs should not be allowed because he was unable to evaluate dollar amounts associated with safety and reliability, customer service and customer satisfaction performance goals. OCA St. No. 1SR at 13.

A. This argument is nothing more than an even narrower version of the argument previously rejected in the various Commission orders I cited above. Now, instead of trying to target specific plans that are part of the Company's overall incentive compensation program, Mr. Mugrace is attempting to target specific dollar amounts within specific plans. This logic should not be credited. This argument simply embodies his failure to support the need for more granularity in the review of these claims than the arguments previously rejected by the Commission in the *PPL Electric 2012 Order*, the *UGI Electric 2018 Order*, and the *Aqua 2021 Order*. Therefore, it should be rejected for the same reasons I described above and in my rebuttal testimony. UGI Gas St. No. 3-R at 21-37.

Q. Please respond to Mr. Mugrace's claims that he was not provided one of the exhibits attached to your rebuttal testimony.

A. Mr. Mugrace's claim that UGI Gas Exhibit VKR-7R was not attached to my rebuttal testimony is incorrect. OCA St. No. 1SR at 9-10. This exhibit was a public exhibit only (although Mr. Mugrace seems to incorrectly believe it was confidential) that was included in the PDF packet for the public version of my rebuttal testimony. Although OCA served an errata to Mr. Mugrace's surrebuttal testimony on June 1, 2022, that removed one reference to this assertion from page 11, the errata does not remove the other incorrect references on pages 9-10.

Q. Mr. Mugrace also claims that the information the Company used to support its UGI Corporate Allocation is "new information which was not provided in discovery." OCA St. No. 1SR at 9-10, 13. Do you agree with this statement?

A. Again, unfortunately, Mr. Mugrace is simply incorrect. Mr. Mugrace references the Company's response to OCA-III-1 and OCA-VII-13. The Company's responses to each of these discovery requests are being provided as UGI Gas Exhibit VKR-1RJ; however, the attachments to these discovery responses will be omitted obviate the need for HIGHLY CONFIDENTIAL designations.

Q. What does Mr. Mugrace claim with respect to the OCA-III-1 discovery request and response?

A. With respect to OCA-III-1, he claims that he "asked for information related to Incentive Bonuses and confidential information." OCA St. No. 1SR at 9.

Q. What does OCA-III-1 request?

A. It asks that the Company "[p]lease provide all confidential documents and related exhibits referenced in the filing related to Compensation Benchmarking and Incentive Bonuses." UGI Gas Exhibit VKR-1RJ, page 1.

Q. Why is the specific language of this request important?

A. As a part of this case, the Company included a salary & wage increase claim based upon various compensation benchmark analyses. This increase was explained in the direct testimony of UGI Gas witness Mr. Christopher R. Brown. UGI Gas St. No. 1 at 26-29.

Importantly, Mr. Mugrace testified regarding these adjustments in his direct testimony. Indeed, he specifically addressed Mr. Brown's direct testimony regarding the development of the proposed salary and wage adjustments <u>and makes reference to</u> the documents provided in response to OCA-III-1 (e.g., data provided by the American Gas Association). OCA St. No. 1 at 17-18. It is not reasonable for Mr. Mugrace to assert, as he does, that this request was related to an aspect of the Company's claim other than certain proposed salary and wage adjustments.

Q. What does Mr. Mugrace claim with respect to the OCA-VII-13 discovery request and response?

A. Mr. Mugrace claims that this request "asked for information related to incentive compensation." OCA St. No. 1SR at 9.

Q. What does OCA-VII-13 actually request?

A. It asks "Has the Company included any Stock Compensation expenses in its development of the revenue requirement increase? If so, please identify and show where these costs are recorded and accounted for." UGI Gas Exhibit VKR-1RJ, page 2. In response to this request, the Company provided a breakdown of the costs included, and identified where in the initial filing all stock compensation expenses were recorded in the revenue requirement.

Q. Why is this distinction important?

A. If Mr. Mugrace wanted to review specific documents related to other aspects of the Company's claim for incentive compensation expense, he could have, and should have, asked for them. Again, it is not reasonable for Mr. Mugrace to assert, as he does, that he was not provided certain information in discovery despite the fact that he simply did not ask for it.

Furthermore, if Mr. Mugrace was dissatisfied with information provided to him, he could have asked follow-up questions in discovery for additional information. It appears that Mr. Mugrace had ample opportunity to ask follow-up questions, but simply did not do so; the response to OCA-III-1 was served on March 25, 2022 and the response to OCA-VII-13 was served on March 28, 2022, whereas the OCA's direct testimony was not served until April 20, 2022.

IV. PENSION EXPENSE

Q. Does OCA witness Mr. Mugrace continue to propose an adjustment to the Company's pension benefits expense?

A. Yes. Mr. Mugrace continues to propose the same pension adjustment in his rebuttal testimony (OCA St. No. 1SR, Schedule SR-DM-17, Line 18) that he proposed in his direct testimony (OCA St. No. 1, Schedule DM-17, Line 18).

Q. Does the Company agree with Mr. Mugrace's proposed adjustment for pension?

A. No.

Q. Why does the Company not agree with Mr. Mugrace's proposed adjustment for pension?

A. The Company does not agree with Mr. Mugrace's adjustment for several reasons. Most importantly, Mr. Mugrace does not base his adjustment on pension cash contributions, which are the basis for the Company's claim (as explained in my rebuttal testimony) UGI Gas St. No. 3R at 16. Secondly, the Company does not believe that it is appropriate to normalize its claim amount.

Q. On what did Mr. Mugrace base his proposed adjustment?

A. As explained in my rebuttal testimony (UGI Gas St. No. 3R at 16-17), Mr. Mugrace based his adjustment on the difference between generally accepted accounting principles ("GAAP") pension expense and pension cash contributions.

Q. Why is it important that the Company bases its claim on cash contributions?

A. The Commission has approved recovery of pension cost based on cash contributions within UGI Gas's rate proceedings and within the rate proceedings of most other utilities within Pennsylvania for many years.[5] Moreover, if the Company were to "mix and match" its method of recovering its pension cost between GAAP pension expense and cash

[5] *See, e.g.*, *Pa. PUC, et al. v. Metropolitan Edison Company*, Docket No. R-00922314, et al., 1993 Pa. PUC LEXIS 41, at *81-82 (Opinion and Order dated Jan. 21, 1993) ("The OTS correctly noted that pension expense should be treated on a cash only basis. Therefore, the FASB 87 calculation is rejected."); *Pa. PUC, et al v. West Penn Power Company*, Docket Nos. R-0901609, et al., 1990 Pa. PUC LEXIS 142, at *95-96 (Opinion and Order dated Dec. 13, 1990) ("We agree with the OTS that pension expense should be treated on a "cash only" basis. As pointed out in the OTS filings on this issue, WPP's pension is currently overfunded, and IRS regulations will allow no tax deductible contributions for 1990. It is the contributions that WPP will actually make to the pension fund during the test year…which is the relevant amount in considering the allowable expense for ratemaking purposes."); *Pa. PUC v. Phila. Suburban Water Co.*, Docket No. R-891270, 1989 Pa. PUC LEXIS 213, at *54-61 (Opinion and Order dated Dec. 29, 1989).

contributions, the Company would not recover an appropriate amount of costs over the life of the plan.

Q. What issues did Mr. Mugrace raise in his surrebuttal testimony related to the Company's pension claim?

A. Mr. Mugrace takes issue with the Company's claim to recover pension costs based upon its actual cash contributions to the pension fund. OCA St. No. 1SR at 27-28. He claims that the Company has not provided information explaining the variability of recorded pension expense (for GAAP purposes) or the variability of the Company's cash contributions to the fund. OCA St. No. 1SR at 28. Although he acknowledges that the Company based its cash contributions upon the recommendations of its actuarial firm, and that the Company's claim is consistent with GAAP and historical ratemaking practice, he asserts that it is necessary to average out contributions made in prior years to contributions made during current years because "solely relying on current actually-determined cash contributions to the pension fund can result in costs that may be too high *or* too low for the new regulatory period when new rates are set." OCA St. No. 1SR at 28.

Q. Please explain why GAAP pension expense and cash contributions vary from year to year.

A. Pension expense under GAAP is calculated annually based on a complex actuarial valuation that includes forward looking estimates (such as discount rate and return on assets) which depend on point in time market conditions.

The Company's cash contributions are calculated annually by its actuary in accordance with the Company's pension funding policy. The cash contributions are designed to approximate the cost of expected benefits only and are more stable than GAAP expense because certain market-based assumptions are excluded from the calculation and other market based assumptions (such as the discount rate) are based on 24 month averages.

Q. Why does the Company believe that it should include the most current cash contribution amount in its claim, rather than a normalized amount as proposed by Mr. Mugrace?

A. The Company believes that it is more appropriate to use the most current actuarially-determined cash contribution amount within its claim, rather than a normalized amount, because it reflects the most up-to-date estimate of expected pension cost. The Commission has repeatedly approved this approach, as noted above.

However, as indicated in my rebuttal testimony (UGI Gas St. No. 3R at 15-16), if the Company were to normalize its actual cash contributions, it would increase the Company's claim from $5.501 million to $5.765 million. The Company has not normalized its recovered costs associated with the pension plan in the past, and believes consistency is appropriate, as this would avoid the issues with "mixing and matching" what costs are recovered through rates that I discussed above.

V. MANUFACTURED GAS PLANT REMEDIATION EXPENSE

Q. Do any of the other parties' raise new issues with respect to the recoverability of the Company's claimed environmental remediation expense associated with manufactured gas plants ("MGPs")?

A. Yes. OCA witness Mr. Mierzwa raises the new argument that "[i]t would be more appropriate to deny UGI Gas recovery of these costs since MGPs are not currently used and useful in the provision of utility service" as a part of his surrebuttal testimony responding to the rebuttal testimony of UGI Gas witness Ms. Heppenstall. OCA St. No. 3SR at 6.

Q. Does the Company agree with Mr. Mierzwa's new argument?

A. No, for three reasons. First, as I previously noted, this is a disallowance proposal raised by Mr. Mierzwa (and the OCA) for the first time in their surrebuttal testimony. More importantly, however, this position directly contradicts the recommendations of OCA witness Mr. Mugrace with respect to the Company's proposal to recover the environmental remediation costs associated with MGP sites. Mr. Mugrace clearly testified that he was "accepting the Company's five years of actual and projected spending" for these costs, but made an alternative recommendation regarding the appropriate period for recovery. OCA No. St. 1 at 15-16. If the OCA was going to propose total disallowance of these costs, they should have done and could have done so in their direct testimony.

Second, the Company has recovered the costs of MGP remediation in all litigated and settled rate cases since the mid-1990s through the costs of removal, or, more recently, through a balancing mechanism that addresses any over- or under-recovery of such remediation costs. I discussed this mechanism in my rebuttal testimony (UGI Gas St. No. 3-R at 11). While the Company recognizes that the MGPs were retired years ago, the costs at issue are properly recovered in accordance with the Uniform System of Accounts as costs incurred in connection with sites that were used to provide safe, efficient and reliable public utility service.

Third, even if it were appropriate for Mr. Mierzwa to raise this argument for the first time in his surrebuttal testimony (and it is not), his claim that MGP sites are no longer used and useful is not completely accurate. The Company utilizes several MGP sites as office space and for purposes of storing materials. For example, eight operations centers are on former MGP sites (Shamokin, Bloomsburg, Renovo, Lancaster, Clearfield, Oxford, Hazleton, and Lebanon), eight additional former MGP sites are used for equipment and/or materials storage (Ashland, Lehighton, Allentown, Reading, Steelton, Bethlehem, Edwardsville, and Huntingdon), and two former MGP sites are used for regulator stations (Manheim and Boyertown).

VI. <u>CONCLUSION</u>

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

UGI Gas Exhibit VKR-1RJ

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to OCA Set III (1 thru 34)
Delivered on March 9, 2022

OCA-III-1

Request:

Please provide all confidential documents and related exhibits referenced in the filing related to Compensation Benchmarking and Incentive Bonuses.

Response:

Please see HIGHLY CONFIDENTIAL PROTECTED MATERIALS Attachment OCA-III-1A for the AGA Compensation Survey Report, HIGHLY CONFIDENTIAL PROTECTED MATERIALS Attachment OCA-III-1B for the UGI Benchmark Analysis, and HIGHLY CONFIDENTIAL PROTECTED MATERIALS Attachment OCA-III-1C for the UGI Compensation Adjustment Detail.

[redacted]

Prepared by or under the supervision of: Christopher R. Brown

[redacted]

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to OCA Set VII (1 thru 13)
Delivered on March 28, 2022

OCA-VII-13

Request:

Has the Company included any Stock Compensation expenses in its development of the revenue requirement increase? If so, please identify and show where these costs are recorded and accounted for.

Response:

For a breakdown of the stock compensation within the revenue requirement please reference Attachment I&E-RE-17.2.

All stock compensation expenses recorded in the revenue requirement can be found in Book V, Exhibit A, Schedule B-4 within FERC 920.0 Administrative and General Salaries.

Prepared by or under the supervision of: Vivian K. Ressler

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 5-RJ

Rejoinder Testimony of
Vicky A. Schappell

Topics Addressed: Utility Plant In Service

Dated: June 1, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Vicky A. Schappell. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 5, on January 28, 2022. I also submitted my rebuttal testimony, UGI Gas Statement No. 5-R, on May 17, 2022.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain portions of the surrebuttal testimony submitted by the Bureau of Investigation and Enforcement ("I&E") witness Esyan Sakaya, I&E Statement No. 5-SR.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes, I am sponsoring UGI Gas Exhibit VAS-1RJ.

II. UTILITY PLANT IN SERVICE

Q. Does Mr. Sakaya modify his methodology in response to your rebuttal testimony?

A. No, he does not. Despite the numerous methodological errors undermining the credibility of his recommendation that I identified in my rebuttal testimony, Mr. Sakaya does not make any corrections. Described simply, Mr. Sakaya's methodology is incorrect at every step of his process, and as a result his disallowance is neither reasonable nor logical.

Q. Mr. Sakaya states that his analysis is a "variance analysis" and suggests that therefore his methodology is grounded in accounting principles. Do you have any response to this?

A. Yes. A variance analysis is an accounting methodology that compares predicted and actual outcomes. Mr. Sakaya states that variance in accounting is the difference between a forecasted amount and the actual amount (Forecast – Actual = Variance). However, Mr. Sakaya did not perform a true variance analysis, because he mixes and matches the amounts used in his calculations.

In essence, Mr. Sakaya calculates the variance between the projected total plant in service balance (i.e., the wrong starting point) and subtracts the actual plant in service balance to calculate a gas plant shortfall. But, Mr. Sakaya then mixes different amounts together, and subtracts this gas plant shortfall from estimated gas plant additions, before calculating his variance percentage or installation success rate. Each step of this calculation is explained in my rebuttal testimony (UGI Gas Statement No. 5-R at 14-15) and further shown in UGI Gas Exhibit VKR-4R (*see* "Walk-Through of Mr. Sakaya's Calculation"). This method used by Mr. Sakaya is not the appropriate way to calculate a variance percentage.

While I believe the Commission should reject Mr. Sakaya's method and use of a variance analysis for the reasons stated above and in my rebuttal testimony, to correctly conduct a variance analysis one should simply divide actual plant additions (i.e., what plant was added) by budgeted plant additions (i.e., what plant was forecasted to be added). Then, one would multiply the total by 100 to turn it into a percentage (Actual / Forecast) x 100.

This is the method used by the Company in the "Corrected Walk-Through of Mr. Sakaya's Calculation" in UGI Gas Exhibit VAS-4R lines 13-15 to calculate an installation success rate or variance percentage. These corrections further demonstrate that Mr. Sakaya's method is unreliable and that the appropriate comparison is budgeted vs. actual plant additions, as submitted by the Company.

Q. Is Mr. Sakaya's methodology otherwise unreliable?

A. Yes. It contains two other fatal flaws that make it unreliable. His success rate for Gas Plant is limited to a two year analysis – the FPFTY data from the 2019 Gas Base Rate Case (i.e., FY 2020) and the 2020 Gas Base Rate Case (i.e., FY 2021). The use of only two years of data is too short to provide a reliable average variance.

Second, and perhaps more critically, Mr. Sakaya's only two data points are outliers. The 2019 Gas Base Rate Case FPFTY includes data from October 1, 2019 through September 30, 2020, with COVID-19 causing significant impacts for nearly half of that test year. The 2020 Gas Base Rate Case FPFTY includes data from October 1, 2020 through September 30, 2021, during which time the Company's operations were returning to normal since the inception of the COVID-19 pandemic. Mr. Sakaya's methodology relies exclusively on two years of anomalous data.

On the other hand, the Company has demonstrated that over a 3- or 5-year period of time, it has a documented history of meeting its budgeted capital project additions. Specifically, over a 3-year period that excludes anomalous data caused by the COVID-19 pandemic, the Company placed an average of 102.3% of its budgeted plant additions into service (UGI Gas Exhibit VAS-2R); over a 5-year period that accounts for both normal operating conditions and the years impacted by the COVID-19 pandemic, the Company placed an average of 98.0% of budgeted plant additions into service.

Q. On page 14 of his testimony, Mr. Sakaya claims that it is proper to adjust for retirements because "if plant is not placed into service, retirements will not occur." Is this accurate?

A. No, it is not accurate. UGI Gas regularly has retirement projects that do not have additions associated with them and Mr. Sakaya's claim incorrectly links these separate Company activities without any evidence, or knowledge of the Company's operations. It is important to note that these are separate activities and, therefore, should receive separate rate treatment. Moreover, Plant additions should not be lowered to reflect retirements, because retirements are already reflected in rates through a separate downward plant adjustment and related accumulated depreciation and negative salvage adjustments. Mr. Sakaya's methodology thus double counts the Company's retirements. Even if the Commission were to ignore all of the other flaws in his methodology, this flaw alone incorrectly results in his methodology overstating the disallowance by $131.3 million (*see* UGI Gas Statement No. 5-R at 19 and UGI Gas Exhibit VAS-4R, line 20) or approximately 85% of his adjustment.

Q. What other flaws are produced by Mr. Sakaya's use of test years rather than budgets?

A. Another reason Mr. Sakaya's insistence on the use of test years is not appropriate is because utilities may not have annual rate cases. However, Mr. Sakaya's methodology only looks at test years, which would require annual base rate cases to occur. Mr. Sakaya's methodology would result in the rejection of the most recent data in favor of stale data that may not result in an accurate forecast of the Company's operations.

Q. Mr. Sakaya states that the Commission should use the FPFTY projections from past cases because the amounts cannot be changed. Is this accurate?

A. No, it is not. It is not even accurate within the case itself, and it is another example of an error in Mr. Sakaya's methodology. Mr. Sakaya refuses to adjust his calculations for the known adjustments made in the Company's rebuttal testimony in the two proceedings he relies on. I&E St. No. 5-SR at 13. Yet, Mr. Sakaya accepted my updates on plant additions as part of this case.

More importantly, the Company must make adjustments to its project lists on an annual basis based on operational needs. As explained in my rebuttal testimony, the Company's history of placing 98% of budgeted plant additions into service takes into account the movement of projects from one year to the next and the impact of bringing future year projects into an earlier year. UGI Gas St. No. 5-R at 21-22. As an additional example, the Company's Distribution Integrity Management Plan ("DIMP") requires that UGI Gas evaluate its project lists and update them on at least an annual basis to ensure that the Company is addressing the riskiest assets on its system. Mr. Sakaya proposes that the Commission use a process for ratemaking that fails to acknowledge the dynamic process the Company uses for operating its system.

Q. Mr. Sakaya discusses the implications of a black box settlement on pages 15 and 16 of his testimony. Do you have any response?

A. Yes, I do. First, I am advised by counsel that Mr. Sakaya's insistence on using settled case outcomes for precedential value is improper. However, to the extent that the Commission decides to consider Mr. Sakaya's comments on the use of the DSIC trigger point that has been articulated in the Company's settlements, Mr. Sakaya is, again, entirely incorrect in his claims. The DSIC-eligible plant threshold included in the Commission-approved settlement for the 2019 Gas Base Rate Case was based on the net total plant balances projected for the FPFTY used in that case (i.e., FY 2020), in the amount of $2,875,056,000.[1] However, Mr. Sakaya fails to recognize that DSIC-eligible plant threshold included in the Commission-approved settlement for the 2020 Gas Base Rate Case was based on the net total plant balances projected for the **FTY** used in that case (i.e., FY 2020), in the amount of $2,875,056,000.[2] If one compares the projected total net plant balances included in each of the last two UGI Gas base rate case settlements to the actual plant additions made during the applicable period of FY 2020—as Mr. Sakaya suggested would reinforce his position—it would actually produce a completed plant additions number of 102.7%, as shown in UGI Gas Exhibit VAS-1RJ. This further demonstrates the flaws in Mr. Sakaya's methodology.

Q. Please respond to Mr. Sakaya's surrebuttal testimony on inflation.

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[1] *Pa. PUC, et al. v. UGI Utilities, Inc. – Gas Division,* Docket No. R-2018-3006814, et al., at p. 7 (Opinion and Order entered Oct. 4, 2019).

[2] *Pa. PUC, et al. v. UGI Utilities, Inc. – Gas Division,* Docket No. R-2019-3015162, et al., at Ordering Paragraph 27 (Opinion and Order entered Oct. 8, 2020); *see also Pa. PUC, et al. v. UGI Utilities, Inc. – Gas Division,* Docket No. R-2019-3015162, et al., at p. 26 (Recommended Decision dated Aug. 29, 2020) ("As of the effective date of rates in this proceeding, UGI Gas will continue to be eligible to include plant additions in the Distribution System Improvement Charge ('DSIC') once the Company's total net plant balances reach a level of $2,875,056,000; as established in the UGI Gas 2019 Base Rate Case.")

A. Mr. Sakaya appears to have misunderstood the nature of my rebuttal testimony comments on inflation. However, his testimony supports my point. My rebuttal testimony indicated that the impact of the increased contractor costs discussed by UGI Gas witness Mr. Angstadt (UGI Gas St. No. 9-R) will make it even more likely that the Company will meet or exceed its plant addition budget in the FPFTY when compared to past years, because the Company's as-filed FPFTY had not factored in the significant impacts of inflation on its plant additions. My rebuttal testimony did not update the FPFTY for the new contractor costs, and I instead argued that the fact that the Company will incur these higher contractor costs should be taken as further evidence that Mr. Sakaya's disallowance is incorrect as calculated in his direct testimony. *See* UGI Gas St. No. 5-R at 10-13.

Q. Mr. Sakaya states that if inflation was a factor in past cases, "it would have caused the Company to exceed its rate case projection…" (I&E St. No. 5-SR, p. 12.) What is your response?

A. I fully agree with Mr. Sakaya's point here. However, as Mr. Angstadt states in his rebuttal testimony, the impact of inflation on the Company construction contracts was low because contractor pricing was fixed during the period of 2019-2021 and inflationary pressures were low during the same time. Moreover, Mr. Sakaya fails to consider the impact of increased contract costs on the FPFTY plant additions in his calculation, even after I specifically identified the known contractor pricing increases for the FPFTY.

III. <u>CONCLUSION</u>

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

UGI Gas Exhibit VAS-1RJ

UGI UTILITIES, INC. - GAS DIVISION
Comparison of 2019 and 2020 Base Rate Cases DSIC Settlement

	2019 Gas Base Rate Case Net Plant in Service as of September 30, 2020			2020 Gas Base Rate Case Net Plant in Service as of September 30, 2021			2-Year Total Net Plant in Service		
	DSIC Settlement Amount	Actual	Actual vs. Settlement	DSIC Settlement Amount	Actual	Actual vs. Settlement	DSIC Settlement Amount	Actual	Actual vs. Settlement
Net Plant in Service	$ 2,875,056	$ 2,821,055	$ (54,001)	$ 2,875,056	$ 3,082,477	$ 207,421	$ 5,750,112	$ 5,903,532	$ 153,420
	(1)	(2)		(1)	(2)		(1)	(2)	
Actuals as % of Rate Base Claims	(2) / (1)	**98.1%**		(2) / (1)	**107.2%**		(2) / (1)	**102.7%**	
		(A)			(A)			(A)	

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 6 - RJ

Rejoinder Testimony of
Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Topics Addressed:	**Cost of Capital** **Capital Structure** **Rate of Return**

Dated: June 1, 2022

REJOINDER TESTIMONY OF PAUL R. MOUL

Q. Please state your name, occupation and business address.

A. My name is Paul R. Moul and I am Managing Consultant at the firm P. Moul & Associates. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062.

Q. Mr. Moul, have you previously submitted direct and rebuttal testimony in this proceeding?

A. Yes. My direct testimony, UGI Gas Statement No. 6, was submitted with the Company's case-in-chief on January 28, 2022 and my rebuttal testimony, UGI Gas Statement No. 6-R, was submitted on May 17, 2022.

Q. What is the purpose of your rejoinder testimony?

A. UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") has requested that I respond to the surrebuttal testimony presented by Mr. Anthony Spadaccio, a witness appearing on behalf of the Bureau of Investigation and Enforcement ("I&E"), and Mr. David J. Garrett, a witness appearing on behalf of the Office of Consumer Advocate ("OCA"). If I fail to address each and every issue in the surrebuttal testimony of Mr. Garrett and Mr. Spadaccio, it does not imply agreement with those issues.

Q. Based on your review of the surrebuttal testimony of Mr. Spadaccio and Mr. Garrett, do you propose any change in your recommended return for UGI Gas in this proceeding?

A. No. There was nothing contained in the surrebuttal testimony of Messrs. Spadaccio and Garrett that changes my position that UGI Gas is entitled to an 11.20% rate of return on common equity. The proposals of Messrs. Spadaccio and Garrett of 9.92% and 8.50%, respectively, are entirely too low by reference to returns set by the Commission in recent rate cases and Distribution Service Improvement Charge

("DSIC") proceedings that I describe in my rebuttal testimony. Mr. Spadaccio's argument that the DSIC rate is merely a benchmark to identify "overearning" and that it provides an incentive for investment in infrastructure replacement and betterment is misplaced. The actual collection of revenues from the DSIC can only occur if earnings are below the DSIC rate. And it makes no sense that once DSIC assets enter the rate base that they should earn a lower return when they enter rate base, which seems to be Mr. Spadaccio's position because his 9.92% equity return is well below the current 10.20% DSIC rate for gas utilities. Although the Commission has stated that the DSIC return is not company specific and is determined on a quarterly basis (see page 178 of Aqua Order Entered May 16, 2022 in Docket No. R-2021-3027385), it does provide an overall benchmark to gauge the reasonableness of the proposed return. Moreover, referencing the DSIC return when setting the cost of equity in a base rate case would not promote an over-earnings status that would preclude its use (see page 13 of Mr. Spadaccio's Surrebuttal testimony). This situation is unlikely because base rates are adjusted periodically through the rate case process that provides only an opportunity to experience a fair return. Between rate cases, investment and expense change and there is no true up available to reconcile for those variations. This would occur with or without a DSIC return.

Q. At pages 9-10 of his surrebuttal testimony, Mr. Spadaccio discusses the relative weight that should be assigned to the DCF. Please respond.

A. His discussion as to the weight that should be given DCF is somewhat difficult to follow. As near as I can tell, he proposes that the CAPM should only be used as a comparison to DCF, but not as additional input. As I understand it, Mr. Spadaccio is essentially arguing for exclusive weight to DCF. This position is contrary to the

Commission's recent Aqua Order Entered May 16, 2022 in Docket No. R-2021-3027385), in which the Commission determined that it is appropriate to use the DCF and CAPM methodologies in a rising interest rate market. While Mr. Spadaccio seems troubled by alternative models, including CAPM, there are many assumptions associated with the specification of the DCF. These are:

- The form of the model. A choice must be made whether to employ the continuous or discrete form of the model.
- Whether a finite or infinite form of the model realistically represents investor's horizon.
- Whether compounding of the quarterly dividend should be employed.
- The timing of the dividend payments regarding the interval from the ex-dividend date and the stock measurement date needs to be addressed.
- A choice is necessary relative to a representative price that would reasonably represent the rate effective period, e.g., 12-month average, 6-month average, 13-week average, spot, etc.
- Assumptions concerning the structure of returns which under the DCF assumes that the price-earnings multiple, dividend payout ratio, and earned return will be constant.
- Whether single or multiple growth rates better reflect investor expectations.
- Choices concerning the use of historical or forecast growth rates.
- From a historical perspective, whether 10-years, 5-years, or some other historical period is representative of investor expectations.
- Choice among variables to measure growth, e.g., earnings per share, dividends per share, book value per share, cash flow per share, retention growth, price growth, etc.
- Choice of investor influencing growth rates that are available from I/B/E/S First Call, Zacks, Morningstar and Value Line.
- Whether the growth rate if measured by the formula "b x r" should be modified for external growth, i.e., "sv."
- The potential misspecification of the rate of return applicable to book value when taken directly from DCF if the market price diverges from book value.

Many of the assumptions, especially the constant price-earnings multiple, constant payout rate, and constant earned return, are particularly unrealistic. My point is that all models have their strengths and weaknesses, and it is important to rely on more than one model in determining the cost of common equity.

Q. At page 10 of his surrebuttal, Mr. Spadaccio specifically cites to the Aqua order. What arguments does he present there?

A. Mr. Spadaccio laments the Aqua Order for departing from long standing practice of stating the cost of equity in terms of the DCF. He fails to acknowledge that the Commission expressed the view that the DCF is slow to react to a rising interest rate/inflation rate environment.

Q. On pages 14-15 of his surrebuttal testimony, Mr. Spadaccio criticizes you for making specific exclusions to his DCF calculations. Please respond.

A. There is just no way that the DCF returns that I listed on page 12 of my rebuttal testimony can play any role in the determination of the equity return in this case. Mr. Spadaccio claims that the removal of the return for Chesapeake Utilities and ONE Gas only serves to inflate the DCF result. But an 8.65% DCF return for Chesapeake Utilities and 8.02% for ONE Gas cannot be useful to determine a fair return in this case. We know that 8.65% and 8.02% is too low based upon the other rate case decisions I report in my rebuttal testimony.

Q. At pages 11-14 of his surrebuttal, Mr. Spadaccio provided a lengthy discussion of the DSIC return and its relevance, or lack thereof, to base rate cases. Please respond.

A. Mr. Spadaccio goes to some length discussing the Quarterly Earnings Report. He acknowledges that the Commission awarded an equity return in the Aqua case that was above the DSIC quarterly rate for water utilities. This is not the first instance that the Commission has done so. In a variety of cases, the Commission has set the ROE near or above the DSIC rate. Two electric utility rate case decisions prove this point. In the UGI Electric rate case at Docket No. R-2017-2640058, the Commission set the rate of return on common equity at 9.85% when the DSIC return was 9.65% for electric utilities. In the PPL Electric Utilities rate case at Docket No. R-2012-2290597, the Commission set the return on equity at 10.40% when the DSIC return was 10.20% for electric utilities. Further, in the PECO Energy - Gas Division rate case decision, the Commission set the Company's equity return at 10.24% at a time when the DSIC return for gas utilities was 10.20% (Docket No. M-2021-3025288). Finally, the Commission set the return for Aqua Pennsylvania at 10.00% when the DSIC return for water companies was 9.80%. This long series of returns in base rate cases support returns higher than the prevailing DSIC return.

Q. At page 38 of his surrebuttal, Mr. Spadaccio compares the ROE request by UGI Gas to returns requested by other gas utilities. Please respond.

A. He observes that the Company's request in this case exceeds returns requested in other jurisdictions. These comparisons are invalid. Those returns relate to other cases filed prior to March 10, 2022. Most of the evidence that supported those requests predated the upward spike of inflation and interest rates that are reflected in the Company's request here.

Q. At page 22 of his surrebuttal testimony, Mr. Spadaccio claims that his use of spot stock prices in his DCF calculation and his use of analysis forecasts contain the most up-to-date projection of inflation. Do you agree?

A. No. Mr. Spadaccio used a spot price as of February 25, 2022 and March 1, 2022. These dates predate the acceleration of inflation that occurred in March and April 2022. So, just as the Commission noted in the Aqua case, the DCF lags investor concerns regarding inflation and higher interest rates. After all, the FOMC's actions to increase the Fed Funds rates occurred on March 16, 2022 and May 4, 2022, after Mr. Spadaccio measured his stock prices.

Q. Do you agree with Mr. Spadaccio where he states on page 12 of his surrebuttal testimony that the DSIC mechanism serves to lower a utility's risk? Mr. Garrett also makes the same argument at page 12 of his surrebuttal. Do you agree?

A. No. I explain on page 13 of my direct testimony why this is not correct.

Q. At page 21 of his surrebuttal testimony, Mr. Spadaccio asserts that financial institutions, such as banks, lend money based on actual book values. Has he offered any support for this assertion?

A. No. Banks lend money to utilities, including UGI Utilities, Inc., based on their ability to service that debt, including repayment. It is only based upon its future cash flows and the ability to permanently refinance short-term borrowings that banks extend credit to utilities. Mr. Spadaccio's argument has no merit.

Q. At pages 21-22 of I&E Statement No. 2-SR, Mr. Spadaccio claims that the market capitalization of a utility does not offer support for my leverage adjustment. Please respond.

A. Mr. Spadaccio cites to the Value Line reports where those amounts are related to the market value of equity and excludes debt. However, the Yahoo! Finance reports show that the "Enterprise Value" of a utility includes both its debt capital as well the market value of equity. This supports the fact that investors are well aware of the market value of a utility's total capitalization, including both debt and equity.

Q. On page 25 of his surrebuttal testimony, Mr. Spadaccio claims that less weight should be given to more distant forecasts because they are less reliable. Please respond.

A. I find his observations to conflict with his use of five-year projections of earnings growth in his DCF analysis. If reliance upon five-year projections, whatever their reliability, is okay for DCF purposes, then there is no reason to discount any of the projections of Treasury yields when looking for the appropriate risk-free rate of return in the CAPM.

Q. At pages 26-29 of his surrebuttal testimony, Mr. Spadaccio seems to imply that the evidence you used to support the size adjustment in the CAPM is not specific to utility stocks. Is this correct?

A. No. Mr. Spadaccio states on page 28 that the Fama/French study is not specific to utility stocks. But what Mr. Spadaccio has not acknowledged is that utility stock performance was used in the Fama/French study that makes the size adjustment relevant to utilities, and appropriate to consider in this case. Furthermore, the article by Annie Wong was deficient because it attempted to correlate betas with size. As Fama/French subsequently established, beta is not the correct measure to identify returns associated with the relative size of a company, either utility or non-regulated. Beta measures systematic risk, and the size of a company is an unsystematic risk. In addition, the size adjustment to the CAPM has been embraced by Federal Energy Regulatory Commission ("FERC").[1]

Q. What issues were contained in the surrebuttal testimony of OCA witness Garrett that require a response?

A. Mr. Garrett has addressed the following issues: capital structure, the DCF growth rate, results of the CAPM, leverage adjustment, and management performance.

Q. Has Mr. Garrett presented any new evidence that would justify departure from

[1] *See, e.g.*, Association of Businesses Advocating Tariff Equity, 171 FERC ¶61,154 (May 21, 2020).

the Commission's well-established practice of using Company's actual capital structure if it is reasonable?

A. No. At page 5 of his surrebuttal testimony, Mr. Garrett claims that he is not aware of a specific Commission policy on capital structure. In fact, the Company's FPFTY capital structure complies with the Commission's policy that supports the actual capital structure. The Commission has recently reiterated its position in the Order Entered May 16, 2022 in Docket No. R-2021-3027385, citing earlier orders in PPL Electric Utilities (2012), Columbia Gas Pennsylvania (2021), and PECO Energy-Gas Division (2021). Mr. Garrett says that the average debt ratio of my Gas Group supports his hypothetical capital structure ratios. Regardless, the range of capital structure ratios is the controlling factor that should be used to determine whether the Company's actual ratios are reasonable. The indicated debt ratios are 30.0% to 60.2% in 2020. Moreover, the Value Line forecasts show a range of 39.5% to 60.0% common equity for 2025-27. With this range, the Company's actual 55.12% common equity ratio for the FPFTY is reasonable and should be accepted in this case.

Q. Mr. Garrett suggests (see page 14 of OCA Statement No. 2-SR) that witnesses representing utility companies are inclined to use interest rate forecasts as a means to boost the risk-free rate of return in the CAPM. Please respond.

A. As a preliminary matter, interest rates and indeed all capital cost rates are influenced by investor expectations associated with future inflation. It has been reported recently that inflation has reached a 40-year high of 8.5% in March 2022 (the April rate was 8.3%). These inflation rates have not been seen since 1982. Future capital costs will be influenced by this fact and hence interest rate forecasts must be considered. It is necessary to understand the fundamentals surrounding those forecasts before making the blanket statement that the witnesses representing utility companies are inclined to use them in an attempt to increase the CAPM result. I do not dispute that in a low interest rate environment that forecasts of future interest rates generally trend toward higher rates than current rates. With the Fed Funds rate now moving above zero, there is little room for lower interest rates, at a time of increasing inflation. Likewise, during periods of high interest rates, which we have not seen for a long period, forecasts would trend toward lower rates. So the absolute level of interest rates must be considered when assessing the validity of the forecasts.

Q. Mr. Garrett further disputes your position regarding the Value Line betas and the market risk premium. Please respond.

A. On page 14 of his surrebuttal, Mr. Garrett disputes my adjustment to the Value Line betas. Notably, I have used the Value Line betas as a foundation just like all witnesses. I merely reflected the difference in financial risk attributed to the market value of the capitalization and book value of the capitalization. As to his arguments involving the equity risk premium (“ERP”) on page 15 of his surrebuttal, there is no support for the notion that the current ERP must be lower than the historical ERP because the historical data is widely employed in the investment and academic publications to provide a foundation for comparative performance. Moreover, I specifically analyzed the historical data in light of current and prospective interest rates. I incorporated the basic fact that risk premiums increase with lower interest rates and they decrease with higher rates. Mr. Garrett has failed to incorporate this reality in his analysis. Furthermore, I only used the historical data for one-half of my risk premium analysis. I also gave equal weight to forecasts in developing a risk premium that reflects investor-expectations of their required returns.

Q. At pages 17-18 of his surrebuttal, Mr. Garrett further opposes the Company's proposal for recognition of management performance. Mr. Spadaccio also opposes any recognition of the Company's management performance at pages 34-39 of his surrebuttal (I&E Statement No. 2-SR). Please respond.

A. Mr. Spadaccio asserts that recognition management performance is "nonsensical" in that higher equity returns should not occur for management initiatives that are funded by ratepayers. Mr. Spadaccio does acknowledge that the legislature authorized this approach and that the Commission has followed it. The Commission has a long history of recognizing management performance (either positively or negatively) in rate case decisions. If the Commission were to abandon its constructive ratesetting approaches, such as recognition of management performance, then its ranking by RRA would surely suffer.

Q. Does this conclude your rejoinder testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 8-RJ

Rejoinder Testimony of
Sherry A. Epler

Topics Addressed: **Test Year Sales and Revenues**
Revenue Allocation and Rate Design

Dated: June 1, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 8, on January 28, 2022, and my rebuttal testimony, UGI Gas Statement No. 8-R, on May 17, 2022.

Q. What is the purpose of your rejoinder testimony?

A. My rebuttal testimony responds to certain portions of the following direct testimony submitted by the Bureau of Investigation and Enforcement ("I&E"), the Office of Small Business Advocate ("OSBA"), and the Office of Consumer Advocate ("OCA"): (1) I&E Statement No. 4-SR, the surrebuttal testimony of Ethan H. Cline; (2) OSBA Statement No. 1-SR, the surrebuttal testimony of Robert D. Knecht; and (3) OCA Statement No. 3SR, the surrebuttal testimony of Jerome D. Mierzwa.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. No.

II. TEST YEAR SALES AND REVENUE

Q. In your rebuttal testimony, you noted how I&E witness Cline claimed he was using a 15-year regression analysis to develop his recommended usage per Rate R/RT hearing

customer, but in actuality, his workpapers revealed he was using a 5-year plus 1 month regression analysis. (UGI Gas St. No. 8-R at 10.) Does Mr. Cline agree with you in his surrebuttal testimony?

A. Yes. Mr. Cline acknowledges that his use of the 5-year and 1-month analysis was in error. (I&E St. No. 4-R at 21-22.)

Q. Despite this error, does Mr. Cline continue disagree with the Company's claimed present rate revenue for the fully projected future test year ("FPFTY")?

A. Yes. He has now presented the results of a 15-year regression within his surrebuttal testimony and quantified related updated sales and revenue adjustments. Specifically, Mr. Cline updates his recommendation, such that he now proposes the use of a projected average use per Rate R/RT heating customer for the FPFTY ending September 30, 2023, of approximately 90.0968 Mcf per year. (I&E St. No. 4-R at 21-23.) He then flows through his updated projection of average use per Rate R/RT heating customer to overall projected gas volumes, Rate R/RT present rate revenues, and surcharges. (I&E St. No. 4-R at 23-25.) Mr. Cline's suggested revised adjustment increases present rate revenue by $5,532,841. (*See* I&E Ex. No. 4-SR, Sch. 3, line 6.)

Q. Does the Company agree with Mr. Cline's revised 15-year analysis and his stated adjustment?

A. No. Mr. Cline's revised analysis remains flawed in terms of not meeting the criteria required for statistical significance, as discussed in detail in my rebuttal testimony (UGI Gas St. No. 8-R at 10-12), and should be rejected accordingly.

Q. Does Mr. Cline concede in his surrebuttal testimony that his regression analysis does not meet the criteria for statistical significance?

A. Yes. Mr. Cline applies the same criteria the Company utilizes to assess the statistical significance of his regression output, namely a review of the regression output P-values for the regression variables. (I&E St. No. 4-SR at 25.) On page 25 of his surrebuttal, he states that "[a]s shown on I&E Exhibit No. 4-SR, Schedule 2, all of the P-values, <u>except for X Variable 3</u> are below the 0.05 threshold." (I&E St. No. 4-SR at 25) (emphasis added). As I explained in my rebuttal testimony, "a well-established standard is that a P-value less than 0.05 means that the value is statistically significant, whereas a P-value greater than 0.05 means that the value is not statistically significant." (UGI Gas St. No. 8-R at 11.)

Notably, Mr. Cline does not dispute that his analysis contains a statistically insignificant variable. (I&E St. No. 4-SR at 25-26.) He also notes that his analysis is not statistically significant "according to the Company." (I&E St. No. 4-SR at 26.) However, the Company's approach of utilization of the P-values to determine statistical significance is not one that was made up by the Company. Rather, it is rooted in proper statistical analysis, as explained in my rebuttal testimony (see UGI Gas St. No. 8-R at 11-12). Thus, by Mr. Cline's own admission and in accordance with proper statistical analysis, Mr. Cline's 15-year approach – which lacks statistical significance – must be disregarded.

Q. If he has conceded that his regression analysis is not statistically sound, why does Mr. Cline continue to believe that a 15-year time period is appropriate for his residential heating use per customer regression analysis?

A. Mr. Cline claims that "statistical significance" should "not be the only factor in determining whether a use per customer adjustment is reasonable." (I&E St. No. 4-SR at 26.) Further, he asserts that "conditions that determine use per customer change over time and should no longer be considered representative of current trends." (*Id.*) Mr. Cline also then suggests that "a 50-year regression analysis would likely produce a result that is "statistically significant," but it is not reasonable to assume that data and usage trends from the 1960's, 1970's, and 1980's is indicative of customer usage patterns in 2022 and 2023." (*Id.*) I note that Mr. Cline does not provide any other factors that should be considered in evaluating the company's regression analysis.

Q. Do you agree with Mr. Cline's position?

A. No. The Company proposes an 18-year regression analysis, whose variables are all, indisputably, statistically sound. In contrast, I&E has proposed a corrected 15-year regression analysis, whose variables Mr. Cline admits are not all statistically sound. We are talking about a difference of 3 years between the Company's regression analysis and I&E's regression analysis, not decades. From my perspective, the Commission should rely on the Company's 18-year regression analysis, which no parties dispute as being statistically sound, as opposed to I&E's corrected 15-year regression analysis, whose own sponsoring witness concedes as being not statistically sound.

Furthermore, the Company has not suggested the use of a 50-year regression analysis or the use of data and usage trends stretching back to the 1960's, 1970's, and 1980's. Mr. Cline also provides no evidence that a 50-year regression analysis would produce a statistically significant result for the determination of residential heating use per customer. His testimony amounts to pure speculation about what a 50-year regression analysis would or would not show.

In the end, no reliable evidence or statistical principle supports the Commission accepting Mr. Cline's proposed 15-year time period – which does not demonstrate statistical significance – in lieu of the Company's 18-year analysis – which does demonstrate statistical significance. (*See* UGI Gas St. No. 8-R at 11-12.) Accordingly, Mr. Cline's recommended adjustment must be rejected.

Q. How did Mr. Cline address your rebuttal testimony demonstrating that I&E has been inconsistent in the number of years used in its regression analyses in prior cases, specifically using a 5-year and 1-month period in UGI Gas's 2022 base rate case, a 15-year period in UGI Gas's 2020 base rate case, and a 10-year period in UGI Gas's 2019 base rate case (UGI Gas. St. No. 8-R at 12)?

A. Mr. Cline states that "[t]he time periods selected by I&E were based upon the specific circumstances of each case." (I&E St. No. 4-SR at 22.)

Q. Does he elaborate or explain what those "specific circumstances" were?

A. No. He provides no clarification. Further, I can discern no "specific circumstances" in those cases that would require the use of varying periods for the regression analyses. However, one such reason would be if the selected period did not produce statistically sound results in that year's base rate case, so I&E had to select a different time period. The problem here is that I&E's selected period in this year's case does not produce statistically sound results, as I explained previously and as conceded by Mr. Cline. Thus, no reliable evidence or well-established principles of statistics support I&E's corrected 15-year regression analysis.

III. REVENUE ALLOCATION AND RATE DESIGN

A. REVENUE ALLOCATION AND RATE UNIFICATION

Q. OSBA witness Knecht points out an inconsistency in your testimony where you appear to be advocating a revenue allocation of both 2.0 times the system average increase for Rate R/RT and also 1.43 times the system average increase for Rate R/RT. (OSBA St. No. 1, pp. 7-8.) How do you respond?

A. Mr. Knecht is correct to highlight the discrepancy in my rebuttal testimony. To correct this discrepancy, lines 10-18 on page 14 of my rebuttal testimony should be struck.

Q. What is the Company's position on revenue allocation?

A. As noted in my direct testimony, the Company has goals of moving all classes of customers toward the system average return as part of its revenue allocation and also maintains a goal of achieving rate uniformity for Rate N/NT and Rate DS across the former UGI rate districts. To develop the full revenue allocation, the following principles should apply:

1. In continued attempt to unify Rate DS, the Rate DS revenue allocation should be determined by applying a revenue increase of 2.0 times the system average to the Rate DS former North Rate District rates.
2. Next, Rate DS for the former South and Central Rate Districts would be established by either (a) moving the Rate DS distribution charge for the former South and Central Rate Districts up to an equivalent unit rate to that of the Rate DS former North Rate District distribution unit rate (i.e., where the unit rate in step 1 above

for Rate DS former North Rate District is now above the current $2.9730/Mcf unit rate for the Rate DS former South and Central Rate Districts), or (b) leaving the current distribution unit rate unchanged (i.e., where the unit rate in step 1 above for Rate DS former North Rate District is still below the current $2.9730/Mcf unit rate for the Rate DS former South and Central Rate Districts).

3. Once the total net Rate DS change is determined from the summation of steps 1 and 2 above (inclusive of related DSIC roll-in revenues), the remaining revenue to be allocated to all other classes can be determined.
4. The remaining revenue increase determined in step 3 should then be allocated to Rate R/RT, Rate N/NT, and Rate LFD in a manner which would produce equivalent progress on a relative rate of return basis toward the system average return. This remaining increase would be inclusive of the DSIC roll-in amounts related to Rates XD and IS, in accordance with the rationale supporting this roll-in as found in the rebuttal and rejoinder testimony of Mr. Brown (see UGI Gas St. Nos. 1-R and 1-RJ).
5. As part of the final determination of Rate N/NT, the revenue allocation to this class should be apportioned in a manner which unifies the Rate N/NT former North Rate District with the former South and Central Rate Districts. Given the modest difference existing, this is readily accomplished in this proceeding.

The above revenue allocation determination includes elements of both gradualism (2.0 times system average return limits) as well as equitable impact (Rate R/RT, Rate N/NT, and Rate LFD all moving the same relative movement toward system average return).

B. RATE DESIGN - BALANCING CHARGES

Q. Does OCA witness Mierzwa recommend any changes to the Company's balancing service charges?

A. Yes. Despite Mr. Mierzwa now "no longer pursu[ing] the allocation of storage demand charges to Rate NNS" as a result of the Company's rebuttal (see OCA St. No. 3SR at 14), Mr. Mierzwa continues to claim that Rate MBS charges should be inclusive of pipeline storage capacity and demand costs at a level equivalent to the 5% maximum balancing tolerance which is permitted under Rate MBS service. (*See* OCA St. No. 3SR at 14-15.) This 5% is in contrast to the Company's *actual* storage use of 2.5737%, on which the Company's Rate MBS rate was designed. (*See* UGI Gas Exhibit SAE-8.) As alleged support, Mr. Mierzwa contends that, "Customers should be charged for the level of service they are entitled to and, therefore, it is appropriate to design the MBS rate based on the 5% percent tolerance." (OCA St. No. 3SR at 15.) Further, Mr. Mierzwa provides the following example:

> [C]ustomers under Rates LFD and XD are charged for the maximum daily quantity of service they are entitled to. These charges are not reduced if a customer does not utilize their maximum daily service entitlement. Similarly, PGC customers are charged for interstate pipeline capacity costs based on their expected design day demands, not their actual demands.

(OCA St. No. 3SR at 15.)

However, Mr. Mierzwa's example is flawed.

Q. Why is Mr. Mierzwa's example flawed?

A. While customers under Rates LFD and XD are charged based on their maximum daily quantity, and Purchased Gas Cost ("PGC") customers are charged for interstate pipeline capacity costs based on expected design day demands, both of these customer groups have direct access to assets and (by either capacity release or holding capacity directly). Thus, all these Rate LFD and XD customers, and the PGC, are able to utilize those assets when they are not needed to generate revenues which offset the costs of the capacity. This allows these customer groups to offset the fixed costs they pay related to their peak service capacity requirements.

By contrast, Rate MBS customers do not have direct access, and are not able to be provided direct access, to the storage assets backing up Rate MBS and cannot sell these assets for use by others into the market to generate revenues to offset Rate MBS charges. If Rate MBS customers were given storage capacity equivalent to their 5% tolerance, then Mr. Mierzwa's argument would have merit, as customers would then be able to sell that capacity to the market when they are not utilizing it and retain the benefit. However, because Rate MBS is provided by a shared set of storage assets with the PGC customers, it is the PGC that gets the use of unused storage assets which back up Rate MBS service, and it is the PGC that gets to monetize and retain the value of storage when it is not needed for system balancing.

For example, the Company regularly enters into Storage Asset Management Agreements with third parties. Those third parties pay for the right to manage those storage assets. The revenues from these arrangements are then subject to the PGC sharing mechanism and provide a credit to PGC customers and a sharing to the Company as an incentive to maximize related revenues. Rate MBS customers receive no form of credit against their costs for these Storage Asset Management arrangements. Because the PGC is monetizing the value of the storage capacity that is not required by the Rate MBS customers, in this case the capacity represented by the difference between 5% "permitted use" and the 2.5737% "actual use," Rate MBS customers should only be assigned costs representative of their actual use, as the Company has proposed in its Rate MBS rate design. This approach represents a fair allocation of storage costs between Rate MBS customers and other storage users.

Thus, Mr. Mierzwa's recommendation should not be adopted. However, if the Commission were to adopt Mr. Mierzwa's suggested 5% storage cost allocation for Rate MBS, it would then likewise need to direct that a sharing of the revenues generated by the use of these assets (when not being used by Rate MBS customers) be returned to the Rate MBS customer group.

IV. <u>CONCLUSION</u>

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 9-RJ

Rejoinder Testimony of
Timothy J. Angstadt

Topics Addressed: Leak Reductions

Dated: June 1, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Timothy J. Angstadt. My business address is One UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 9, on January 28, 2022. I also submitted my rebuttal testimony, UGI Gas Statement No. 9-R, on May 17, 2022.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to certain portions of the following surrebuttal testimony submitted by the Bureau of Investigation and Enforcement ("I&E"): I&E Statement No. 6-SR, the surrebuttal testimony of Jessalynn Heydenreich.

II. LEAK REDUCTIONS

Q. In her rejoinder testimony, Ms. Heydenreich states that the small increase in new leaks identified in 2021 over 2020 may indicate that the riskiest pipeline in the Company's pipeline system has not been replaced. (I&E St. No. 6-SR, p. 4.) Do you agree with her?

A. No, I do not. Ms. Heydenreich acknowledges in her testimony that the Company's pipeline assets are ranked annually through the Distribution Integrity Management Plan ("DIMP"), and that this process identifies the riskiest pipes for replacement. (I&E St. No. 6-SR, p. 4.) UGI Gas reviews its DIMP and risk ranking process with Gas Safety on a regular basis to ensure that its process is effectively identifying and reducing risk on the UGI Gas system. Further, as I noted in my rebuttal testimony, the Company does not use leak metrics alone to identify pipelines for main replacement and Ms. Heydenreich's concerns are already addressed within the Company's risk management process.

III. <u>CONCLUSION</u>

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 10-RJ

Rejoinder Testimony of
Constance E. Heppenstall

Topics Addressed: **Cost of Service Allocation**

Date: June 1, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Constance E. Heppenstall. My business address is 1010 Adams Avenue, Audubon, Pennsylvania.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted direct testimony, UGI Gas Statement No. 10, on January 28, 2022, and rebuttal testimony, UGI Gas Statement No. 10-R on May 17, 2022

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my rejoinder testimony is to discuss the surrebuttal testimonies of: (1) Robert D. Knecht, submitted on behalf of the Office of Small Business Advocate ("OSBA"); and (2) Jerome D. Mierzwa, submitted on behalf of the Office of Consumer Advocate ("OCA").

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Mr. Knecht rejects the allocation of manufactured gas plant ("MGP") remediation expenses, forfeited discounts, and other miscellaneous revenues based on sales volumes. (OSBA St. No. 1-S at 2-3.) Do you agree?

A. No. First, Mr. Knecht's focus on the past (stating that Manufactured Gas Plants were used under a different regulatory scheme and benefitted all customers) and his attempt to characterize remediation costs as an environmental tax are unsupported by any evidence. His surrebuttal testimony serves to distract from the fact that these assets historically served residential and small commercial customers and would do the same today if they were in operation. As such, these remediation expenses relate to the provision of safe and reliable service for residential and small commercial customers and should be allocated and included in the Company's Purchased Gas Cost ("PGC") calculation.

Second, as explained on pages 7-8 of my rebuttal testimony, these costs should be allocated in the same manner as they would be had the asset been in service, or based on Factor 1, which allocates costs to Rate R and Rate N customers based on firm service. These costs should not be allocated to all classes of customers as recommended by Mr. Knecht.

Q. Mr. Knecht rightly points out that the labor allocation was not updated within the sub-functionalization of Account 874. (OSBA St. No. 1-S at 3-4.) What is the effect on the cost of service in correcting this?

A. The allocation to the residential class changes by $73,909 or 0.015%, which is de minimis.

Q. Mr. Knecht also disagrees with OCA witness Mierzwa and the Company's revised allocation of reconnection revenues based on actual revenue by customer class, as he maintains that these revenues be allocated based on the cost for those reconnections. (OSBA St. No. 1-S at 4.) How do you respond?

A. In his surrebuttal testimony, Mr. Knecht simply references his rebuttal testimony as support for his position regarding Mr. Mierzwa's change in the allocation of reconnection revenues. (OSBA St. No. 1-S at 4.) As stated on pages 8-9 of my rebuttal testimony, I agree with Mr. Mierzwa's allocation, which is based on the actual revenues received by class, as the revenue should be allocated or credited to the class that contributed the revenue.

<u>SURREBUTTAL TESTIMONY OF JEROME D. MIERZWA</u>

Q. Mr. Mierzwa points to the Columbia Gas decision at Docket Nos. R-2020-3018835, *et al.* ("Columbia Gas Decision") in which the Pennsylvania Public Utility Commission ("Commission") approved the use of the Peak and Average ("P&A") method of

allocation. (OCA St. No. 3SR at 3.) Please discuss.

A. In citing the Columbia Gas Decision, Mr. Mierzwa neglects to mention that none of the parties in that case presented a cost of service study using the Average and Excess Method ("A&E Method), which is the cost allocation method recommended by the Company in this case. Therefore, the Commission could not adopt the A&E Method in the Columbia Gas Decision.

Q. In addition, Mr. Mierzwa states that in the PECO Energy Company – Gas Division rate case ("PECO Gas") Docket Nos. R-2020-3018929, *et al.*, the Commission found that the appropriate cost of service method for a natural gas distribution company should be determined on a case-by-case basis. (OCA St. No. 3SR at 3.) Please discuss.

A. Mr. Mierzwa is correct in his reading of the PECO Gas case. However, as stated on page 3 of my rebuttal testimony, there is precedent to using the A&E Method in UGI Gas's base rate cases. The Commission also approved the A&E methodology for a predecessor of UGI Gas in the PPL Gas Utilities Corporation ("PPL Gas") (subsequently UGI Central Penn Gas, Inc. and now part of UGI Gas) base rate case at Docket No. R-00061398 (referred to herein as the "PPL Gas Case"). Mr. Mierzwa's quote from the PECO Gas rate case provides no basis for the Commission to renounce the methodology utilized in UGI Gas's prior base rate cases. In fact, the Commission values consistency in the cost of service methodology utilized by a public utility in its base rate cases.[1] In addition, as stated in my rebuttal testimony, the P&A method of allocation implicitly double counts average demand and is not appropriate to use in this case. (UGI Gas St. No. 10-R at 3-5.)

[1] *See Pa. PUC v. PPL Elec. Utils. Corp.*, Docket Nos. R-2012-2290597, *et al.*, p. 113 (Order entered Dec. 28, 2012) (rejecting OCA's proposed cost of service methodology because, among other reasons, "PPL's proposed COSS in the instant proceeding is virtually identical to the COSS approved in 2020").

Q. In addition, Mr. Mierzwa quotes the PECO Gas order's statement that "PECO's distribution mains system garners considerable weight in the balance of mains costs" and points to his analysis that for UGI Gas, only approximately 10% of distribution mains costs are associated with meeting peak demand requirements. (OCA St. No. 3SR at 7.) Do you agree with his assessment?

A. In this statement, he relies on the calculation presented in his direct testimony purportedly showing that only 10% of mains costs are associated with meeting peak demands. (OCA St. No. 3SR at 7 n.18) (citing OCA St. No. 3 at 23). His analysis compares the cost differential between a 2-inch main and a 4-inch main, assuming that the 2-inch main is needed for average usage and the upsize to a 4-inch main is needed for peak usage. This analysis is flawed for two reasons. One, his calculation of 10% for peak demand only includes analysis for mains from 2-inch to 4-inch, whereas the Company has mains up to 12 inches in diameter, which are much more costly to install than a 4-inch line. Two, he assumes that the 2-inch line is only sized and used for average demand, where much of the 2-inch line's capacity would be used for peak demand.

Q. Mr. Mierzwa states on page 4 of his surrebuttal testimony that "assigning no peak demand related costs to interruptible customers is inconsistent with the use of A&E method in *Gas Rate Fundamentals*". (OCA St. No. 3SR at 4.) Do you agree?

A. No, I do not. On page 228 of *Gas Rate Fundamentals*, Fourth Edition, in the section titled "Peak Day Requirements," the text clearly states that "[w]here interruptible sales are included in the sendout data, these loads must be eliminated" in determining the peak day requirements.

Q. Mr. Mierzwa also refers to Mr. Paul Herbert's rebuttal testimony and workpapers in UGI Gas's 2020 base rate case at Docket No. R-2019-3015162 as proof that Gannett Fleming recommends that the Interruptible class should be assigned peak day demand. (OCA St. No. 3SR at 4-5.) Please discuss.

A. On page 11 of Mr. Herbert's rebuttal testimony, UGI Gas Statement No. 8-R, (which is attached as UGI Gas Exhibit CEH-1RJ), he assessed the <u>hypothetical</u> effect of moving some Interruptible customers to firm service and assigning peak day demand to this class. However, this exercise was clearly only a hypothetical calculation. The assignment of any peak day demand to the Interruptible class was rejected by the Company in the 2020 base rate case, contrary to what Mr. Mierzwa has implied in his testimony.

Q. Mr. Mierzwa also stands by his assertion that the Company's A&E method equates to using a peak allocation. (OCA St. No. 3SR at 5.) Do you agree?

A. No, A&E method differs by 3.37%. (UGI Gas St. No. 10-R at 7.) As stated in my rebuttal, "the difference between a pure peak allocator (of 0.5022) and my A&E factor (of 0.4685) is 3.37% less for Rate R under my A&E method versus a pure peak allocator." (UGI Gas St. No. 10-R at 5-6.) Accordingly, Mr. Mierzwa is wrong in concluding that the A&E Method is identical to a pure peak allocator. (UGI Gas St. No. 10-R at 6.)

Q. Mr. Mierzwa has revised his position regarding the recovery of costs related to manufactured gas plant remediation stating that it would be appropriate to deny UGI Gas recovery of these costs. Please discuss.

A. In Mr. Mierzwa's direct testimony, he recommends that the costs related to manufactured gas plant remediation be allocated based on Factor 12, a composite factor based on total operation and maintenance costs. Now, in surrebuttal, he states it would be appropriate that these costs be denied, and not recovered in base rates. Please refer to UGI Gas Statement No. 3-RJ, the rejoinder testimony of Vivian Ressler regarding this issue.

Q. Finally, Mr. Mierzwa, on page 30 of his surrebuttal testimony, shows a summary comparing OCA's study and the Company's Cost of Service Study. Do you have any comments on Mr. Mierzwa's summary?

A. Despite Mr. Mierzwa's differences regarding the Company's cost of service methodology, OCA's position regarding the cost to serve the Residential class is only $6,082,058 ($471,011,760 - $464,929,702) or 1.29% different than the Company's position. Thus, given the minor difference between the cost of service methodologies' results for the Residential customer class, I do not see any compelling reason for the Company to switch from the A&E method, which UGI Gas has consistently used for many years, to the P&A method proposed by Mr. Mierzwa.

Q. Does that conclude your rejoinder testimony?

A. Yes, it does.

UGI Gas Exhibit CEH-1RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2019-3015162

UGI Utilities, Inc. – Gas Division

Statement No. 8-R

Rebuttal Testimony of
Paul R. Herbert

Topics Addressed: Cost of Service Allocation

Date: June 19, 2020

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION
DOCKET NO. R-2019-3015162

RE: UGI Utilities, Inc. – Gas Division

REBUTTAL TESTIMONY OF PAUL R. HERBERT

Q. Please state your name and business address.

A. My name is Paul R. Herbert. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 8, on January 28, 2020.

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to certain portions of the following direct testimony: Office of Consumer Advocate ("OCA") Statement No. 4, the direct testimony of Jerome D. Mierzwa; Office of Small Business Advocate ("OSBA") Statement No. 1, the direct testimony of Robert D. Knecht; and Bureau of Investigation and Enforcement ("I&E") witness Statement No. 5, the direct testimony of Esyan Sakaya. Specifically, I will be addressing cost of service allocation issues.

Q. Are you sponsoring any exhibits with your rebuttal testimony?

A. Yes. UGI Gas Exhibit PRH-1R is attached.

<u>OCA Statement No. 4 – Jerome D. Mierzwa</u>

Q. Beginning on page 9 of OCA Statement No. 4, Mr. Mierzwa states that the Average and Excess (A&E) method you used in your cost of service allocation study (UGI Gas Exhibit D) does not produce a reasonable allocation of mains costs on the UGI system. Further, Mr. Mierzwa states on pages 21 and 22 that the Peak and Average ("P&A") method is the preferred method and that the Commission has provided guidance as to the appropriate cost allocations for natural gas distribution companies. Why did you use the A&E method?

A. The Commission's most recent decision and guidance in a fully litigated gas case approved my study and methodology using the A&E method. It was submitted in 2006 for the PPL Gas Utilities Corporation (subsequently UGI Central Penn Gas, Inc. and now part of UGI Gas) base rate case at Docket No. R-00061398. In my PPL Gas cost allocation study, I weighted the average use 40% and excess capacity 60%, based on the system load factor in a manner similar to the A&E method used in my Cost of Service Study (COSS, also referred to by Mr. Knecht as a Cost of Service Allocation Study or CSAS) for UGI Gas in this case. It is unclear why Mr. Mierzwa relies on gas cases from the early 1990's and ignores the most recent Commission decision and guidance concerning cost allocation methods.

Q. Why has the Commission preferred the A&E method over the P&A method?

A. The P&A method places too much weight on average use. In fact, the P&A method double counts the average demand because it uses average demand twice, *i.e.*, once in the calculation of average demand and again in the calculation of peak demand. This is evident because peak demand figures include the entire demand, including average use. Mr. Mierzwa's P&A allocator therefore double-counts average use and places little emphasis on the peak demands of customers that UGI must design its system to meet. The A&E method used in my study properly weights the portion of the system on average demands and the portion of the system on the excess capacity of peak demands.

Q. Please illustrate how the P&A method is flawed.

A. Take, for example, a system that has a peak day demand of 1000 units and an average day demand of 400 units. The peak and average method will give equal weight to the average demand of 400 units per day and to the peak day demand of 1000 units. But the 400 average day units are also included in the 1000 peak day units, so the average is counted twice. In the A&E method, however, the 400 average day units and the amount <u>over the average</u> of 600 units (excess capacity) are weighted based on the system load factor so that the average day demand is not double counted. The P&A method erroneously uses 1400 units (400 average and 1000 peak) as a basis for allocation rather than the actual 1000 peak day units used in the A&E method. Stated another way, my average and excess method would allocate 40 per cent of costs to average demand and 60% to peak demand; Mr. Mierzwa's method would allocate 57 per cent to average demand ((400 + 400) / 1400) and 43 percent to peak demand. It makes no sense, in my view, to allocate 57 per cent of costs based average demand on a system an average demand of 40 per cent, yet this is precisely the result achieved under Mr. Mierzwa's analysis.

Q. Your cost of service study, presented in UGI Gas Exhibit D, allocates the cost of mains based on the A&E method after assigning the cost of mains directly attributable to the XD-Firm and XD-I customers. Did Mr. Mierzwa object to that approach?

A. No. Although he did not mention or comment on the Company's approach to directly assign the cost of mains to the XD-F and XD-I customers, his workpapers submitted in Excel format clearly show that he uses the same costs directly assigned to the XD customers as presented in the Company's study.

Q. How did you allocate mains to the other classes?

A. I used the A&E method with no excess capacity allocated to the interruptible service class.

Q. Why did you conclude that no excess capacity allocated to interruptible customers was appropriate?

A. As explained in my direct testimony, interruptible service customers can be interrupted during periods of peak demand and UGI Gas's mains are designed to only meet the peak day requirements of firm service customers. Thus, the excess amount is zero.

Q. Did Mr. Mierzwa acknowledge that it is appropriate to allocate mains to the interruptible class as you did in Exhibit D?

A. No, to the contrary. His P&A study suggests his disagreement with my approach for the Interruptible customers. In his Peak and Average study, he uses the average day requirement for his Peak day portion of his allocation factor in addition to including the average usage in his average day component, further demonstrating the double counting of the average day usage. By using average day in his peak day component however, he agrees that there is no <u>extra</u> capacity assigned to the Rate IS class.

In my A&E study, I account for the average day usage once by using only the average day requirement for the IS class with no extra capacity.

Q. Have you considered an alternative to the allocation of mains to the IS class?

A. Yes. Please refer to my rebuttal testimony addressing Mr. Knecht, where I explain how my COSS (or CSAS) results would change if the portion of the IS customers which could be provided firm service were so moved into a firm class.

Q. Mr. Mierzwa claims that the use of your A&E method that weights the average and excess demands based on the system peak day equates to using a peak allocator. Do you agree?

A. No, I do not. Mr. Mierzwa's assertion that my A&E allocation is identical to a pure peak allocator is simply wrong. Table 3 on page 13 of his testimony clearly demonstrates that my A&E method does <u>not</u> produce the same result as a pure peak allocation. For example, the difference between a pure peak allocator and my A&E factor is 3.44% less for Rate R. When allocating over $1.5 billion in rate base for mains, this is a significant difference in result.

My A&E allocation is weighted based on a firm 2.5 peak day factor which results in a weighting of 39.6% for average day usage and 60.4% for extra capacity. The approximate 40/60 weighting is the same weighting used in my A&E cost of service study from the 2006 PPL Gas Utilities case, which was accepted by the Commission. Mr. Mierzwa's rejection of my A&E cost allocation, because he believes that it is a pure peak allocation, is unfounded.

Q. Did Mr. Mierzwa have other allocation revisions to your study?

A. Yes. He proposes revisions to the allocation of manufactured gas plant ("MGP") remediation expenses, customer deposits and other miscellaneous revenues.

Q. Do you agree with his revision to customer deposits?

A. Yes. At the time of filing the rate case, the customer deposits by rate class for the historic test year was not readily available, so the customer deposits for 2018 were used for Factor 21. During discovery, customer deposits for 2019 became available and the updated factor is reflected in my revised cost allocation study in UGI Gas Exhibit No. PRH-1R.

Q. Do you agree with Mr. Mierzwa's revision to the allocation of reconnection fees included in miscellaneous revenues?

A. Yes. During discovery, actual reconnection fee revenues by rate class for a recent twelve-month period was provided in response to OCA-VI-17. Based on this information, I calculated a new Factor 5A which allocates the FPFTY reconnection fee revenues as a credit to the allocated cost of service. This revision is also reflected in UGI Gas Exhibit PRH-1R.

Q. What does your UGI Gas Exhibit PRH-1R show?

A. I will discuss all the revisions reflected in UGI Gas Exhibit PRH-1R, which revises my original Exhibit D, in my rebuttal of Mr. Knecht.

Q. Do you agree with Mr. Mierzwa's revision to the allocation of expenses associated with manufactured gas plant remediation.

A. No, I do not. The remediation expenses relate to manufactured gas plants ("MGPs") which have been long retired and no longer produce gas supply. However, if these MGPs were still in operation, the gas produced and the associated costs would be included in the Company's Purchased Gas Cost ("PGC") calculation related to core market residential and small firm service. This is because, historically, the MGPs were overwhelmingly used to provide gas supply to residential and small commercial customers, rather than industrial customers. This historic use is fully described in the rebuttal testimony of Joseph

Kopalek, UGI Gas Statement No. 5-R. Therefore, it is appropriate to allocate remediation costs associated with the past provision of service to PGC customers to PGC customers.

Q. What do you conclude with respect to Mr. Mierzwa's cost allocation study?

A. Mr. Mierzwa's allocation of mains investment using the P&A method, which double counts the average demand, is unreasonable and inconsistent with the Commission's last fully litigated natural gas base rate case in *PPL Gas Utilities*. The Commission should use the Company's studies as a guide for revenue distribution in this case. As discussed above, his other allocation factors for the MGPs and the IS rate class are also inappropriate.

<u>OSBA Statement No. 1 - Robert D. Knecht</u>

Q. Please summarize OSBA witness Robert D. Knecht's recommendations concerning your COSSs.

A. Mr. Knecht (a) concludes that the Company's cost of service allocation study (CSAS) in Exhibit D is consistent with Commission precedent and sound cost allocation practices, (b) recommends separating the Rate XD-I customers from the Rate IS class, (c) recommends converting all Rate IS customers to firm service, and (d) proposes revisions to the allocation of certain cost items in the study.

Q. Mr. Knecht comments on pages 30 and 31 of his testimony regarding the

Company's methods for allocating the largest items in the CSAS, namely mains, meters and services. Please respond.

A. Mr. Knecht concludes that the Company's approach using the A&E demand allocator and incorporating the direct assignment of mains to XD customers is consistent with past practice and Commission precedent. He also accepts the Company's direct assignment approach for the allocation of meters and services which reflects the Company's more detailed analysis of deriving the actual cost by rate class.

Q. On page 31 or his testimony, Mr. Knecht recommends one change to the Company's CSAS methodology. Please explain.

A. Mr. Knecht recommends that the XD-I customers that receive interruptible service, should be included with the XD-Firm classification as they are more similar to the XD class than the rest of the Rate IS customers. I included the XD-I customers with the Rate IS class in Exhibit D because the XD-I revenue is included with the Rate IS class in the Company's revenue exhibit. However, I acknowledge the benefit and logic to Mr. Knecht's recommendation and I have moved the XD-I customers and their associated revenue into the XD-Firm class in my revised CSAS in UGI Gas Exhibit PRH-1R.

Q. What volumes did you use for the XD-I class?

A. In my original CSAS study in Exhibit D, I used an annual volume of 40,793,694 mcf for the XD-I customers. When preparing UGI Gas Exhibit PRH-1R, I discovered that volume was in error. The correct annual volume for XD-I customers is 42,584,155 mcf.

Q. Did you consider any other changes to the allocation of costs to the remaining Rate IS customer classification?

A. Yes, I did. In order to address the interruptible class issues raised by Mr. Knecht, I conducted an analysis using my revised CSAS in UGI Gas Exhibit PRH-1R that evaluated the hypothetical impact of moving 105 of the 371 Rate IS customers to firm service (those customers not requiring any distribution investment to provide firm service, or the maximum viable subset of Mr. Knecht's proposal). The analysis of the factors involved in actually migrating these Rate IS customers to firm service is further explained in the rebuttal testimony of Mr. Stoyko, in UGI Gas Statement No. 11-R, as is the Company's basis for rejecting Mr. Knecht's proposal. My analysis of the impact of migrating the 105 customers from Rate IS to firm service showed that doing so would have a nominal effect on the overall CSAS. Specifically, the proposal would increase the cost of service to the Rate IS class as a whole by $1.035 million, or from $13,840,769 to $14,875,200. As I noted previously, the Company does not agree with Mr. Knecht's proposal, and therefore UGI Gas Exhibit PRH-1R does not reflect his proposal.

Q. How did you conduct your analysis for the 105 Rate IS customers?

A. The Company identified, for each customer, their maximum daily quantity ("MDQ") and I reflected the extra capacity amount for these customers in the revised CSAS to assess the impact of Mr. Knecht's proposal.

Q. Please address the other minor changes that Mr. Knecht proposes to the allocation of certain cost items. Do you agree that the rounding mechanism in your CSAS model is problematic?

A. No, I do not. Any rounding in the allocation factors in my study is done to the nearest $1/100^{th}$ of one percent. The CSAS is used as a guide as to the approximate cost responsibility of each class. It is not necessary to achieve accuracy better than $1/100^{th}$ of a percent as a material difference would not result.

Q. Please explain Mr. Knecht's proposed revision for allocating meter costs.

A. In the last case, Mr. Knecht revised my meter allocation factor to reflect the Company's projected investment in telemetry equipment to provide daily readings for Rates DS, LFD, XD and IS customers. I agreed with his revision and I continued to reflect this allocation in the current case in Factor 6. However, the response to OCA-VI-3 indicates that such telemetry costs are included in Account 398, Miscellaneous Equipment rather than the meter accounts 381 and 385. My revised CSAS in UGI Gas Exhibit PRH-1R reflects this correction, by allocating the telemetry costs in Account 398 to the DS, LFD, XD and IS customers based on the number of customers and revising Factor 6 to exclude the telemetry equipment.

Q. On page 32 of OSBA Statement No. 1, Mr. Knecht recommends that the costs for remediating manufactured gas plant sites should be allocated to all rate classes (using Factor 2), not just Rate R and Rate N. Do you agree?

A. No, I do not, at least not the way he allocates such costs. In the last case, in order to eliminate the issue, I did not oppose his revision to remediation costs (using Factor 2 in my rebuttal exhibit) but only to the rate base portion of such costs, because it represented only a very small part of rate base. I continued to use Factor 2 for the rate base portion in this case but consistently used Factor 1 (allocation to Rates R and N only) for the O&M remediation costs. The O&M costs represent the current costs of remediation and, as described previously in discussing OCA's proposal regarding MGP costs, it is appropriate for these costs to be borne by the customer classes that historically were the overwhelming beneficiaries of their use, which were Rates R and N. As noted in response to Mr. Mierzwa's recommendation, this historic use is fully described in the rebuttal testimony of Joseph Kopalek, UGI Gas Statement No. 5-R.

Rates DS, LFD, XD and IS did not benefit from these production assets. Mr. Knecht's use of Factor 2, which allocates over 75% of remediation costs based on volumes to the Rate DS, LFD, XD and IS classes is unreasonable and distorts the results of his study.

Q. Mr. Knecht also proposes revisions to customer deposits and reconnection fees. Do you agree?

A. Yes. As indicated in my rebuttal testimony of Mr. Mierzwa, I have reflected these revisions in UGI Gas Exhibit PRH-1R.

Q. On page 33 of OSBA Statement No. 1, on Table IEc-2, Mr. Knecht makes a comparison of his CSAS rate of return by class with the results of your Exhibit D CSAS. Please comment.

A. The comparison of the studies shows only a relatively small difference in the rates of return under present rates by class, with the exception of Rates XD and IS. The larger variance for Rate XD is due to Mr. Knecht's study that allocates an unreasonable amount of remediation costs to the XD class as discussed above. The variance in Rate IS reflects that Mr. Knecht treats all Rate IS customers as firm, which has not been adopted by the Company as discussed above. The Table below compares rates of return under present rates of my original Exhibit D, with my revised CSAS in UGI Gas Exhibit PRH-1R, and also with the studies of OSBA and OCA.

Rate Class	Exhibit D	Exh. PRH-1R	OSBA-RDK w/ Firm IS	OCA Stmnt No.4
Rate R	3.23%	3.26%	3.49%	3.67%
Rate N	7.77%	7.76%	8.04%	8.65%
Rate DS	11.37%	11.38%	11.51%	11.31%
Rate LFD	12.90%	11.70%	12.75%	8.18%
Rate XD	12.86%	13.28%	8.93%	10.55%
Rate IS	16.55%	17.06%	12.53%	9.22%
Total	5.95%	5.95%	5.95%	5.95%

Q. What do you conclude regarding the above Table?

A. The rates of return for Rates R, N and DS are similar. The differences for Rates

LFD, XD and IS have been explained above. The important conclusion is that for all the studies submitted in this case, Rate R is significantly below the average rate of return and all other classes are significantly above the average rate of return. Any proposed revenue distribution approved in this case should recognize this fact. Under the Company's proposed rates, Rate R continues to be below the average rate of return while all other classes are above it.

<u>I&E Statement No. 5 – Esyan Sakaya</u>

Q. Please respond to the cost of service issues addressed in I&E witness Esyan Sakaya's Statement No. 5.

A. Mr. Sakaya does not oppose the Company's CSAS study. He only addresses the customer cost analysis and the recommended customer charges.

Q. What are his issues with respect to the customer cost analysis?

A. He recommends the removal of Account 912.1 Energy Efficiency and Conservation (EEC) program costs and to reflect forfeited discounts as a credit to customer costs.

Q. Do you agree with his revisions?

A. No, I do not. In fairness to Mr. Sakaya, the line item on my customer cost analysis (Schedule G of Exhibit D), is mis-labeled. The $244,334 expense that Mr. Sakaya is referring to is actually Account 908/912, Service Representatives, which is the cost for Company employees to handle customer account inquiries for Rate DS, LFD, XD and IS customer classes. Refer to Schedule E, page 2 of 4, on page 11 of Exhibit D under Sales Expenses, which shows the allocation of Account 908/912, Service Representatives to the customer component for Rate DS, LFD, XD, and IS classes. EEC program costs are also shown on the same page 11 of Exhibit D for Account 910.1, and are properly allocated to volumetric rate classes, based on the revenue received for EEC charges. As a result of this correction, his revision is not necessary or appropriate.

Q. Please explain why you oppose Mr. Sakaya's revision to reflect forfeited discounts as a credit to customer costs.

A. Mr. Sakaya's customer cost analysis is a <u>direct</u> cost analysis. Forfeited discounts, as a credit to customer costs, would be considered an <u>indirect</u> cost (credit). My fully-allocated customer cost analysis at the top of Schedule G of Exhibit D, properly reflects all <u>direct and indirect</u> customer costs, including the credit for forfeited discounts. The remaining part of Schedule G shows my direct cost analysis which excludes indirect costs and forfeited discount credits.

The purpose of preparing a direct customer cost analysis in support of customer charges is to determine the total monthly customer costs for customers that pay their bill on time. A proper direct customer cost should not be reduced for customers that do not pay their bill on time. In order to have proper guidance for the development of customer charges, the total direct customer costs should be considered without adjustments for indirect costs.

Q. How do your direct customer costs compare with Mr. Sakaya's direct customer costs?

A. Even with Mr. Sakaya's adjustments, his customer costs shown below for Rate R are within 99% of my Rate R customer costs and are identical for Rate N. His customer costs for the remaining classes are all within 96% of my customer costs.

Rate Class	Company Direct Costs per bill	I&E Direct Costs per bill
Rate R	$26.22	$26.05
Rate N	$42.74	$42.74
Rate DS	$226.54	$218.22
Rate LFD	$374.96	$366.64
Rate XD Firm	$834.75	$826.42
Interruptible	$309.19	$300.87

Q. Do the customer costs shown above fully support the proposed Rate R and Rate N customer charges proposed by the Company in this case?

A. Yes, they do. The Company proposed monthly customer charges of $19.95 for Rate R and $30.00 for Rate N. Both of these rates are substantially below the customer costs shown above.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 11-RJ

Rejoinder Testimony of
John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed: **Weather Normalization Adjustment**
Residential Customer Charge

Dated: June 1, 2022

Table of Contents

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400 Hilton Head Island, SC 29926.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes. I submitted my direct testimony, UGI Gas Statement No. 11, on January 28, 2022. I also submitted rebuttal testimony, UGI Gas Statement No. 11-R, on May 17, 2022.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to surrebuttal testimony of other parties relating to the Company's proposed Weather Normalization Adjustment ("WNA") mechanism and the proposed Residential Customer Charge. The surrebuttal testimonies of other parties addressed are as follows:

- Bureau of Investigation and Enforcement ("I&E") Statement No. 4-SR - surrebuttal testimony of Ethan H. Cline ("I&E witness Cline")
- Office of Consumer Advocate ("OCA") Statement No. 3SR - surrebuttal testimony of Jerome D. Mierzwa ("OCA witness Mierzwa")
- Office of Consumer Advocate ("OCA") Statement No. 4SR - surrebuttal testimony of Roger D. Colton ("OCA witness Colton")
- The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") Statement No. 1-SR – surrebuttal testimony of Harry S. Geller ("CAUSE-PA witness Geller")

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I. WEATHER NORMALIZATION ADJUSTMENT

Q. Please summarize OCA witness Mierzwa's surrebuttal testimony relating to the alleged appropriateness of a WNA deadband.

A. Mr. Mierzwa points to Columbia Gas of Pennsylvania, Inc.'s ("Columbia") 2020 base rate case, in which the Commission adopted the provision in the administrative law judge's Recommended Decision, which rationalized a deadband was reasonable "because it allowed for a range of what is considered normal weather."[1] Mr. Mierzwa then states that usage is affected by additional variables other than just temperature as support for a WNA deadband. (OCA St. No. 3SR at 19-20.)

Q. How does the fact that gas usage varies due to additional variables other than weather impact the appropriateness of a WNA deadband?

A. Mr. Mierzwa believes that since usage can vary due to wind and cloud cover that a deadband should be implemented. (OCA St. No. 3SR at 20.) However, these conditions should have no bearing on when a WNA mechanism is applied or is not applied, as these conditions exist at all times, including times when weather would be both within and outside a designated deadband. These factors do not stop with a deadband, and to rationalize that a deadband is appropriate as a result of these factors is errant logic.

Q. How do you respond to I&E witness Cline's request to implement a 3% deadband (I&E St. No. 4-SR at 2-5)?

[1] OCA Statement No. 3SR at 19.

A. Similar to Mr. Mierzwa, Mr. Cline cites the Columbia 2020 base rate case order, where the Commission determined a deadband provides "for a range of what is considered 'normal' weather in which the Company's Commission-approved rates would be applied without adjustment."[2] The quote cited by Mr. Cline starts with the following sentence, "The ALJ reasoned that without an extraordinary set of circumstances, there is no need for Columbia to reconcile day-to-day temperature variations that are part of normal business."[3] While Mr. Cline believes the conclusion that a deadband creates a range of "normal" weather still applies whether the adjustment is applied daily or monthly, I strongly disagree. The WNA uses the difference between actual and normal HDDs across a billing month, approximately 30 days. The Company's proposed WNA mechanism is not reconciling day-to-day temperature variations; it reconciles the difference between total normal HDDs used to set rates and total actual HDDs across a billing month. This is an important distinction since any variations in usage due to other variables (or a broader definition of normal weather) are averaged across the month and not incorporated in the day-to-day reconciliations that OCA and I&E are envisioning.

Q. Can you please summarize OCA witness Colton's surrebuttal testimony connecting the arrears for low-income customers with the proposed WNA mechanism?

A. Mr. Colton states that the WNA mechanism does not support low-income customers during winter months when there are more low-income customers in arrears, and they are deeper (higher percentage of income) in arrears.[4] He states that "the fact that on average, over

[2] I&E Statement No. 4-SR at 3-4.
[3] Docket No. R-2020-3018835, Order entered February 19, 2021, pp. 264-265.
[4] OCA Statement No. 4SR at 7.

multiple years, bills will be somewhat the same does not address the adverse impacts on low-income customers by taking bills that are likely already unaffordable and making them more so."[5] Finally, Mr. Colton states in his surrebuttal testimony, "To cite my conclusion without addressing the underlying data and discussion presented throughout my testimony does not serve to 'rebut' the data presented."[6]

Q. Does Mr. Colton provide evidence that the proposed WNA mechanism will disproportionately affect low-income customers?

A. No. Mr. Colton's conclusions presented in his surrebuttal testimony are that the WNA will increase bills in some winter months making these bills more unaffordable and that low-income customers are more sensitive to month-to-month variations and benefit from decreases in these variations, which can be achieved through budget billing. While the data presented in his direct testimony shows the seasonality of arrears, no data shows what impact the WNA will have on arrears for low-income customers.

Q. What conclusions can be drawn about the impact of the proposed WNA mechanism on low-income customers?

A. While Mr. Colton is correct that residential customers pay in arrears and that budget billing creates some bill stability, his conclusion that the WNA adversely impacts low-income customers is unsupported. The Company is happy Mr. Colton supports and cites benefits from the budget billing program, particularly for low-income customers who benefit from

[5] OCA Statement No. 4SR at 8.
[6] OCA Statement No. 4SR at 8.

lower month-to-month variations. In addition and complementary to budget billing, the proposed WNA mechanism will create more month-to-month bill stability, as each month's actual weather is considered. The fact there is a seasonality in the age and volume of arrears only shows that winter heating season bills lead to a higher volume of arrears. Protecting customers from colder-than-normal winter heating seasons is a benefit resulting from implementing the WNA mechanism, not an adverse impact on low-income customers, as expressed by Mr. Colton.

II. RESIDENTIAL CUSTOMER CHARGE

Q. Does OCA witness Mierzwa address the evidence you provided on the Residential customer charge?

A. No. In fact, when responding to Company witness Epler's testimony, Mr. Mierzwa still claims that, "UGI Gas' proposed customer charge reflects an increase of 37%. While on average UGI Gas' overall rate design may provide for gradualism, it would not provide for gradualism for customers with lower usage levels."[7] I provided evidence in rebuttal that states, "A customer who only uses 3 Mcf a month would only see a $2.27 difference in their bill under the $19.95 customer charge, representing a 6.93% difference, which meets the threshold of gradualism for this low use customer."[8] Further, Mr. Mierzwa does not address any evidence I presented relating to the impact of the proposed Residential customer charge on conservation. He simply claims that my testimony is similar to UGI Gas witness Heppenstall and UGI Gas witness Epler and previously addressed.

[7] OCA Statement No. 3SR at 11.
[8] UGI Gas Statement No. 11-R at 29-30.

Q. Did CAUSE-PA witness Geller mischaracterize your position on the impact and connection between the proposed Residential customer charge and energy conservation?

A. Yes. Mr. Geller's surrebuttal includes the following question, "How do you respond to UGI witness Taylor's argument that attempting to achieve residential bill reduction through energy efficiency measures is 'not an efficient use of our resources as a society' because it does not reduce the costs incurred by the utility?"[9] This, however, was not a point I made in my rebuttal testimony. I never stated nor is it my position that "attempting to achieve residential bill reduction through energy efficiency measures is not an efficient use of our resources as a society." While this misrepresentation may have allowed Mr. Geller to make additional points on the benefits of the Low Income Usage Reduction Program ("LIURP"), it does not address statements made in my rebuttal testimony.

Q. What is your position on the connection between the proposed Residential customer charge and conservation and energy efficiency?

A. Investing in energy efficiency measures to reduce residential energy bills is an appropriate goal that results in societal benefits. My rebuttal testimony and my position are that artificially setting customer charges lower than the fixed cost to serve to increase energy efficiency is not an appropriate regulatory approach and results in inefficient use of societal resources.

> "Although the consumer spent time and resources to "save" money, it does not reduce the costs incurred by the utility to provide service, i.e., any bill savings under a lower customer charge would exceed the actual savings of the resources

[9] CAUSE-PA Statement No. 1-SR at 18.

> used to provide service. Those costs are simply charged to some other customer or reduce the earnings of the utility. This is a zero-sum game; the gain to one customer by reducing how much they pay for fixed costs is the loss of either another customer or the utility itself."[10]

Energy efficiency measures reduce a customer's use of natural gas, saving money for that customer and society as less natural gas is consumed. However, this does not result in lower distribution costs for the provision of distribution service. Regardless, the fact remains that under the proposed Residential customer charge, 81.5% of a Residential customer's bill would be volumetric and provide for customer benefits from the reduction of usage achieved through energy efficiency. The amount of the customer charge also has not impact on the savings made from conserving on gas consumption.

Q. What is OCA witness Colton's position relating to the impact of the proposed Residential customer charge on low-income customers?

A. Mr. Colton attempts to make a connection between income and usage to support its claim that an increase in the Residential customer charge will adversely impact low-income customers who use less natural gas. Mr. Colton cites the 2015 U.S. Energy Information Association Residential Energy Consumption Survey ("EIA Survey") to demonstrate that low-income customers typically utilize less natural gas than high-income customers.

Q. How do you respond to Mr. Colton providing summary statistics relating to the Residential Energy Survey ("RECS") data?

[10] UGI Gas Statement No. 11-R at 31.

A. The use of data from the RECS survey should not trump the use of actual data provided by the Company. As such, the Commission should utilize the actual data provided by the Company related to the level of usage among low-income customers rather than a general region-wide survey. While high-level tables for the RECS survey may provide averages across regions, it does not accurately depict the accuracy of the survey results nor the percentage of low-income customers that may exhibit usage levels closer to moderate- and higher-income households.

Q. Does this conclude your rejoinder testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket Nos. R-2021-3030218, et al.

UGI Utilities, Inc. – Gas Division

Statement No. 12-RJ

Rejoinder Testimony of
Daniel V. Adamo

Topics Addressed: **Universal Service Programs**

Dated: June 1, 2022

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Daniel V. Adamo. My current business address is 1 UGI Drive, Denver, Pennsylvania 17517.

Q. Did you previously submit testimony in this proceeding on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company")?

A. Yes, I previously submitted my written rebuttal testimony and exhibits, UGI Gas Statement No. 12-R, on May 17, 2022.

Q. Are you sponsoring any exhibits with your rejoinder testimony?

A. Yes, attached to my rejoinder testimony is UGI Gas Exhibit DVA-1RJ.

Q. What is the purpose of your rejoinder testimony?

A. My rejoinder testimony responds to portions of the surrebuttal testimony of Roger D. Colton, submitted on behalf of the Office of Consumer Advocate ("OCA") (OCA St. No. 4SR).

Q. Do you have any overall comments regarding the scope of your rejoinder testimony?

A. Yes. My rejoinder testimony is limited to addressing certain new arguments raised by OCA witness Colton in his surrebuttal testimony, which was submitted on May 27, 2022. To the extent I do not address an argument by Mr. Colton, it should not be interpreted as my agreement with his position.

II. UNIVERSAL SERVICE PROGRAMS

Q. OCA witness Colton continues to argue that it is appropriate to establish his proposed "measurable outcome objectives" for the Company's Universal Service Programs in this base rate case as opposed to UGI Gas's Universal Service and Energy Conservation Plan ("USECP"). (OCA St. No. 4SR at 24-41.) Why does he believe that a rate case is the appropriate proceeding to establish his proposed outcome objectives?

A. According to Mr. Colton: "A rate case is the time and place to determine how the Commission will measure the effectiveness and efficiency of the use of ratepayer dollars. Decisions on how to achieve the objective will be left to the utility (subject to review through the USECP process). My decision to leave proposing solutions to the PUC process designed to consider such solutions was intentional." (OCA St. No. 4SR at 35.)

Q. Do you agree with his argument that this is the appropriate time and place to establish these objectives for the Company's Universal Service Programs?

A. Absolutely not. First, I am advised by counsel that the Commission's regulations set forth the goals for natural gas distribution companies' ("NGDCs") USECPs, requirements on the USECPs' contents, and processes for the review, approval, and ongoing evaluation of the NGDCs' USECPs. *See* 52 Pa. Code § 62.1, *et seq.* In fact, the Commission's regulations specify that "[t]he Commission will determine if the NGDC meets the goals of universal service and energy conservation programs," which includes "ensur[ing] universal service and energy conservation programs are operated in cost-effective and efficient manner." 52 Pa. Code § 62.3(a), (b)(4). Mr. Colton's claim that this rate case is actually the time and place to make that determination is incorrect, contrasts with the Commission's regulations, and is inconsistent with the Commission precedent that I identified in my rebuttal testimony, where the Commission declared that "all aspects" of Universal Service programs should be addressed in utilities' individual USECP proceedings, as opposed to base rate cases (see UGI Gas St. No. 12-R at 10.).

Second, it is unclear whether Mr. Colton proposes to apply these outcome objectives to the Company's existing USECP (which covers the five-year period of January 1, 2020, through December 31, 2025), the Company's next USECP to be filed in 2025, or both. Regardless of which, Mr. Colton fails to recognize the issues with proposing these outcome objectives in a base rate case as opposed to the USECP proceeding.

Indeed, to the extent that Mr. Colton expects that these outcome objectives be applied to the Company's existing USECP, UGI Gas's existing USECP was designed to achieve the goals and objectives set forth in the USECP within budget. Mr. Colton has presented no evidence that the Company can reasonably achieve his proposed outcome objectives under its existing USECP in a cost-effective and efficient manner. Indeed, Mr. Colton's outcome objectives were neither factored into the Company's design of the USECP, nor proposed by the OCA in its Comments on the Commission-approved USECP. Therefore, the Commission should not evaluate the performance of the existing USECP under Mr. Colton's proposed outcome objectives in this base rate case proceeding.

On the other hand, to the extent that Mr. Colton wants these outcome objectives to be applied to the Company's next USECP that will be filed in 2025, it still does not make sense to propose these outcome objectives in this base rate case. Essentially, Mr. Colton's recommendation would boil down to establishing three "objectives" for the Company's

USECP in the Company's 2022 base rate case, but then kicking the proverbial can down the road to UGI Gas's next USECP filing in 2025 to figure out how the Company can or will achieve those objectives. This misalignment in the establishment of goals and the designing of an USECP that can achieve those goals is precisely why Mr. Colton's recommendations are best left for the Company's USECP proceeding. Indeed, Mr. Colton fails to explain what happens if the USECP cannot be designed within budget in 2025 to achieve these "measurable outcome objectives" he proposes to be established in 2022. Moreover, I am aware of no Commission process by which the Commission establishes objectives for a utility's programs: (1) <u>three years</u> before the utility designs and proposes those programs; and (2) without any formal analysis of whether those objectives are reasonably achievable by the utility within its budget.

Q. Mr. Colton asserts that you "ha[ve] the review process backwards" because "UGI Gas should be asking what can be done differently or more effectively in order to improve the outcomes." (OCA St. No. 4SR at 37.) Has the Company been continually evaluating its USECP program performance and determining what improvements can be made?

A. Yes. The Company continually monitors and evaluates USECP program performance. For instance, on a quarterly basis, the Company evaluates LIURP performance and has discussions with its Community Based Organizations ("CBOs") and LIURP contractors regarding actual performance versus projected performance, spending forecasts, areas of success, and challenges with the program. Regarding the CAP, the Company has been performing outreach to those who have failed to recertify in an attempt to get them back into the program if still eligible. Also, the Company solicits customers who have received Low-Income Home Energy Assistance Program grants but are not yet enrolled in CAP. Additionally, the Company facilitates Universal Service Advisory Committee meetings semi-annually with numerous stakeholders in attendance. During these meetings, the Company reviews current year USECP performance and solicits feedback from attendees regarding potential areas of improvement. Finally, the Company participates in industry meetings to discuss various challenges peer utilities are facing and suggestions for improvement, of which many topics and brainstorming sessions are related to USECP performance. As a result of these efforts, the Company continues to make year over year progress with its USECP performance, as described throughout my rebuttal testimony (UGI Gas St. No. 12-R).

The bottom line is that the Company has been doing exactly what Mr. Colton says UGI Gas should do in the quoted passage—"asking what can be done differently or more effectively in order to improve the outcomes." Even in the absence of his proposed "measurable outcome objectives," the Company will continue to do so. Therefore, Mr. Colton's proposed objectives, even if properly raised in this base rate case, are unnecessary.

Q. Is Mr. Colton correct that you oppose "the creation of *any* measurable objectives by which to measure UGI Gas performance" (OCA St. No. 4SR at 32.)

A. No. That is not an accurate statement. I oppose the "measurable objectives" proposed by Mr. Colton in this base rate case for the reasons outlined in my rebuttal and rejoinder testimony. However, I support establishing metrics by which to evaluate the Company's Universal Service Programs' performance, so long as those metrics are fair, reasonable, well-designed, and properly established in the Company's USECP proceeding or in a general Commission rulemaking proceeding. I do not believe Mr. Colton's proposed metrics meet any of those characteristics.

Q. Mr. Colton also asserts that your objections to the establishment of his outcome objectives is "inconsistent" with UGI Gas witness Brown's rebuttal testimony about the impacts of inflation on the Company, because, according to Mr. Colton, the Company wants to address the impacts of inflation on the Company now but wait to address the impact of inflation on low-income customers until its next USECP in 2025. (OCA St. No. 4SR at 28-29.) Would you please respond?

A. As stated in my rebuttal testimony, the Company continually tries to promote internal and external programs to maximize customer participation, which ultimately reduces financial burdens on the participating customers. Most notable is the Company's current Energy Burden filing pending approval at the Commission.

Q. Mr. Colton also continues to argue in his surrebuttal testimony that "[t]he customer satisfaction of UGI Gas customers does not support an adder to the Company's equity return for exemplary management," arguing, among other things, that the Company's reliance on "external customer satisfaction surveys." (OCA St. No. 4SR at 19-20.) Please respond.

A. The Company utilizes a number of resources to gauge customer service performance and customer satisfaction, such as Verint (formerly known as Foresee), which has a sample size five times larger than that represented in the statistics cited by Mr. Colton. UGI Gas also utilizes a J.D. Power Gas Utility Residential Customer Satisfaction Study(SM) to measure satisfaction across six factors: billing and payment, corporate citizenship, price, communications, customer service, and safety and reliability. The Company has received high marks on its customer service from these independent and very well-regarded analytical services. See UGI Gas Exhibit DVA-1RJ to see the results of JD Power and Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Residential study by Escalent.

It is also important to note that the Commission's customer service performance report for 2021 has not been released yet. The data set forth in that report would be more current and truly show the impacts from COVID-19 on overall customer service performance metrics on all natural gas distribution companies. However, such data is not currently available, and Mr. Colton does not present any alternative data in his surrebuttal testimony on the Company's customer service performance in 2021. Thus, the more current, reliable, and independent third-party studies relied upon by the Company should be utilized instead of the data cited by Mr. Colton.

Q. Mr. Colton also tries to defend his claim that the increased residential customer charge will remove 95.4% of federal fuel assistance being delivered to UGI Gas's low-income customers, by asserting that he made no assumption that all 153,437 low-income customers received federal fuel assistance funding. (OCA St. No. 4SR at 21.) Would you please respond?

A. Mr. Colton misses my point. In his direct testimony, he asserted that "[t]he total increase in unavoidable fixed charges to the UGI Gas low-income population is thus $9,850,655

($64.20 x 153,437)." (OCA St. No. 4 at 9.) He then compared that dollar figure to the "total of $10,325,947 in LIHEAP grants in 2021." (*Id.* at 9-10.) From that comparison, he asserted that "[t]he increased customer charge standing alone, in other words, will remove 95.4% of the total value of federal fuel assistance being delivered to low-income customers." (*Id.* at 10.) Therefore, I responded in rebuttal that his point is flawed because, among other reasons, it is based on a false assumption that all of the 153,437 low-income customers receive LIHEAP grants.

Now, in his surrebuttal testimony, Mr. Colton asserts that he made no such assumption. However, without such an assumption, albeit erroneous, there cannot be a valid comparison between the estimated increase in customer charges for the low-income population and the total LIHEAP grants awarded. Effectively, Mr. Colton is taking a figure derived based on the total low-income population (*i.e.*, his projected increase in customer charges for the low-income population) and comparing it to a figure that is limited to a select portion of the low-income population (*i.e.*, the total LIHEAP grants awarded in 2021). Indeed, not every low-income customer received LIHEAP grants in 2021. Therefore, a proper analysis would be to investigate how the proposed increase in the residential customer charge would affect the low-income customers who actually received LIHEAP grants in 2021.

Here, 23,819 low-income customers received LIHEAP grants in 2021. Therefore, if the Company's proposed increase in the residential customer charge results in an additional $64.20 per low-income customer on an annual basis, then the total increase for the LIHEAP grant recipients would be $1,529,180 (*i.e.*, $64.20 x 23,819 = $1,529,180), which is substantially less than the $9,850,655 "total increase" in customer charges for low-income customers calculated by Mr. Colton. Thus, the Commission should reject Mr. Colton's claim that 95.4% of federal fuel assistance to low-income customers would be offset by the proposed increase in the residential customer charge.

III. CONLUSION

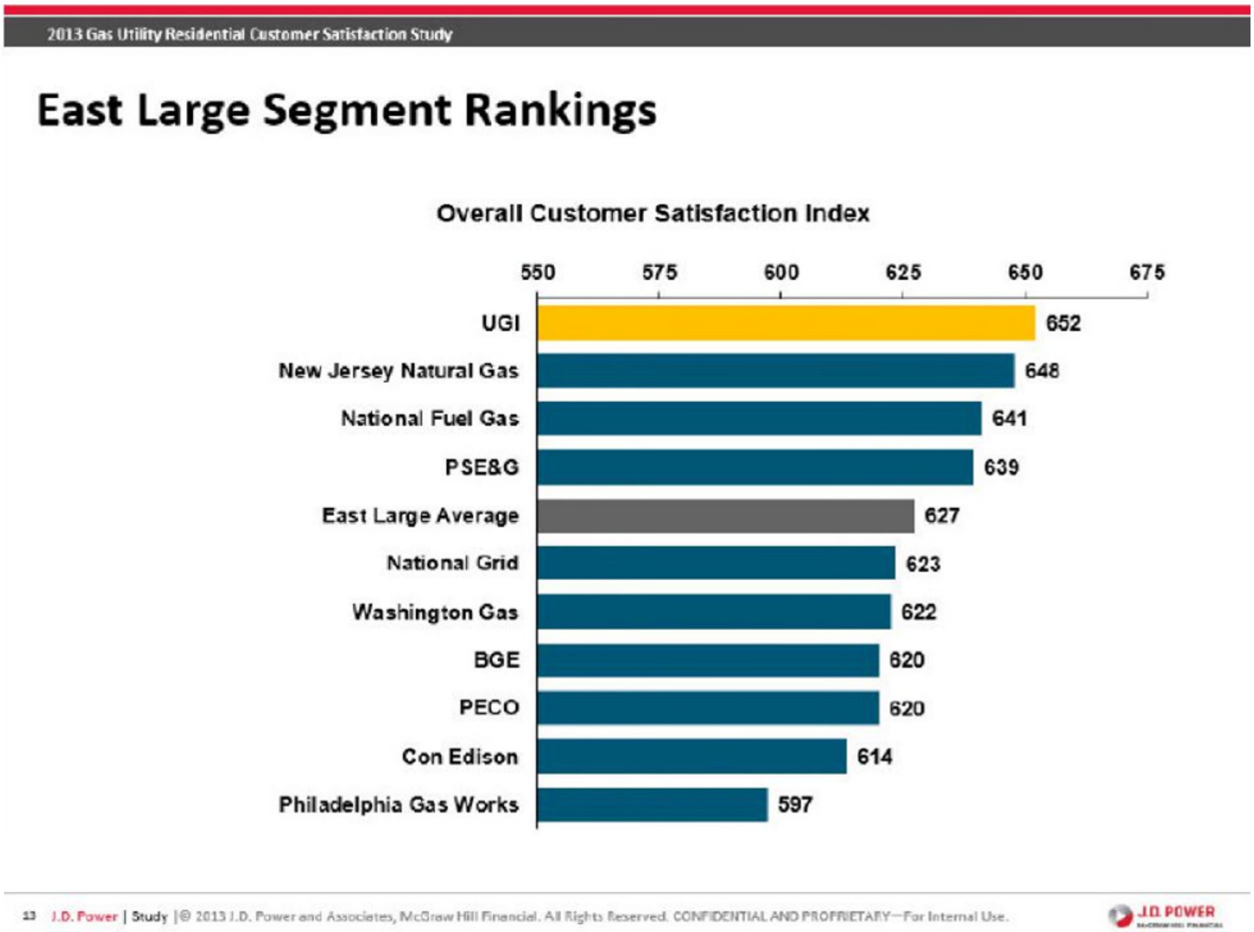
Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

UGI Gas Exhibit DVA-1RJ

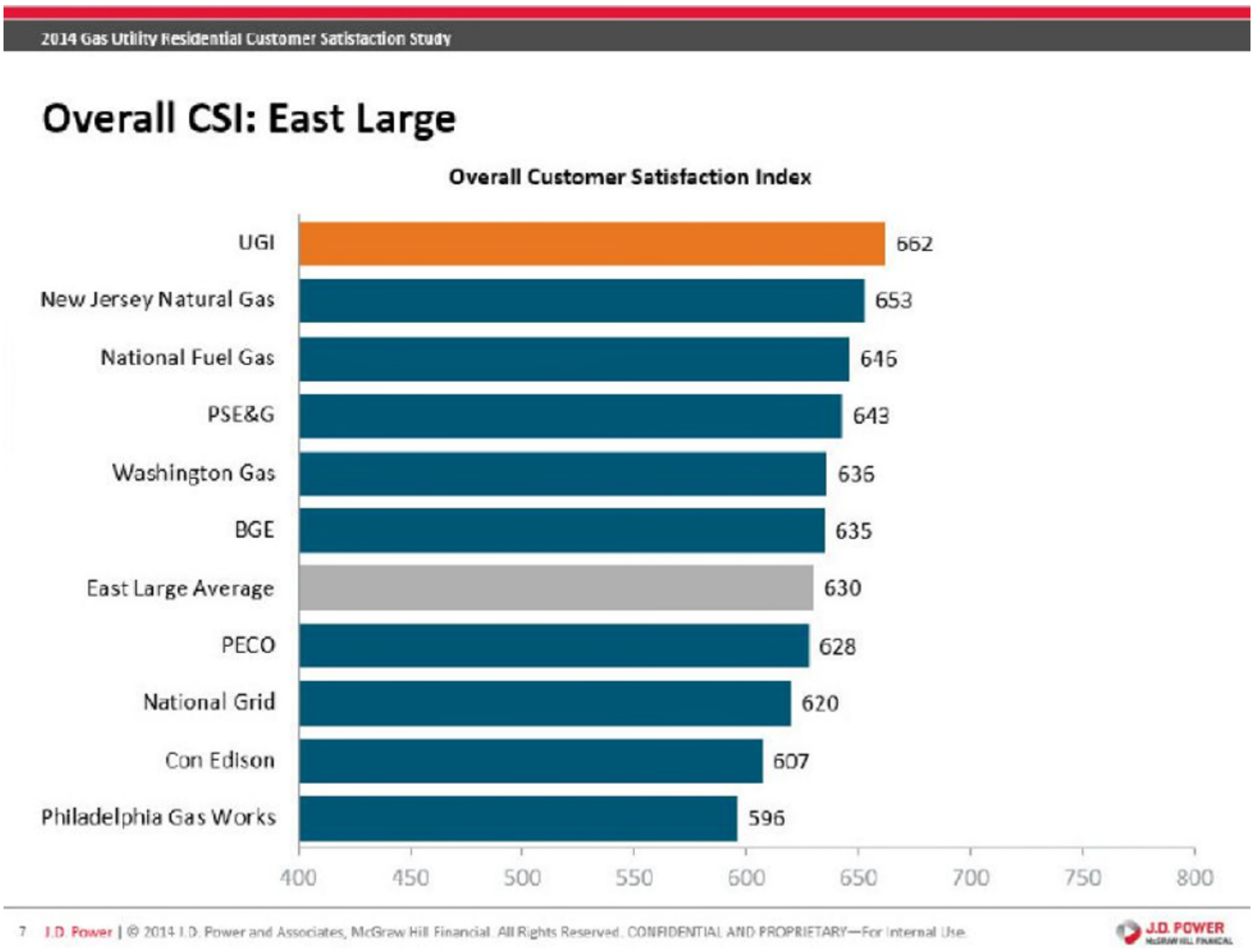
JD Power Gas Utility Residential Customer Satisfaction Study Results 2013-2021

2013



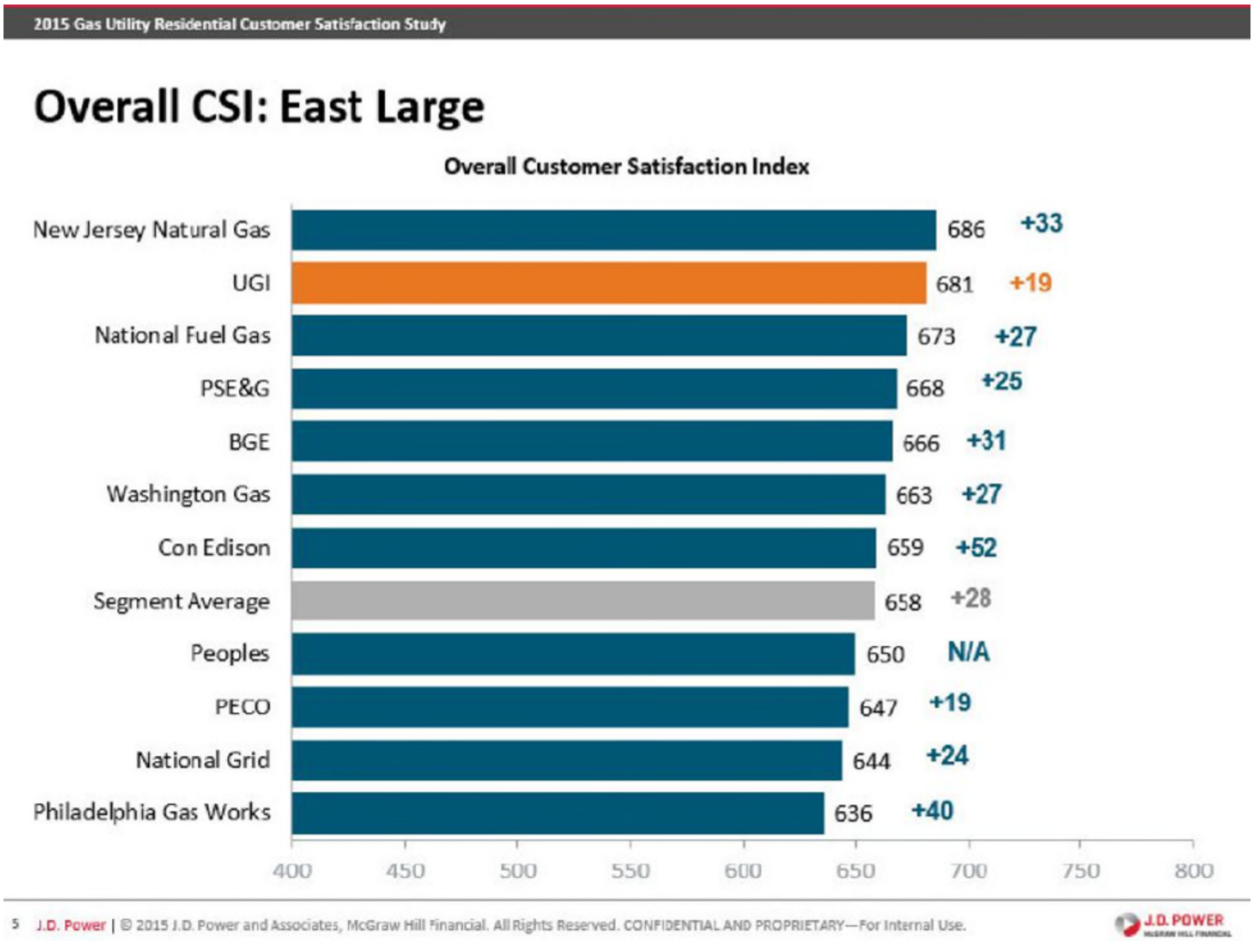
JD Power Gas Utility Residential Customer Satisfaction Study Results 2013-2021

2014



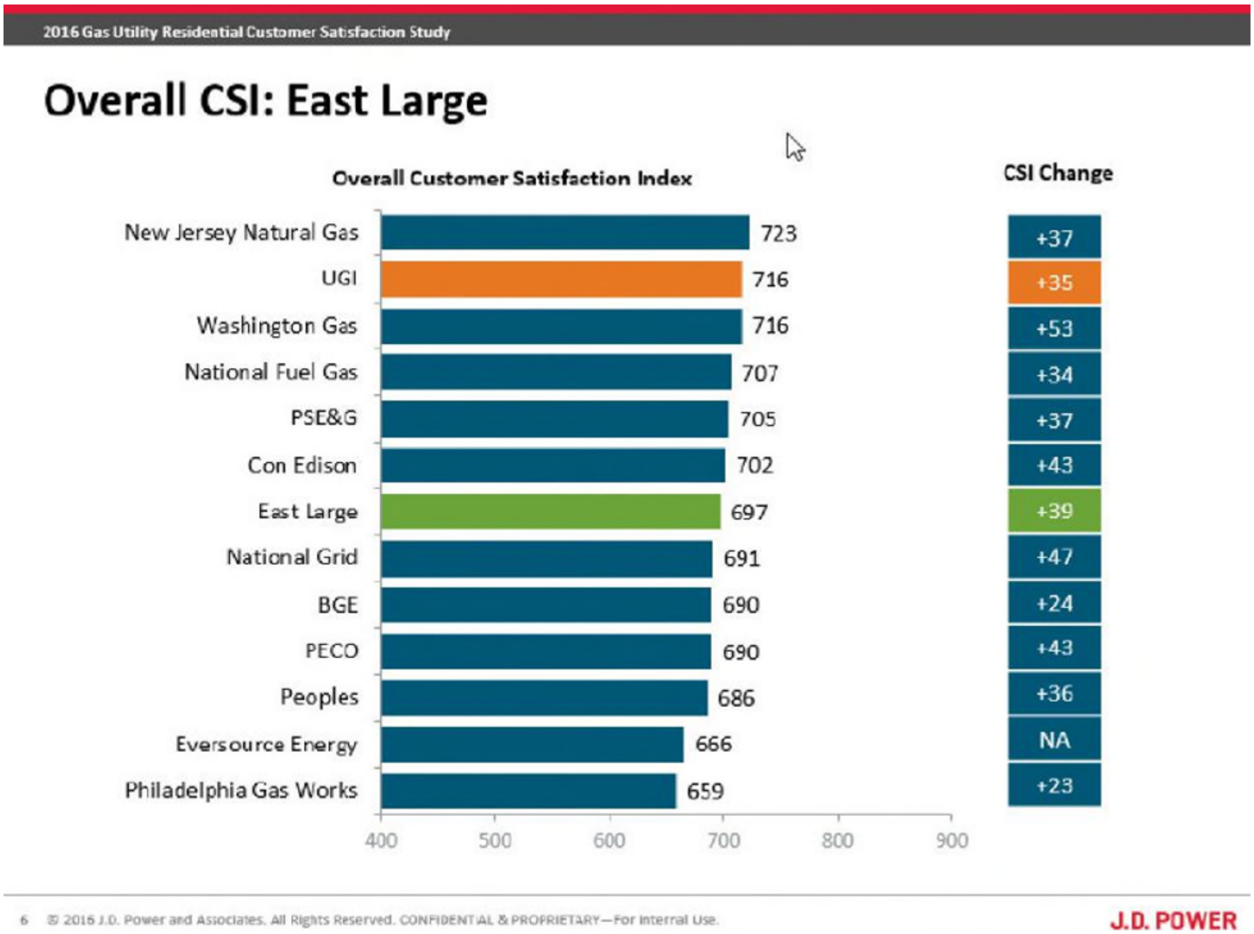
JD Power Gas Utility Residential Customer Satisfaction Study Results 2013-2021

2015



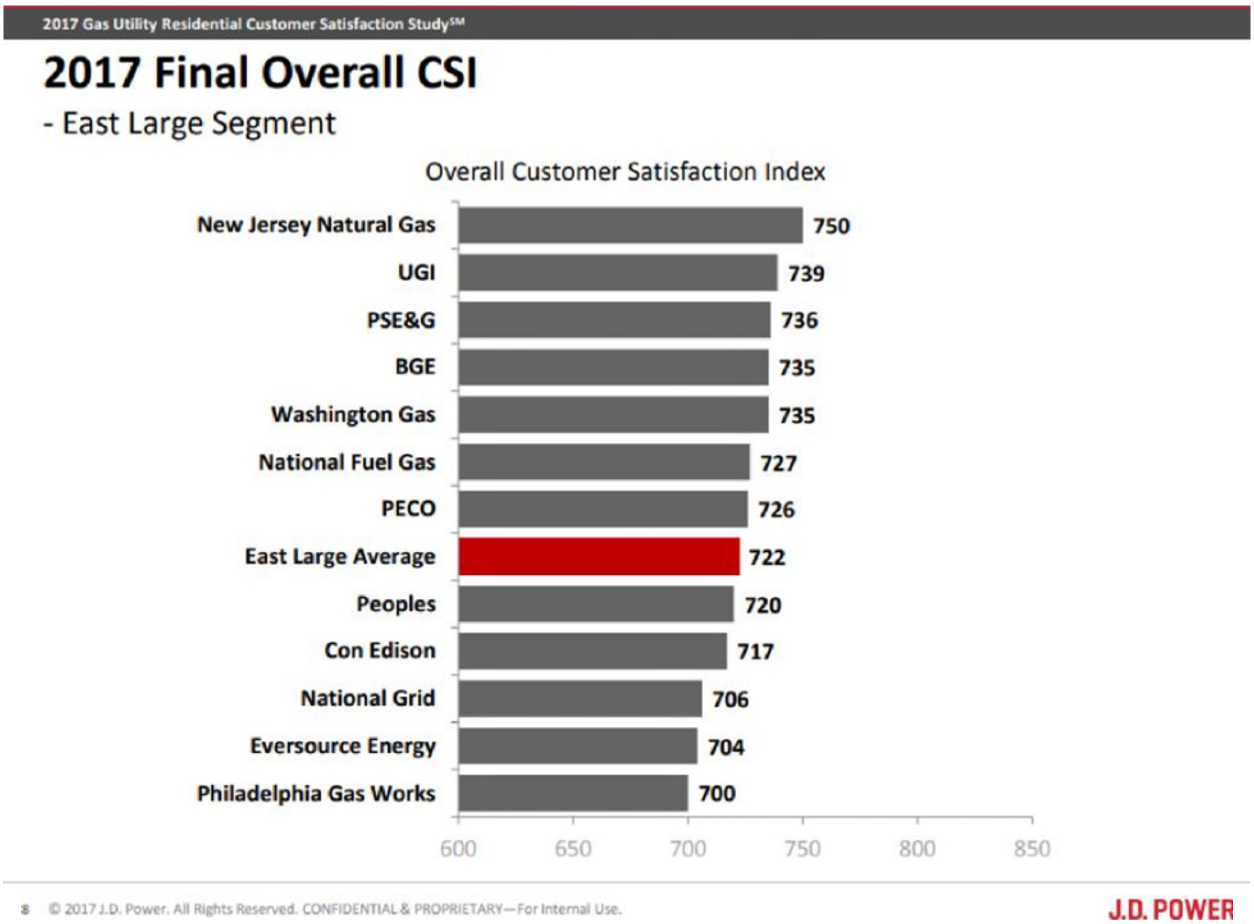
JD Power Gas Utility Residential Customer Satisfaction Study Results
2013-2021

2016



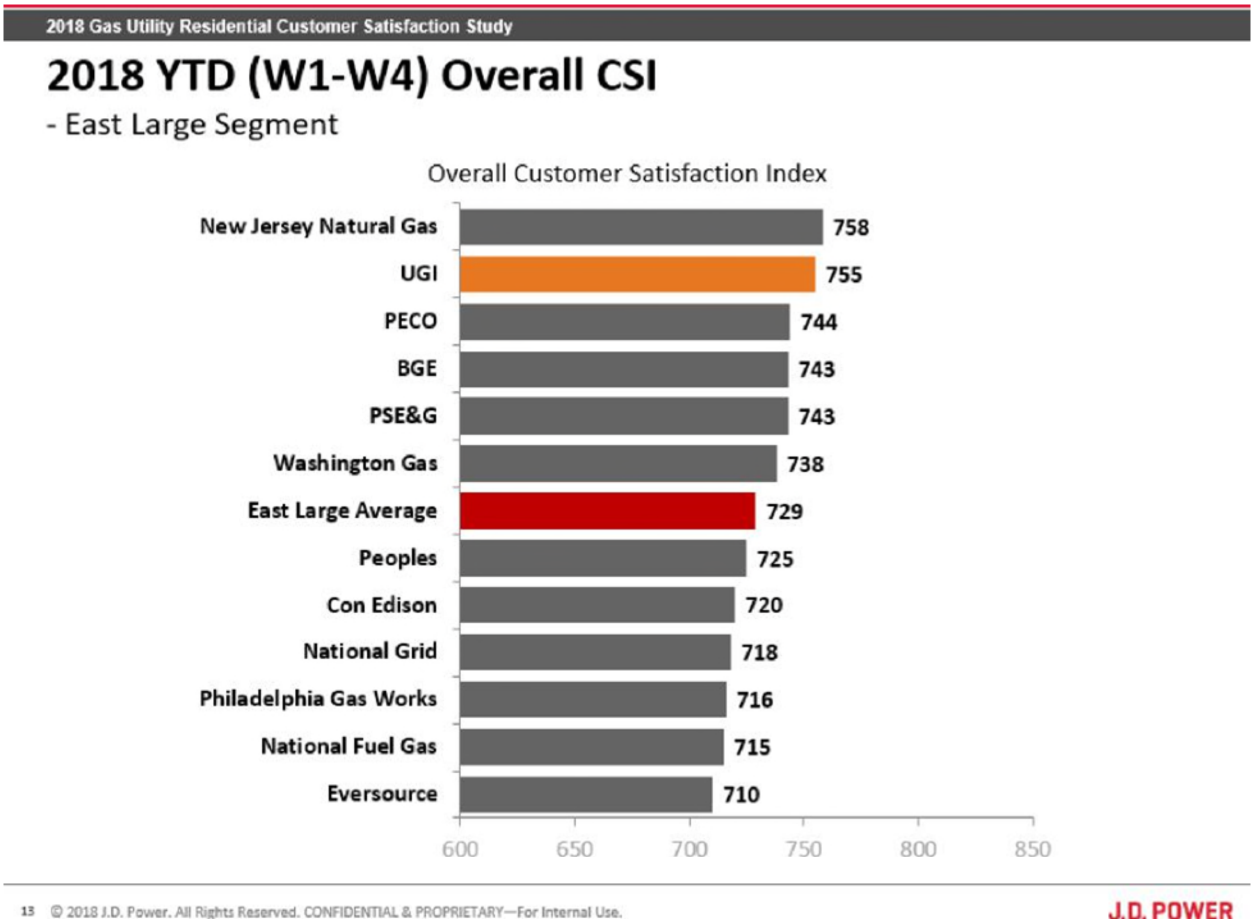
**JD Power Gas Utility Residential Customer Satisfaction Study Results
2013-20121**

2017



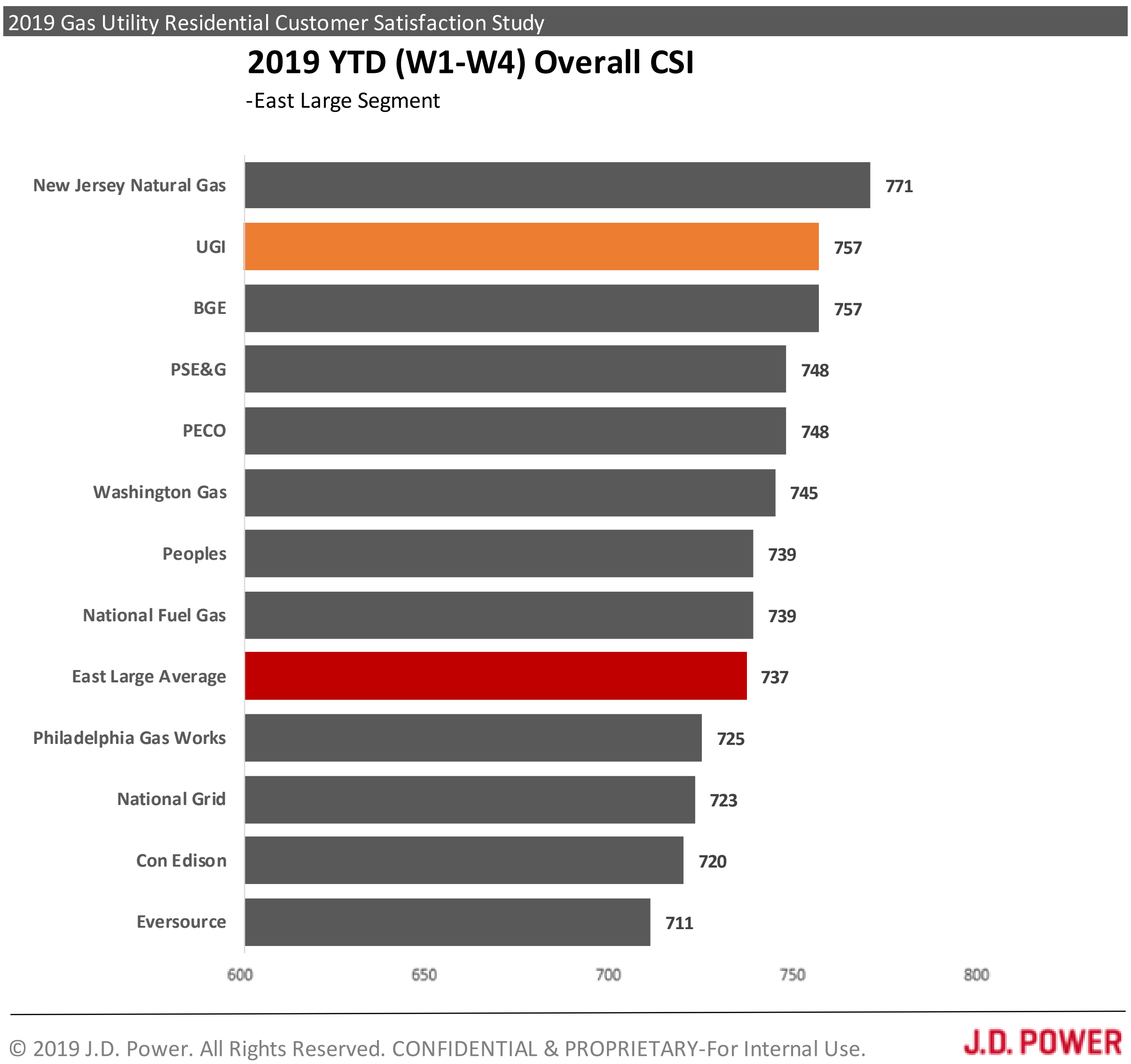
JD Power Gas Utility Residential Customer Satisfaction Study Results
2013-2021

2018



JD Power Gas Utility Residential Customer Satisfaction Study Results 2013-2021

2019



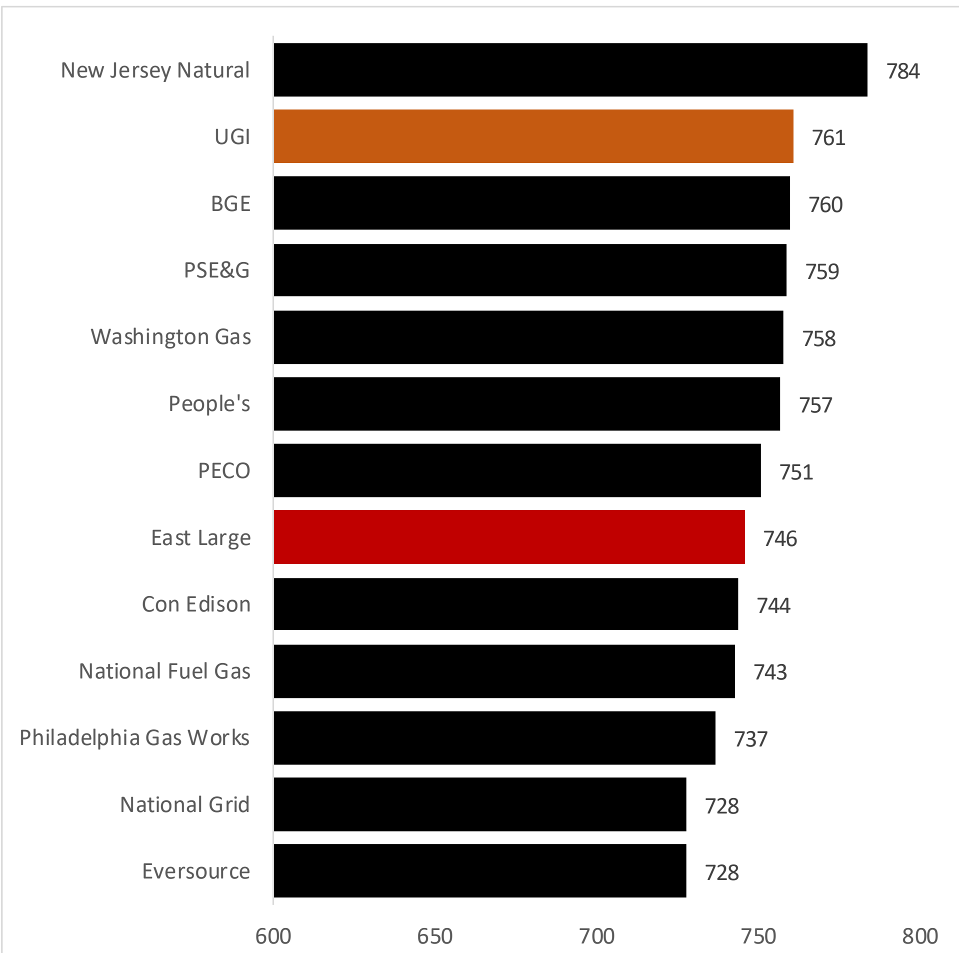
JD Power Gas Utility Residential Customer Satisfaction Study Results 2013-2021

2020

2020 Gas Utility Residential Customer Satisfaction Study

2020 YTD (W1-W4) Overall CSI

-East Large Segment



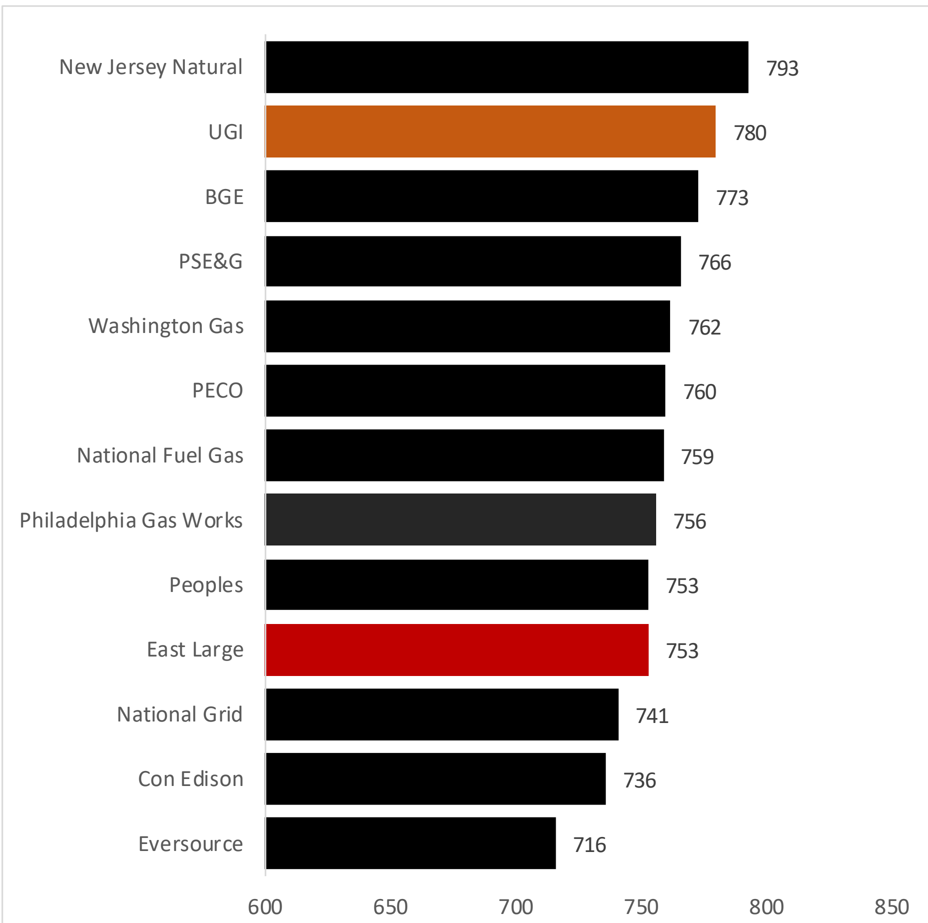
JD Power Gas Utility Residential Customer Satisfaction Study Results 2013-2021

2021

2021 Gas Utility Residential Customer Satisfaction Study

2021 YTD (W1-W4) Overall CSI

-East Large Segment



Escalent Most Trusted Brand Awarded to UGI in 2019, 2020, 2021

Year	Score
2019	727
2020	725
2021	742

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News

Stronger Community and Communication Skills are Building Utility Trust

JUNE 25, 2019

32 Utilities Named Most Trusted Brands

Community Support and Communications Effectiveness increase Americans' trust in their utility. According to customers, utilities are earning trust by encouraging employee volunteering, listening to community feedback and making consumers more aware of local support and charitable giving. Customers were also happier with the information utilities communicated and the mediums used to deliver those communications. These and other findings are from the 2019 Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Residential report from Escalent, a top human behavior and analytics firm.

The study's composite Brand Trust index score increased 1 point to 688 (on a 1,000-point scale) this year. Among the six components included in the Brand Trust index, Community Support and Communications Effectiveness increased the most. Building Brand Trust provides a positive return on investment for the industry as customers increasingly rely on utilities to provide energy innovation and are more likely to support higher rates for that innovation. Moreover, the study shows that as public trust grows, utilities become much more credible than state governments and regulators to lead industry innovation and progress.

"The nation's best utilities are trusted energy advisers whose consumers value their opinions and recommendations," said Chris Oberle, senior vice president at Escalent. "Industry regulators who are looking to shape the future of energy need to encourage the utilities they regulate to focus on building brand trust. Otherwise, our research finds that innovations in clean energy, EV expansion, consumption management, and digital services are going to languish on low consumer demand for utility-developed offerings."

Of the 140 utilities included in the Utility Trusted Brand & Customer Engagement: Residential study, 14 significantly improved on Brand Trust and 14 significantly declined, creating a 214-point gap between the highest and lowest utility score.

Below is Escalent's list of 2019 Most Trusted Utility Brands. Congratulations to the 32 utilities that have shown industry leadership and scored highest on the study's overall Brand Trust index among their peers.

2019 Most Trusted Brands		
Combination Utilities	**Electric Utilities**	**Natural Gas Utilities**
DTE Energy	OUC	TECO Peoples Gas
Black Hills Energy – Midwest	Georgia Power	Piedmont Natural Gas
Con Edison	SMUD	NW Natural
PECO	Southwestern Electric Power Company	CenterPoint Energy – South
CPS Energy	Florida Power & Light	Texas Gas Service
Puget Sound Energy	Salt River Project	PSNC Energy
Avista	PPL Electric Utilities	UGI Utilities
	AEP Ohio	Peoples Gas
	Dayton Power & Light	New Jersey Natural Gas
	OPPD	SEMCO Energy Gas Company
		Washington Gas
		National Fuel Gas
		Citizens Energy
		Peoples
		CenterPoint Energy – Midwest

Following charts reflect regional peer benchmark Brand Trust scores among the 140 utilities surveyed. These scores reflect the amount of trust customers have with each utility.

East Region Utilities Brand Trust Performance		
Combination Service (Electric and Natural Gas)	**Electric Service**	**Natural Gas Service**

Con Edison	720	PPL Electric Utilities	708	UGI Utilities	727
PECO	705	West Penn Power	683	New Jersey Natural Gas	723
PSE&G	698	Atlantic City Electric	680	Washington Gas	717
Delmarva Power	695	Duquesne Light Company	677	National Fuel Gas	716
BGE	675	Pepco	673	Peoples	709
National Grid	675	Penelec	669	Philadelphia Gas Works	706
RG&E	663	Penn Power	664	South Jersey Gas Company	700
Eversource	652	Jersey Central Power & Light	656	Elizabethtown Gas	692
NYSEG	629	Appalachian Power	651	Columbia Gas–East	670
		Monongahela Power	647		
		PSEG Long Island	647		
		Met-Ed	641		
		Potomac Edison	627		
		Central Maine Power	548		
Scoring based upon 1,000-point maximum scale					

Midwest Region Utilities Brand Trust Performance					
Combination Service (Electric and Natural Gas)		Electric Service		Natural Gas Service	
DTE Energy	746	AEP Ohio	706	Peoples Gas	725
Black Hills Energy–Midwest	739	Dayton Power & Light	704	SEMCO Energy Gas Company	717
Xcel Energy–Midwest	718	OPPD	695	Citizens Energy	711
MidAmerican Energy	718	ComEd	687	CenterPoint Energy–Midwest	705
Ameren Illinois	714	Toledo Edison	679	Columbia Gas of Ohio	700
Duke Energy Midwest	714	Ohio Edison	676	Nicor Gas	699
We Energies	697	Indiana Michigan Power	671	Atmos Energy – Midwest	690
Consumers Energy	690	The Illuminating Company	665	Kansas Gas Service	687
NIPSCO	690	Indianapolis Power & Light	659	Dominion Energy Ohio	685
Wisconsin Public Service	685	Westar Energy	654	Spire Missouri–East	671
Vectren	680	KCP&L	649	Spire Missouri–West	642

Alliant Energy	661	Ameren Missouri	629		
Scoring based upon 1,000-point maximum scale					

South Region Utilities Brand Trust Performance					
Combination Service (Electric and Natural Gas)		**Electric Service**		**Natural Gas Service**	
CPS Energy	703	OUC	745	TECO Peoples Gas	762
Louisville Gas & Electric	667	Georgia Power	729	Piedmont Natural Gas	745
SCE&G	624	Florida Power & Light	727	CenterPoint Energy–South	739
MLGW	614	Southwestern Electric Power Company	727	Texas Gas Service	735
		Alabama Power	720	PSNC Energy	728
		Gulf Power	716	Columbia Gas–South	723
		Nashville Electric Service	715	Spire Mississippi	721
		Entergy Texas	711	Oklahoma Natural Gas	715
		JEA	705	Atmos Energy–South	712
		Entergy Mississippi	703	Virginia Natural Gas	711
		Xcel Energy–South	703	Florida City Gas Company	704
		Kentucky Utilities	702	Spire South	700
		OG&E	699	Chattanooga Gas Company	688
		Mississippi Power	695	Spire Gulf Coast	610
		TECO Tampa Electric	690		
		Entergy Louisiana	689		
		Public Service Company of Oklahoma	687		
		Dominion Energy Virginia	677		
		Entergy Arkansas	676		
		Duke Energy Progress	674		
		Duke Energy Carolinas	673		
		El Paso Electric	657		

		Austin Energy	650		
		Duke Energy Florida	648		
		Entergy New Orleans	642		
		Kentucky Power	609		
Scoring based upon 1,000-point maximum scale					

West Region Utilities Brand Trust Performance					
Combination Service (Electric and Natural Gas)		**Electric Service**		**Natural Gas Service**	
Puget Sound Energy	700	SMUD	728	NW Natural	744
Avista	694	Salt River Project	716	Cascade Natural Gas	714
Xcel Energy–West	685	Tucson Electric Power	708	Southwest Gas	713
NorthWestern Energy	641	Idaho Power	707	Dominion Energy–West	700
PG&E	641	Portland General Electric	704	Intermountain Gas Company	693
SDG&E	640	Southern California Edison	688	SoCalGas	691
Black Hills Energy–West	613	Rocky Mountain Power	678	New Mexico Gas Company	671
		Pacific Power	673		
		NV Energy	671		
		Seattle City Light	668		
		PNM	647		
		APS	639		
		Los Angeles Department of Water & Power	635		
Scoring based upon 1,000-point maximum scale					

About Utility Trusted Brand & Customer Engagement™: Residential

Escalent conducted surveys among 62,122 residential electric, natural gas and combination utility customers of the 140 largest US utility companies (based on residential customer counts). The sample design uses a combination of quotas and weighting based on US census data to ensure a demographically balanced sample of each evaluated utility's customers based on age, gender, income, race and ethnicity. Utilities within the same region and of the same type (e.g., electric-only providers) are given equal weight in order to balance the influence of each utility's customers on survey results. Escalent will supply the exact wording of any survey question upon request.

Click below for more on the full report.

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News

Trust in Utilities Reaches All-Time High During COVID-19

JUNE 23, 2020

44 Utilities named Most Trusted Brands

Customer trust in utilities has hit a historic high due to the industry's effective response to the COVID-19 pandemic. This year, the Cogent Syndicated Brand Trust Index posts a record high score of 696 (on a 1,000-point scale), with 44 utilities being named the 2020 Most Trusted Brands, having scored highest on the Brand Trust Index among the 140 utilities surveyed. These and other findings are from the 2020 Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Residential study from Escalent, a top human behavior and analytics firm.

The Brand Trust Index is a composite score of utility performance on customer focus, community support, communications effectiveness, reliable quality, environmental dedication and reputation. Although customer trust in utilities had been increasing before the pandemic, the industry's effective response to COVID-19 accelerated this trend. Customers rate the industry a very high 7.20 (on a 10-point scale) when asked how responsibly their utility responded to the COVID-19 crisis. The more responsive a utility was to COVID-19, the more trust customers place in them. And half of utility customers "strongly agree" their utility responded well to the pandemic.

"It is clear from our research the utility industry has done a fantastic job supporting customers through the pandemic. This has won utilities the trust and goodwill of their customers," said Chris Oberle, senior vice president at Escalent. "The utility industry is used to handling crises and quickly provided customer support. Awareness of utility COVID-19 efforts was supported by higher communications recall, the high quality of customer service interactions, and providing more value-added recommendations during service."

Escalent would like to congratulate the 2020 Most Trusted Utility Brands that have supported their customers through an unprecedented crisis and have built goodwill and leadership in their communities.

Cogent Syndicated 2020 Most Trusted Utility Brands	
AEP Ohio	NIPSCO
Ameren Illinois	NW Natural

BGE	OPPD
Black Hills Energy – Midwest	OUC
Cascade Natural Gas	Peoples Gas
CenterPoint Energy – South	Pepco
Columbia Gas – South	Philadelphia Gas Works
Columbia Gas of Ohio	Piedmont Natural Gas
CPS Energy	PPL Electric Utilities
Dayton Power & Light	PSE&G
Delmarva Power	Puget Sound Energy
DTE Energy	RG&E
Duke Energy Midwest	Salt River Project
Duquesne Light Company	Seattle City Light
Elizabethtown Gas	TECO Peoples Gas
Florida City Gas Company	Texas Gas Service
Florida Power & Light	UGI Utilities
Idaho Power	Washington Gas
Kentucky Utilities	Wisconsin Public Service
MidAmerican Energy	Xcel Energy – Midwest
National Fuel Gas	Xcel Energy – South
New Jersey Natural Gas	Xcel Energy – West

Following charts reflect regional peer benchmark Brand Trust scores among the 140 utilities surveyed. These scores reflect the amount of trust customers have with each utility.

East Region Utilities Brand Trust Performance					
Combination Service (Electric and Natural Gas)		Electric Service		Natural Gas Service	
PSE&G	717	PPL Electric Utilities	719	Washington Gas	738
RG&E	712	Duquesne Light Company	705	Philadelphia Gas Works	728
Delmarva Power	711	Pepco	700	Elizabethtown Gas	727
BGE	698	Penelec	698	New Jersey Natural Gas	726
Con Edison	693	Green Mountain Power	693	UGI Utilities	725
PECO	691	Atlantic City Electric	684	National Fuel Gas	724

National Grid	683	Penn Power	677	South Jersey Gas Company	703
Eversource	681	West Penn Power	674	Peoples	689
NYSEG	678	PSEG Long Island	671	Columbia Gas – East	659
		Met-Ed	669		
		Appalachian Power	659		
		Mon Power	658		
		Potomac Edison	647		
		Jersey Central Power & Light	644		
		Central Maine Power	556		
Scoring based upon 1,000-point maximum scale					

Midwest Region Utilities Brand Trust Performance					
Combination Service (Electric and Natural Gas)		**Electric Service**		**Natural Gas Service**	
Black Hills Energy – Midwest	718	AEP Ohio	724	Columbia Gas of Ohio	747
MidAmerican Energy	714	Dayton Power & Light	718	Peoples Gas	733
DTE Energy	713	OPPD	714	CenterPoint Energy – Midwest	721
Xcel Energy – Midwest	707	ComEd	701	Nicor Gas	700
Ameren Illinois	705	Ameren Missouri	698	Dominion Energy Ohio	698
Wisconsin Public Service	704	Toledo Edison	689	Spire Missouri – East	689
NIPSCO	702	Ohio Edison	672	Kansas Gas Service	684
Duke Energy Midwest	699	Indianapolis Power & Light	662	Citizens Energy	671
Consumers Energy	687	Evergy	659	Atmos Energy – Midwest	670
We Energies	678	Indiana Michigan Power	659	Spire Missouri – West	666
Alliant Energy	671	The Illuminating Company	655		
Vectren	655				
Scoring based upon 1,000-point maximum scale					

South Region Utilities Brand Trust Performance					
Combination Service (Electric and Natural Gas)		**Electric Service**		**Natural Gas Service**	
CPS Energy	715	OUC	752	TECO Peoples Gas	784
Louisville Gas & Electric	689	Kentucky Utilities	751	Columbia Gas – South	757
Dominion Energy South Carolina	659	Xcel Energy – South	734	Piedmont Natural Gas	750
MLGW	633	Florida Power & Light	732	Florida City Gas Company	739
		Nashville Electric Service	717	Texas Gas Service	735
		Georgia Power	716	CenterPoint Energy – South	734
		TECO Tampa Electric	710	Atmos Energy – South	728
		Public Service Company of Oklahoma	708	Oklahoma Natural Gas	726
		OG&E	707	Virginia Natural Gas	725
		Southwestern Electric Power Company	707	Chattanooga Gas Company	712
		Entergy Mississippi	700	Spire South	708
		Mississippi Power	699	Dominion Energy North Carolina	696
		JEA	697	Spire Mississippi	674
		Entergy Louisiana	696	Spire Gulf Coast	636
		Dominion Energy Virginia	694		
		Alabama Power	694		
		Entergy Arkansas	687		
		Entergy Texas	685		
		Gulf Power	681		
		Duke Energy Carolinas	680		
		Duke Energy Florida	675		
		El Paso Electric	674		
		Austin Energy	671		
		Duke Energy Progress	662		
		Entergy New Orleans	648		
		Kentucky Power	621		
Scoring based upon 1,000-point maximum scale					

West Region Utilities Brand Trust Performance					
Combination Service (Electric and Natural Gas)		Electric Service		Natural Gas Service	
Xcel Energy – West	719	Idaho Power	727	NW Natural	766
Puget Sound Energy	699	Seattle City Light	723	Cascade Natural Gas	748
Avista	692	Salt River Project	721	SoCalGas	732
NorthWestern Energy	689	SMUD	699	Intermountain Gas Company	730
SDG&E	685	Portland General Electric	693	Southwest Gas	725
Black Hills Energy – West	604	Tucson Electric Power	685	Dominion Energy – West	708
PG&E	579	Southern California Edison	682	New Mexico Gas Company	680
		NV Energy	681		
		Pacific Power	680		
		Rocky Mountain Power	678		
		PNM	665		
		Los Angeles Department of Water & Power	658		
		APS	634		
Scoring based upon 1,000-point maximum scale					

About Utility Trusted Brand & Customer Engagement™: Residential

Escalent conducted surveys among 70,438 residential electric, natural gas and combination utility customers of the 140 largest US utility companies (based on residential customer counts). The sample design uses a combination of quotas and weighting based on US census data to ensure a demographically balanced sample of each evaluated utility's customers based on age, gender, income, race and ethnicity. Utilities within the same region and of the same type (e.g., electric-only providers) are given equal weight to balance the influence of each utility's customers on survey results. Escalent will supply the exact wording of any survey question upon request.

Click below for more information on the study.

News

Brand Trust Spikes as Utilities Spend More on Communication

JUNE 24, 2021

Escalent Names 38 Utilities 2021 Most Trusted Brands

Customer trust in utility companies spiked to the highest score ever on the Escalent utility Brand Trust Index (706 on a 1,000-point scale) due to spending roughly 16% more to communicate about product options, environmental efforts, and how they partnered with customers on shared priorities during the pandemic. The communications were well received by utility customers, as the Communications Effectiveness metric posted the highest average score (738) among the six factors that compose Brand Trust. This information is part of the 2021 Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Residential study from Escalent, a top human behavior and analytics advisory firm.

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reputation. Among these six factors, Customer Focus has increased the most during the year (13 points) followed by Company Reputation (12 points) and Community Support (11 points).

"Starting active conversations with customers on how their utility can partner with and support them throughout the challenges faced this past year has strongly positioned utilities as trusted energy advisers and great corporate citizens," said Chris Oberle, senior vice president at Escalent. "Our research shows that nearly all utilities provide great service levels, but an elite group has been able to build trusted brands that empower customers with valuable offerings and value-added information. The most trusted utility brands include utilities that are making a positive impact on their customers, communities and financials."

Key findings from the study include:

- Customers with high brand trust use an average of nine enhanced utility offerings compared with only four for customers with low trust levels.
- Two in three (62%) of those with high brand trust use utility digital options.
- High brand trust increases customer acceptance of utility rate changes by 23%.
- Customer trust is built over time, as new customers give lower Brand Trust scores than those who've been customers longer.

- The utility industry should focus on low-income customers ($25K or less annual household income), as they post lower Brand Trust scores than customers with higher income levels.
- High brand trust minimizes the negative-perception impacts from outage, safety and other critical events, while increasing customer advocacy and loyalty.

Escalent congratulates the 2021 Most Trusted Brands among utilities. These 38 utilities have developed industry-leading customer trust levels.

Cogent Syndicated 2021 Most Trusted Utility Brands		
Avista	Intermountain Gas Company	PSE&G
Cascade Natural Gas	Kentucky Utilities	RG&E
CenterPoint Energy – Midwest	New Jersey Natural Gas	Rocky Mountain Power
Colorado Springs Utilities	Nicor Gas	Salt River Project
Columbia Gas – South	NW Natural	SMUD
Columbia Gas of Ohio	Oklahoma Natural Gas	TECO Peoples Gas
CPS Energy	OPPD	Toledo Edison
DTE Energy	OUC	Tucson Electric Power
Elizabethtown Gas	PECO	UGI Utilities
Florida Power & Light	Peoples Gas	Washington Gas
Georgia Power	Pepco	Wisconsin Public Service
Green Mountain Power	Portland General Electric	Xcel Energy – West
Idaho Power	PPL Electric Utilities	

The following tables reflect regional peer benchmark Brand Trust scores among the 140 utilities surveyed. These scores reflect the amount of trust customers have with each utility.

East Region Utilities Brand Trust Performance		
Utility brand name	Service provided	Brand trust score
PECO	Combination	733
PSE&G	Combination	726
RG&E	Combination	716
Con Edison	Combination	708
Delmarva Power	Combination	708
National Grid	Combination	706
BGE	Combination	685
NYSEG	Combination	653

Eversource Energy	Combination	636
Pepco	Electric	742
Green Mountain Power	Electric	741
PPL Electric Utilities	Electric	736
Penn Power	Electric	708
Duquesne Light	Electric	700
Met-Ed	Electric	696
Penelec	Electric	690
West Penn Power	Electric	687
Potomac Edison	Electric	683
Atlantic City Electric	Electric	679
Appalachian Power	Electric	670
Mon Power	Electric	663
Jersey Central Power & Light	Electric	627
PSEG Long Island	Electric	625
Central Maine Power	Electric	623
Elizabethtown Gas	Natural Gas	751
Washington Gas	Natural Gas	749
UGI Utilities	Natural Gas	742
New Jersey Natural Gas	Natural Gas	738
National Fuel Gas	Natural Gas	723
Peoples	Natural Gas	722
South Jersey Gas Company	Natural Gas	716
Philadelphia Gas Works	Natural Gas	714

Midwest Region Utilities Brand Trust Performance		
Utility brand name	**Service provided**	**Brand trust score**
DTE Energy	Combination	758
Wisconsin Public Service	Combination	755
Black Hills Energy – Midwest	Combination	736
Montana Dakota Utilities	Combination	736
Xcel Energy – Midwest	Combination	730
Ameren Illinois	Combination	726
Consumers Energy	Combination	722
MidAmerican Energy	Combination	719

Duke Energy Midwest	Combination	718
Alliant Energy	Combination	717
NIPSCO	Combination	686
We Energies	Combination	674
Vectren	Combination	666
Toledo Edison	Electric	713
OPPD	Electric	709
The Illuminating Company	Electric	693
AEP Ohio	Electric	692
Ohio Edison	Electric	692
ComEd	Electric	690
AES Ohio	Electric	689
Ameren Missouri	Electric	684
AES Indiana	Electric	680
Indiana Michigan Power	Electric	680
Evergy	Electric	671
Columbia Gas of Ohio	Natural Gas	737
Peoples Gas	Natural Gas	724
Nicor Gas	Natural Gas	723
CenterPoint Energy – Midwest	Natural Gas	720
Spire Missouri – East	Natural Gas	715
Dominion Energy Ohio	Natural Gas	712
Atmos Energy – Midwest	Natural Gas	708
Kansas Gas Service	Natural Gas	705
Citizens Energy	Natural Gas	697
Spire Missouri – West	Natural Gas	694

South Region Utilities Brand Trust Performance		
Utility brand name	**Service provided**	**Brand trust score**
CPS Energy	Combination	714
Louisville Gas & Electric	Combination	688
Dominion Energy South Carolina	Combination	682
MLGW	Combination	644
Kentucky Utilities	Electric	745

OUC	Electric	742
Florida Power & Light	Electric	739
Georgia Power	Electric	733
Entergy Texas	Electric	723
Entergy Mississippi	Electric	721
Entergy Arkansas	Electric	716
TECO Tampa Electric	Electric	716
Alabama Power	Electric	713
Dominion Energy Virginia	Electric	711
Entergy Louisiana	Electric	711
Mississippi Power	Electric	710
Nashville Electric Service	Electric	710
OG&E	Electric	710
Southwest Electric Power Company	Electric	708
Xcel Energy – South	Electric	706
Public Service Company of Oklahoma	Electric	703
El Paso Electric	Electric	701
Duke Energy Florida	Electric	697
Duke Energy Carolinas	Electric	695
Gulf Power	Electric	692
JEA	Electric	684
Austin Energy	Electric	682
Duke Energy Progress	Electric	664
Entergy New Orleans	Electric	662
Kentucky Power	Electric	656
Columbia Gas – South	Natural Gas	768
TECO Peoples Gas	Natural Gas	760
Oklahoma Natural Gas	Natural Gas	746
Piedmont Natural Gas	Natural Gas	740
Florida City Gas Company	Natural Gas	739
CenterPoint Energy – South	Natural Gas	733
Virginia Natural Gas	Natural Gas	729
Dominion Energy North Carolina	Natural Gas	727
Spire Alabama	Natural Gas	724
Texas Gas Service	Natural Gas	724

Atmos Energy – South	Natural Gas	721
Spire Mississippi	Natural Gas	716
Chattanooga Gas Company	Natural Gas	708
Spire Gulf Coast	Natural Gas	656

West Region Utilities Brand Trust Performance		
Utility brand name	**Service provided**	**Brand trust score**
Xcel Energy – West	Combination	734
Avista	Combination	726
Colorado Springs Utilities	Combination	721
NorthWestern Energy	Combination	705
Puget Sound Energy	Combination	697
SDG&E	Combination	688
Black Hills Energy – West	Combination	658
PG&E	Combination	626
Salt River Project	Electric	740
Idaho Power	Electric	736
Portland General Electric	Electric	730
SMUD	Electric	726
Tucson Electric Power	Electric	726
Rocky Mountain Power	Electric	720
Seattle City Light	Electric	717
Southern California Edison	Electric	701
Pacific Power	Electric	694
NV Energy	Electric	676
Los Angeles Department of Water & Power	Electric	666
PNM	Electric	665
APS	Electric	641
Cascade Natural Gas	Natural Gas	760
Intermountain Gas Company	Natural Gas	759
NW Natural	Natural Gas	751
SoCalGas	Natural Gas	735
Dominion Energy West	Natural Gas	714
Southwest Gas	Natural Gas	704

New Mexico Gas Company	Natural Gas	702

About Utility Trusted Brand & Customer Engagement™: Residential

Escalent conducted surveys among 76,656 residential electric, natural gas and combination utility customers of the 140 largest US utility companies (based on residential customer counts). The sample design uses a combination of quotas and weighting based on US census data to ensure a demographically balanced sample of each evaluated utility's customers based on age, gender, income, race and ethnicity. Utilities within the same region and of the same type (e.g., electric-only providers) are given equal weight to balance the influence of each utility's customers on survey results. The Brand Trust index score is a composite based upon consumer ratings across six factors. Escalent will supply the exact wording of any survey question upon request.

Click below to learn more about the full study.

SHOW ME MORE

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BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	**Docket No. R-2021-3030218**
UGI Utilities, Inc. – Gas Division	**)**	

DIRECT TESTIMONY OF

DANTE MUGRACE

ON BEHALF OF THE

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE

April 20, 2022

<u>HIGHLY CONFIDENTIAL VERSION</u>

TABLE OF CONTENTS

I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a Senior Consultant with the Economic and Management Consulting Firm of PCMG and Associates, LLC. (PCMG). In my capacity as a Senior Consultant, I am responsible for evaluating and examining rate and rate related proceedings before various governmental entities, preparing expert testimony, recommending revenue requirements, as well as offering opinions on economic policy, policy issues and methodologies used to set a value on a utility's rate base and cost of service components of revenue requirement.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. PCMG is an association of experts in utility regulation and policy, economics, accounting and finance. PCMG's members have over 75 years of collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water and wastewater utilities that operate under local, state and federal jurisdictions. PCMG focuses on areas regarding revenue requirement, cost of service, rate design, cost of capital and rate of return. Prior to my association with PCMG, I was employed as a Senior Consultant with the consulting firm of Snavely King Majoros and Associates (SKM) from 2013 to 2015, in the same capacity as PCMG. Prior to SKM, I was employed by the New Jersey Board of Public Utilities (NJBPU) from 1983 to my retirement in 2011. During my tenure at the NJBPU, I held various Accounting, Rate Analyst, Supervisory and Management Positions. My last position was Bureau Chief of Rates in the Agency's Water Division (Bureau Chief of Rates). I held this position for nearly 10 years. My resume is attached as Appendix A.

Q. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE SETTING PROCEEDINGS AND OTHER UTILITY MATTERS?

A. In my capacity as Bureau Chief of Rates at NJBPU, I was responsible for overseeing the rate process regarding administrative, financial, and managerial functions of the Rates

Bureau. My primary duties were to ensure that the jurisdictional utilities had sufficient revenues to cover their operating expenses, the ability to earn a reasonable rate of return on plant investments, and to ensure that the provision of safe, adequate and proper service at reasonable rates was met. During my time at the NJBPU, I was involved in hundreds of rate and rate related proceedings. In my capacity as a Senior Consultant previously with SKM and now with PCMG, I have been and am currently involved in rate and rate related proceedings before the Commissions in the Commonwealth of Massachusetts and Pennsylvania, and the States of Maine, Maryland, New Jersey, New York, North Dakota, and Ohio. I was involved in the Generic Proceedings to Establish Parameters for the Next Generation Performance Based Rate Plans before the Alberta Utilities Commission. I was involved in transmission formula rate plans before the Federal Energy Regulatory Commission (FERC) regarding the PECO Energy Company on behalf of the Pennsylvania OCA and the Rockland Electric Company on behalf of the NJ Division of Rate Counsel.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Master of Business Administration (MBA) degree with a concentration in Strategic Management from Pace University-Lubin School of Business in New York, New York. I hold a Master of Public Administration (MPA) degree from Kean University in Union, New Jersey. I hold a Bachelor of Science (BS) degree in Accounting from Saint Peter's University in Jersey City, New Jersey.

II. PURPOSE OF TESTIMONY

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Pennsylvania Office of the Consumer Advocate (OCA).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to calculate and to make a recommendation regarding the UGI Utilities, Inc. – Gas Division's (UGI or Company) base rate case proceeding, that was filed with the Pennsylvania Public Utility Commission (PAPUC or Commission) on

January 28, 2022.[1] My recommendation includes the setting of the Company's Rate Base Valuation, and Pro Forma Operating Income at Present Rates for the Fully Projected Future Test Year Period Ending September 30, 2023. The Company requested an overall increase in rates for its gas distribution service of approximately $82.7 million or 7.80% above current operating revenues of approximately $1.063 billion. The Company provides Gas Distribution service to about 672,000 customers located in the counties of Berks, Bucks, Carbon, Chester, Cumberland, Dauphin, Franklin, Lancaster, Lebanon, Lehigh, Luzerne, Monroe, Montgomery, Northampton, Schuylkill and York. The Company's last base rate case proceeding was approved by the Commission on August 29, 2020 in Docket No. R-2019-3015162. Included in my recommended position on Rate Base Valuation and Operating Income, I am also incorporating the recommendations of OCA witness Mr. David Garrett with respect to the overall rate of return, OCA witness Mr. Jerome Mierzwa on any rate design adjustments, and OCA witness Mr. Roger Colton on Universal Service adjustments.

III. REVENUE REQUIREMENT ISSUES

A. SUMMARY

Q. WHAT REVENUE DEFICIENCIES OR ADJUSTMENTS ARE YOU RECOMMENDING?

A. Based upon the use of the Company's proposed fully projected future test year ending September 30, 2023, I have the following recommendations:

- My recommended Rate Base balance is $3,087,298,717, which is $81,724,283 lower than the Company's proposed Rate Base balance of $3,169,023,000.
- My overall Rate of Return based upon OCA witness Garrett's recommendation is 6.24%, which includes a Common Equity component of 8.50% and a Common Equity Ratio of 50.00%.

[1] UGI Utilities, Inc. – Gas Division is a wholly owned subsidiary of UGI Corporation. UGI Corporation has two operating divisions, the Gas Division and the Electric Division, both which are regulated by the PAPUC.

- My recommended Operating Revenue at Present Rates is computed at $1,063,137,667, which is $413,667 higher than the Company's Present Rate Revenue of $1,062,724,000.[2]
- My recommended total Operating Expenses at Present Rates is $795,924,424, which is $32,576,576 lower than the Company's proposed Operating Expenses at Present Rates of $828,501,000.
- My recommended Federal Income Tax at Present Rates is $37,748,730.
- My recommended State Income Tax at Present Rates is $9,769,753.
- Overall, I recommend a revenue requirement decrease of $38,673,989, which is $121,416,259 lower than the Company's proposed revenue requirement increase of $82,742,000.

Q. WHAT EFFECT DOES MR. GARRETT'S REMOVAL OF MR. MOUL'S MANAGEMENT PERFORMANCE PREMIUM OF 0.20% HAVE ON THE COMPANY'S REVENUE REQUIREMENT?

A. The effect of removing the 0.20% Management Performance Premium from the Company's Cost of Equity would be to reduce the Company's filed 11.20% Equity Cost Rate to 11.00%. Incorporating this into the overall rate of return would result in an ROR of 7.85% instead of the Company's proposed 7.96%. The revenue requirement impact would be a reduction of about $4.984 million. (Rate Base of $3.169 billion times the rate of return of 7.85% equals $248.768 million, or a reduction from the Company's proposed income requirement of $252.254 million of $3.385 million multiplied by the gross revenue factor of 1.429864 equals $4.984 million.

Q. WHAT EFFECT DOES MR. GARRETT'S REMOVAL OF MR. MOUL'S LEVERAGE ADJUSTMENT OF .95% HAVE ON THE COMPANY'S REVENUE REQUIREMENT?

A. The effect of removing the .95% Leverage Adjustment from the Company's filed 11.20% Equity Cost Rate would equal an Equity Cost Rate of 10.25%. Incorporating this into the overall rate of return would result in a ROR of 7.44% instead of the Company's proposed 7.96%. The revenue requirement impact would be a reduction of

[2] Any differences between Company Operating Revenues at Present Rates in its filing and my Schedules are due to rounding.

about $23.562 million. (Rate Base of $3.169 billion times the rate of return of 7.44% equals $235.775 million, which is a reduction from the Company's proposed income requirement of $252.254 million of $16.478 million multiplied by the gross revenue factor of 1.429864 equals $23.562 million.)

Q. WHAT EFFECT DOES MR. GARRETT'S CAPITAL STRUCTURE HAVE ON THE COMPANY'S OVERALL REVENUE REQUIREMENT INCREASE?

A. Based upon Mr. Garrett's overall recommended capital structure, the return requirement proposed by the Company would go down from $252.254 million to $197.747 million, a decrease of $54.507 million. Including the Revenue Conversion Factor of 1.429864 would calculate to a $77.937 million revenue requirement decrease from the Company's proposed revenue requirement of $82.742 million, or an increase of $4.804 million.

Q. WHAT RATE BASE COMPONENTS ARE YOU ACCEPTING IN THIS PROCEEDING?

A. I am accepting the Company's balances related to Gas Inventory, Customer Deposits, and Materials and Supplies, which are shown on my Schedule DM-3.

B. RATE BASE (Measures of Value)

1. <u>GAS Plant in Service (GPIS)</u>

Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS GAS PLANT IN SERVICE?

A. The Company has proposed a GPIS balance of $5,042,025,000[3] for the fully projected future test year for the twelve months ending September 30, 2023. (Company Schedule C-1 and C-2). Company witness Ms. Tracy Hazenstab developed this balance by starting with the Historical Test Year (HTY) period ending September 30, 2021 and included pro forma adjustments through the Future Test Year (FTY) period September 30, 2022. To that balance, the Company included pro forma adjustments through the Fully Projected Future Test Year (FPFTY) period ending September 30, 2023. The FPFTY information

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[3] Differences between the Company's balance and my balance are due to rounding.

was derived from the Company's operating and capital budgets for the 12-month period ending September 30, 2023. (Statement No. 2 at 4).

Included in that balance are plant additions that the Company expects to place in service during the FPFTY period ending September 30, 2023, of which the amount of $398,404,000 are for plant additions through the FTY ending September 30, 2022, and an additional $476,632,000 through the FPFTY period ending September 30, 2023. The total proposed plant additions sum up to $875,036,000. (Company Schedule C-2).

Q. HOW DID THE COMPANY DEVELOP ITS CAPITAL INVESTMENT TO PRODUCE THE TOTAL PROPOSED PLANT ADDITIONS OF $ 875,036,000 AS OF SEPTEMBER 30, 2023?

A. Company witness Ms. Vicky Schappell stated that the categories of plant additions are related to (1) replacement and betterment infrastructure; (2) new business; (3) information technology; (4) other capital spending and; (5) removal and salvage. (Statement No. 5 at 3). Ms. Schappell stated that the determination of projects that are included in the capital budgets are based upon a risk-based prioritization process. This process is more fully explained in Ms. Schappell's testimony Statement No. 3 at page 3.[4]

Q. HOW HAVE THE COMPANY'S ACTUAL CAPITAL ADDITIONS COMPARED TO BUDGETED CAPITAL ADDITIONS IN THE PAST?

A. According to Ms. Schappell, over the past five years, the Company's total budgeted capital additions produced a variance of $34,081,000 which equates to 98% of the Company's plant additions of its budget, or a 2% variance between budgeted and actual plant placed in service. (Statement No. 5 at 8).

Q. WHAT COSTS ARE INCLUDED IN THE COMPANY'S GPIS BALANCE RELATED TO THE COMMISSION APPROVED LONG-TERM INFRASTRUCTURE IMPROVEMENT PLAN (LTIIP)?

A. As noted in response to OCA-III-2, the Company has included approximately $266,908,000 of LTIIP expenditures[5] through the FTY ending September 30, 2022, and an additional $275,002,000 through the FPFTY ending September 30, 2023. Company

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[4] The Company identifies Major Projects as projects greater than $15 million which require Board approval. OCA-Set III-2.

[5] Included in this balance are plant additions related to the Company's DIMP and TIMP categories. OCA-Set III-2.

witness Mr. Angstadt stated that through the LTIIP, the Company has been identifying and repairing, improving or replacing its distribution infrastructure on an accelerated basis, which has resulted in removing more than 463 miles of mains over the seven-year period (2014-2020) including cast iron mains and total bare steel/wrought iron mains. Through December 31, 2021, the Company has removed 76 miles of mains. (Statement No. 9 at 8).

Q. WHAT LEVEL OF CAPITAL COSTS HAS THE COMPANY PROJECTED TO BE PLACED IN SERVICE RELATED TO ITS REPLACEMENT AND BETTERMENT PLANT ADDITIONS?

A. Mr. Angstadt stated that for fiscal year 2022 the Company has budgeted $281,400,000 of plant additions, and for fiscal year 2023 the Company has budgeted $305,800,000 of plant additions. (Statement No. 9 at 11).

Q. DID THE COMPANY PROPOSE ANY ADJUSTMENTS SUBSEQUENT TO THE FILING OF THIS RATE CASE WITH RESPECT TO THE COMPANY'S PROPOSED GPIS BALANCE OF $5,042,025,000?

A. In response to OCA-X-2, I asked the Company whether any costs have changed from the as filed petition with respect to capital additions in the FTY and in the FPFTY period. The Company responded that at this point there have been no changes in the forecasted FTY plant additions and FPFTY plant additions. The Company does not anticipate a material variance to the FTY and FPFTY capital additions. To the extent operating conditions and circumstances change, such as the need to reprioritize projects or adjust anticipated in-service dates and potential increase in contractor costs impact the Company's projects for the FTY and the FPFTY, it will update its projections as needed.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE COMPANY'S PROJECTED TIMELINE OF THESE IN-SERVICE DATES?

A. Yes. In response to I&E-RB-4-D, the Company provided its construction budget by plant account for the Future and the Fully projected test years, as well as all projects to be completed in the Future Test Year and the Fully projected test year by plant account and their estimated completion dates. The confidential response shows that for a number of projects the estimated completion date will be beyond the FPFTY period ending December 31, 2023. These projects are as follows: **(Begin Confidential)**

Budget Group	Description	Completion Date	FY 2022 Budget
• 09O	16^{th} & Battery PO02	Sept. 2024	$500,156
• 09O	Penn & Cherry 30358	Sept. 2024	$49,871
• 09O	Knox Ave. Station	Feb. 2024	$18,134
• 12O	Hobbie TL Replace.	Dec. 2025	$1,002,045
• 12O	Lessport Phase 2	Sept. 2024	$179,821
• 12O	Hazle Township Blvd.	June 2024	$119,632
• 12O	Hill Rd. High Press. Exp.	Sept. 2024	$836
• 12O	County Welfare Rd.	July 2024	$302
• 12O	3000 BLK Rich Hill Rd	March 2024	$26
• 12O	Penn Cherry Sta. Reloc	Sept. 2024	$1
• 145	UNITE EAM	Sept. 2025	$25,320,125
• 41M	Primrose Ally Main	Jan. 2024	$394,547
• 45M	Lehigh River Cross.	May 2024	$199,693
Total FY 2022 Budget Projects			**$27,785,189**
			FY 2023 Budget
• 09O	16^{th} & Battery PO02	Sept. 2024	$4,113
• 09O	Penn & Cherry 30358	Sept. 2024	$410
• 09O	Knox Ave. Station	Feb. 2024	$149
• 12O	5100 BLK Main White.	Sept. 2024	$1,508,721
• 12O	Hobbie TL Replace.	Dec. 2025	$8,245
• 12O	Lessport Phase 2	Sept. 2024	$2,983
• 12O	Hazle Township Blvd.	June 2024	$997
• 12O	Hill Road High Press.	Sept. 2024	$844
• 12O	County Welfare Rd.	July 2024	$304
• 12O	3000 BLK Rich Hill Rd.	Mar. 2024	$26
• 145	UNITE ADC	Sept. 2025	$8,425,085
• 145	UNITE EAM	Sept. 2025	$41,640,121
• 41M	Primrose Alley Main	Jan. 2024	$3,009

- 44M Southern Hymil Line Sept. 2024 $6,301,771

Total FY 2023 Budget Projects **$57,896,778**

Total FY 2022 and FY 2023 Budget Projects **$85,681,967**

Q. WHAT IS YOUR TOTAL RECOMMENDED ADJUSTMENT TO THE COMPANY'S GPIS BALANCE ?

A. Based upon the above, I am recommending that these FY 2022 and FY 2023 budget projects be removed from the Company's GPIS balance as the estimated completion dates are beyond the Company's FPFTY period ending December 31, 2023. These projects are listed as Gas Division Projects. Out of the total budgeted project balance of $85,681,967, $10,296,636 are accounted for under the Company's Distribution Plant and $75,385,331 are accounted for under General Plant – UNITE **(End Confidential).** My adjustments are shown on my Schedule DM-5.

2. Accumulated Depreciation

Q. WHAT HAS THE COMPANY CALCULATED WITH RESPECT TO ITS ACCUMULATED DEPRECIATION?

A. The Company computed an Accumulated Depreciation balance in the amount of $1,318,560,000 as shown on Company Schedule C-3. Company witness Ms. Vivian Ressler stated that the Company started with an Accumulated Depreciation balance as of September 30, 2021 and added budgeted levels of depreciation expense for the FTY to produce an Accumulated Depreciation balance of $1,229,399,000 (Company Schedule C-3). For the FPFTY period, the Company calculated the associated plant retirements and a provision for net salvage to arrive at the Accumulated Depreciation balance of $1,318,560,000. The amount of the net salvage value was calculated using a five-year amortization schedule in accordance with Commission precedent. (Statement No. 3 at 7-8).

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's calculation with respect to the development of the Accumulated Depreciation balance. My adjustment is related to my recommended removal of certain projects and baseline capital additions as I identified in my GPIS section of my testimony. As I removed certain projects and baseline capital additions, I made the associated adjustment to the Accumulated Depreciation balance. The Company utilized a composite rate of 2.06% related to distribution plant (Weidmayer Schedule II-3 to II-5), and a composite depreciation rate 5.71% to General Plant. Using my recommended Distribution Plant disallowance of $10,296,636 and a Depreciation Rate of 2.06%, I calculate an adjustment of $212,111. Using my recommended General Plant disallowance of $75,385,331 and Depreciation Rate of 5.71, I calculate an adjustment of $4,304,502. This results in an overall adjustment of $4,516,613 to my Accumulated Depreciation Expense balance. My recommendation is shown on my Schedule DM-6.

4. <u>Working Capital</u>

Q. WHAT DID THE COMPANY PROPOSED RELATED TO ITS CASH WORKING CAPITAL (CWC)?

A. The Company has proposed a CWC balance of $62,148,000 as shown on Company Schedule C-4. Ms. Ressler stated that the CWC is the capital requirement arising from the difference between the lag in the receipt of revenue for rendering service and the lag in payment of cash expenses incurred to provide that service (Statement No. 3 at 9). The Company calculated an average daily expense balance of $1.843 million and multiplied that amount by the Net (Lead) Lag days of 28.41 to arrive at a balance of $51,365,000. The Company then added Interest Payments of ($4,667,000), Tax Payments Lag calculations of $4,402,000 and Prepaid Expenses of $10,047,000 to arrive at the CWC balance of $62,148,000. (Company Schedule C-4).

Q. DO YOU HAVE ANY ADJUSTMENTS OR CHANGES IN THE METHODOLOGY USED BY THE COMPANY TO CALCULATE ITS CWC?

A. No. I am accepting the Company's CWC methodology. My adjustments are related to the adjustments that I recommend for O&M Expenses, and other adjustments used to develop the CWC balance.

Q. WHAT ARE YOUR ADJUSTMENTS WITH RESPECT TO THE COMPANY'S CWC BALANCE?

A. I adjusted the Company's Cash Working Capital to incorporate my adjustments to my recommended O&M Expenses which flow through to the Cash Working Capital document.

My recommended balance is $61,561,127, or an adjustment of $587,278 to the Company's CWC balance and is shown on my Schedule DM-7.

6. <u>Accumulated Deferred Income Taxes (ADIT)</u>

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS ACCUMULATED DEFERRED INCOME TAXES (ADIT)?

A. The Company proposed a balance in its ADIT in the amount of $628,510,000 as shown on Company Schedule C-6. Company witness Ms. Nicole McKinney stated that this balance reflects the difference between the accelerated tax depreciation and straight-line depreciation on test year plant balances, net of offsets associated with Contributions in Aid of Construction. (Statement No. 7 at 7). This balance was further reduced by the state regulatory liability associated with UGI's Gas repairs tax method. As the state tax consequence of accelerated depreciation is flowed through, there is no associated ADIT balance. (Statement No. 7 at 7).

Q. HAS THE COMPANY REDUCED THE RATE BASE BALANCE BASED UPON THE UNAMORTIZED EXCESS DEFERRED FEDERAL INCOME TAXES (EDFIT)?

A. Ms. McKinney stated that the Company has reduced its Rate Base by the unamortized EDFIT, which is incorporated in the ADIT balance shown on Schedule C-6. (Statement No. 7 at 7). Ms. McKinney stated that the EDFIT adjustment as a result of the 2017 Tax Cuts and Jobs Act (TCJA) that would be amortized and flowed back to ratepayers in its FPFTY is included in the overall federal deferred tax expense calculated under the Company's Federal Income Tax calculation shown on Company Schedule D-33. The total amortization was approximately $4.3 million calculated using the Average Rate Assumption Method (ARAM) as required by tax normalization rules. (Statement No. 7 at 6).

Q. PLEASE EXPLAIN THE COMPANY'S REPAIRS TAX METHOD?

A. Ms. McKinney stated that the Company adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations.[6] The Company normalized its federal income tax expense claim, inclusive of the repairs tax deduction. The difference between the accelerated tax depreciation and book depreciation in the calculation of federal tax expense created an ADIT. The Company chose to flow through the repairs tax benefits over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, representing the repairs tax benefit that ratepayers have not yet received. (Statement No. 7 at 8). The Company reduced its rate base by the sum of the federal ADIT balance and the state repair regulatory liability. (Statement No. 7 at 8).

Q. WHAT ADJUSTMENTS DO YOU HAVE RELATED TO THE COMPANY'S ADIT BALANCE, THE EDFIT BALANCE AND THE STATE REPAIRS BALANCE?

A. I do not have any adjustments with respect to the Company's ADIT, EDFIT and State Repairs balances or the methodologies utilized to calculate these balances. My adjustments reflect my recommended removal of certain projects that I addressed in my GPIS testimony section.

Q. WHAT IS YOUR TOTAL ADJUSTMENT RELATED TO THE COMPANY'S OVERALL ADIT BALANCE?

A. I utilized my recommended balance of the Accumulated Depreciation adjustment of $4,516,613 and multiplied that amount by the Company's Deferred Tax rate of 28.8921% as shown on Company Schedule D-35. This produces an adjustment of $1,304,944. This is shown on my schedule DM-8.

C. OPERATING INCOME

1. <u>Operating Revenues</u>

Q. WHAT HAS THE COMPANY PROPOSED AS ITS OPERATING REVENUE AT PRESENT RATES AND PROPOSED RATES?

[6] The Company previously utilized this method in is prior rate case in Docket No. R-2019-3015162.

A. As shown on Company Schedule D-1, the Company calculated Operating Revenues at Present Rates of $1,062,724,000 and Revenues at Proposed Rates of $1,145,466,000. The difference represents the revenue increase of $82,742,000 or an increase of 7.78%.

Q. WHAT ADJUSTMENTS DID THE COMPANY MAKE TO DERIVE ITS PRESENT OPERATING REVENUES UNDER THE FPFTY PERIOD?

A. Company witness Ms. Tracy Hazenstab stated that the Revenues at Present Rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, the roll-in of revenues from the Distribution System Improvement Charge (DSIC) and other pro-forma annualizing and normalizing ratemaking adjustments. (Statement No. 2 at 12). The net effect of these adjustments is detailed on Schedule D-5. Company witness Ms. Sherry Epler stated that a 15-year normal heating degree day period was used to develop the sales and revenue forecasts. (Statement No. 8 at 7). Ms. Epler stated that a 15-year period is consistent with the methodology used for calculating normal heating degree days in previous UGI base rate cases. (Statement No. 8 at 7).

Q. DID THE COMPANY UPDATE ITS OPERATING REVENUE SUBSEQUENT TO THE INITIAL FILING?

A. No, the Company did not update its Operating Revenue subsequent to the initial filing.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S PRESENT RATE REVENUE?

A. With respect to the Company's Forfeited Discounts, Miscellaneous Revenues, and Rent from Gas Properties, I am recommending normalizing these revenues using a three-year period 2021-2023. I utilized the balance of these revenues as shown on Company Exhibit Schedule D-2 for the HTY 2021, ($11,634,000) Schedule D-2 for the FTY 2022 ($19,181,000) and Schedule D-2 for the FPFTY ($10,287,000). These balances average out to $10,700,667, or an increase of $413,667. I am of the opinion that these types of revenues do fluctuate and change from year to year, and it is appropriate to normalize these revenues, including forecasted revenues, prospectively. My adjustments are shown on my Schedule DM-4.

2. OPERATION AND MAINTENANCE EXPENSES

Q. HOW DID THE COMPANY DEVELOP ITS OPERATING EXPENSES PRESENTED FOR RECOVERY IN THIS RATE PROCEEDING?

A. According to Ms. Hazenstab, the Operating and Maintenance expenses are developed based upon the review of trends, monthly expenditure patterns, and new or changed programs. Employee levels are reviewed, and appropriate staffing levels are set for the upcoming fiscal year. Allocated expenses from shared administrative and general functions within UGI and from other affiliated companies providing shared services to UGI Gas are used to develop the budgeted Statement of Operations. (Statement No. 2 at 8). Allocated expenses in the Statement of Operations included functions such as accounting, rates, gas supply, human resources, information systems, payroll, and remittance processing, which are performed in accordance with PUC-approved methods of allocation and affiliated interest arrangements or agreements. (Statement No. 2 at 8). Ms. Hazenstab stated that the Operating Budget is in accordance with Act 11 of 2012, which provides for the establishment of an Operating Budget for an additional fiscal year in the future or the FPFTY. (Statement No. 2 at 9). UGI Gas incurs costs for services provided by UGI Corp. and other affiliated companies, as well as allocated and assigned costs between UGI Electric and UGI Gas. The allocations are made by using a methodology applicable to the cost, or if no one methodology is specific to the cost, by using a formula referred to as the Modified Wisconsin Formula (MWF), or another reasonable allocation methodology. (Statement No. 2 at 9-10). The budget information is the starting point for the Company's claims and is adjusted as appropriate to reflect new information gained since the completion of the budgeted process and through application of other appropriate principles. (Statement No. 2 at 10).

Q. WHAT LEVEL OF OPERATING EXPENSES HAS THE COMPANY PROPOSED TO RECOVER IN THIS PROCEEDING UNDER ITS FPFTY TEST PERIOD?

A. As shown on Company Schedule D-1, the Company has proposed to recover $690,669,000 of Operating Expenses for the FPFTY period.[7] Ms. Hazenstab stated that these Operating Expenses reflect a normal, ongoing level of operations and are based upon the budgeted

[7] Excludes Depreciation Expense, Taxes other than Income and Income Taxes.

level of expenses. The budgeted data by FERC account was adjusted in accordance with Commission precedent and generally accepted ratemaking principles. (Statement No. 2 at 15).

a. <u>Gas Production</u>

Q. WHAT DID THE COMPANY PROPOSE REGARDING ITS GAS PRODUCTION EXPENSES?

A. The Company proposed a Gas Production Expense balance of $997,000 as shown on Company Schedules D-2 and D-3. The Company began with a balance of $14,000 and added $983,000. Company witness Ms. Ressler stated that this increase of $983,000 was for Environmental Remediation Expenses (Adjustment #1) related to UGI Gas's obligations to conduct remediation activities under a Consent Order Agreement (COA) with the PA Department of Environmental Protection (DEP).(Statement No. 3 at 16-17).

Q. HOW DID THE COMPANY CALCULATE THE ADJUSTMENT OF $983,000?

A. Ms. Ressler normalized the recovery of the Environmental Remediation expense by averaging out the last three years of cash expenses for remediation under the COA (2019-2021), $5.171 million of which represents the amount that the Company anticipates it will spend in the FPFTY period. The difference between the annual amount of $5.171 million and the budgeted amount of $4.188 million or $983,000 is the increase proposed to be recovered. (Statement No. 3 at 17).

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S GAS PRODUCTION EXPENSE?

A. In response to I&E-RE-44 **(Begin Highly Confidential)** the Company provided the balances for the Environmental Remediation (Adjustment #1) for the fiscal years 2017 and 2018. These costs were $6,009,000 in 2017 and $4,115,000 in 2018. The Company stated that its basis for using a three-year average was to eliminate high and low spending and approximate an average year of spending. I am accepting the Company's five years of actual and projected spending. I recommend the Company use a five-year average instead of a three-year average to be consistent with its other environmental adjustments (#2 Company Schedule D-8 and in response to I&E-RE-44), particularly since Adjustment #2 was approved by the Commission in the Company's Gas Rate Case Settlement in Docket No. R-2019-3015162. **(End Highly Confidential).** I believe that consistency among the various Environmental Adjustments periods is appropriate as it further normalizes these costs. Given the ongoing annual cash expenditures and the Company's annual rate case filings, it is appropriate to normalize these costs over a longer period of time. My recommended five-year average adjusts the Company's balance from $983,000 to $939,600 (rounded to $940,000) which is an adjustment of $43,733 and is shown on my Schedule DM-9.

Q. HAS THE COMPANY PROPOSED AN ADJUSTMENT TO ITS ENVIRONMENTAL EXPENDITURES #2?

A. No. Ms. Ressler's testimony (Statement No. 3 at 18) explained that the Company did not make an adjustment to its Remediation Expense – MGP expenses in this proceeding. The Company stated that in the 2020 Base Rate Case, the Company was authorized to amortize $8.103 million of under-recovered MGP expenses over a five-year period or $1.621 million per year for under-recovered MGP expenses for the periods prior to September 30, 2018. In the 2020 Base Rate Case, the Company was authorized to amortize an additional $1.219 million over a five-year period or $0.24 million per year for under-recovered MGP expenses for Fiscal Year 2019. The Company budgeted this same amount (Company Schedule D-8 line 11) for expense purposes, and as such, no adjustment is needed for this item.

b. <u>Gas Supply Production</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS GAS SUPPLY PRODUCTION EXPENSE?

A. Company witness Ms. Hazenstab stated that the Company has increased its Gas Supply Production costs by $38,877,000 for the FPFTY period. This adjustment is designed to increase purchased gas cost expense by the same amount of the gas cost revenue adjustments. The Company recovers its purchased gas costs on a dollar for dollar basis with no profit through an automatic adjustment clause mechanism pursuant to Section 1307(f) of the Public Utility Code. The increase in purchased gas costs equals the increase in the gas cost revenue (Statement No. 2 at 16). This adjustment has no effect on net operating income.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I have no adjustments to the Company's Gas Supply Production costs of $38,877,000 and am accepting this adjustment. This is shown on my Schedule DM-10.

c. <u>Company Overall Salary & Wages (S&W) Increase</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS SALARY AND WAGES INCREASE?

A. The Company proposed a budgeted year balance of $79,358,000 related to Salary and Wages for the FPFTY period as shown on Company Schedule D-7. The Company made a positive adjustment of $2.385 million to the Budgeted Year that can be broken down into three parts: (1) $1,148,000 for salary increases and $51,000 for incremental bonus compensation for a total of $1,199,000. This adjustment aligns salaries for specific positions with relevant industry pay-scales. (Statement No. 2 at 18 and Schedule D-9); (2) $643,000 for twenty unbudgeted positions for field operations which are needed for succession planning (Statement No. 2 at 18 and Schedule D-17) and; (3) $543,000 for five new positions to implement Transportation Security Administration (TSA) Directives, including $38,000 related to incentive bonuses. (Statement No. 2 at 18 and Schedule D-9). The total payroll as distributed was calculated at $82,929,000. (Schedule D-7).

Q. HOW DID THE COMPANY DEVELOP ITS PROPOSED PRO-FORMA S&W INCREASE OF $82,929,000?

A. The Company adjusted the balance of $81,743,000 shown on Company Schedule D-7 by adding $1,186,000 of additional S&W expenses to arrive at a balance of $82,929,000. The Company calculated the $1,186,000 of additional S&W expenses by applying a 3.00% salary increase to its Union Employees (effective 6/1/2023), its Non-Union Employees (effective 4/1/2023) and its Exempt Employees (effective 12/1/2022). The Company then allocated 67% of Union Employees to the Operating Expense category, 50% to the Non-Exempt Employees and 17% to the Exempt Employees. (Company Schedule D-7). The total S&W expense proposed in this proceeding is therefore $82,929,000 as shown on Company Schedule D-7.

Q. HOW DID THE COMPANY DEVELOP ITS S&W ADJUSTMENTS AND WHAT INFORMATION DID THE COMPANY USE?

A. According to Mr. Brown, the Company made these adjustments as a result of recent compensation benchmarking review activities that focused on how UGI may continue to remain productive in an increasingly competitive labor market. Mr. Brown stated that the Company continues its efforts to attract, recruit, train and retain those professional, technical and field-qualified personnel and resources necessary to implement, operate and maintain a safe and reliable natural gas distribution system for all customers. (Statement No. 1 at 26).

Q. WHAT COMPENSATION BENCHMARKS HAS THE COMPANY PROPOSED IN THIS CASE?

A. Mr. Brown relied on data provided by the American Gas Association (AGA) and has begun to implement salary adjustments based upon this study. The planned adjustments affect 990 employees and will result in about $1.2 million of incremental costs to be applied to the Company's operating expense for UGI in the FPFTY. (Statement No. 1 at 27).

Q. WHAT DID MR. BROWN ADDRESS AS TO THE NEED FOR THE COMPENSATION ADJUSTMENTS?

A. Mr. Brown stated that the Company has experienced an increase in voluntary employee turnover as the available labor market has become constrained and increasingly competitive. This is particularly true for roles that require experienced employees. (Statement No. 1 at 27). More employees, including those with years of regulatory experience are moving on to other opportunities outside of UGI. The Company has encountered difficulties finding internal interest for certain critical exempt positions. The purpose of implementing these compensation benchmarks is to retain existing experienced employees and compete for qualified employees in order to fill needed roles in a very competitive job market. (Statement No. 1 at 28). The Company provided a breakdown of the Compensation Benchmark adjustments on Table 7 page 28 of Statement No. 1.

Q. DID THE COMPANY INCLUDE ANY INCENTIVE COMPENSATION IN ITS FPFTY PERIOD?

A. Yes. In SDR-RR-27, the Company included $11,129,787 of Incentive Compensation for the FPFTY period.

Q. HOW DID THE COMPANY DEVELOP ITS $11,129,787 INCENTIVE COMPENSATION BALANCE?

A. In response to Confidential I&E-RE-17 the Company broke the development of the $11,129,787 of Incentive Compensation. The following is a breakdown:

(Begin Confidential)

UGI Utilities:

Management Incentive Plan	$2,603,000
Executive Bonus	$ 714,000
Restricted Stock Awards	$ 766,000
Stock Options	$ 401,000
Deferred Compensation (SERP)[8]	$ 433,000
Total at UGI Utilities – Gas	**$4,916,000**

Allocated from UGI Corporation:

Incentive Compensation[9]	$1,364,000
Stock Options/Restricted Stock Awards	$2,319,000
Directors' Equity Compensation	$ 555,000
Shared Executive – Incentive Compensation	$ 512,000
Stock Options and Restricted Stock Awards	$1,153,000
Incentive Compensation[10]	$ 309,000
Total allocated from UGI Corp. – Gas	**$6,213,000**
Grand Total	**$11,129,787**

(End Confidential)

Q. DID THE COMPANY PROVIDE A SET OF GOALS AND PERFORMANCE METRICS SUPPORTING ITS $11,129,787 INCENTIVE COMPENSATION BALANCE?

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[8]**(Begin Confidential)** SERP refers to Supplemental Executive Retirement Plan (**End Confidential)**
[9] **(Begin Confidential)** Represents Indirect Allocation via MWF **(End Confidential)**
[10] **(Begin Confidential**) Represents direct Costs to Utilities **(End Confidential)**

A. Yes. In response to I&E-RE-17 (Confidential), Attachment 17.3, and 17.4 the Company provided goals related to the Company's UNITE Incentive Compensation Plan. A more detailed review and description of the UNITE Incentive Compensation Plan is discussed under Administrative & General Expense section of my testimony. My adjustments to the Company's UNITE Incentive Compensation plan are also discussed under the Administrative & General Expense section of my testimony.

Q. HOW MANY ADDITIONAL EMPLOYEES HAS THE COMPANY PROPOSED TO INCLUDE IN ITS FILING?

A. As identified in response to OCA-Set III-7, the Company projected 64 additional employees through the FY 2023 (the end of the test year).

Q. PLEASE DESCRIBE THE ADDITIONAL EMPLOYEES THE COMPANY HAS PROPOSED IN ITS FILING?

A. In response to OCA-Set III-7 the Company has proposed 64 additional hires through FY 2023. 20 of those hires relate to the Company's succession planning for Operations (Company Schedule D-17), and 5 of those hires relate to the Company's Cybersecurity (TSA Security Directives Company Schedule D-9). These 25 hires have been approved in the Company's budget. The Company also included 5 additional hires that are either for Succession Planning or for Training. 17 of the hires are for replacements in which 17 candidates have been identified. The remaining 17 open positions also relate to replacement, but candidates have not been identified. The Company stated that the goal is to fill the open positions by 60 days past the approved requisition; however, filling the positions can take longer depending on the labor market at the time of the fill and other factors. (OCA-III-5). In response to OCA-III-12, the Company provided an update to the Cybersecurity positions. The Company stated that these employees are anticipated to start in April 2022. For this reason, Company plans to further update the salary levels to reflect an increase of $87,323 over the as-filed salary level of $505,000.

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S EMPLOYEE PROJECTIONS?

A. I am accepting the Company's level of employees except for the 17 open positions that relate to replacement and for which candidates have not been identified. I am recommending removing the funding for these 17 positions as I believe these positions may or may not be filled during the FY 2023 and are speculative at best. As indicated in response to OCA-III-7, the Company only anticipates these hires depending on the labor market and other factors. My adjustment of $779,368 is calculated by using the average employee salary of $45,845 which I calculated by taking the Company's total payroll shown on Attachment I&E-RE-5-A of $77,358,000 and dividing that number by the number of total employee count of 1,731 as of the FPFTY period ending September 30, 2023. I then took the average salary of $45,845 and multiplied that amount by anticipated hires of 17 employees to arrive at my adjustment of $779,368. This is shown on my Schedule DM-11, which is carried over to Schedule DM-4.

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S S&W INCREASE RELATED TO INCENTIVE COMPENSATION COSTS?

A. My adjustment is to the level of Incentive Compensation related to the Company's UNITE Incentive Compensation Plan. As more fully explained under my Administrative & General Expenses, and as addressed above, I am removing **(Begin Confidential)** $2,312,000 of expenses related to Executive Bonus, Restricted Stock Awards, Stock Options and Deferred Compensation SERP. In response to OCA-XI (Confidential), the Company provided information related to payout dates, notification dates and weighted targets for each plan and to ascertain whether these targets and goals benefit customers. The Management Incentive Plan and executive bonuses for the fiscal year ending September 30 are paid out no later than the following December 31, and recipients are notified of their earned amounts approximately two week prior to the payout. For the Stock Awards, the employees have 10 years from the grant date to exercise an option and at least one tranche of a three-year award vests in January each year and the participants receive award letters at the time of grant that outlines the terms of the award including the vest date which would indicate payment date if the award met the target. Regarding the Deferred Compensation the Company stated that it can vary based upon specific elections made and all executives have a six-month wait period from time of retirement to receive any benefits from the SERP or SSP. In response to I&E-RE-17.3 (Confidential) the Company stated that the timeline and goals for each phase are established and will continue to be refined to ensure successful transition of streamlined processes and systems going forward. **(End Confidential)**

Q. IS ANY OF THIS INCENTIVE COMPENSATION RELATED TO THE UNITE INITIATIVE?

A. No. According to the response to OCA-XI-1 (**Begin Confidential**), only the Asset Data Collection (ADC) project has incentive compensation as this plan is designed for those employees who are dedicated to the ADC project of which is expected to go into service for UGI Gas in January 2023. (**End Confidential**).

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENTS TO THE COMPANY'S PROPOSED S&W INCREASE?

A. My adjustments to open positions and incentive compensation for the Management Incentive Plan at UGI Utilities – Gas portion, total $5,694,368.

Q. HAVE YOU ALLOCATED YOUR ADJUSTMENTS TO THE COMPANY'S S&W INCREASE BY ACCOUNT CATEGORIES?

A. Yes. My Schedule DM-11 shows the allocation by account categories that I performed to adjust the Company's S&W adjustment. I've also addressed this allocation to my adjustments for each of the Company's Operating Expenses below.

d. <u>Distribution Operations and Maintenance Expense</u>

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS DISTRIBUTION EXPENSES – OPERATIONS AND MAINTENANCE?

A. The Company has proposed a Distribution Expense of $84,369,000 for the budget year ending 9/30/2023. To that balance, the Company made the following adjustments; (1) Salaries and Wages - $611,000; (2) Compensation Benchmark - $1,318,900; (3) Cybersecurity personnel - $591,000; (4) Succession Planning personnel - $767,000 and; (5) $565,000 for Annual Capacity Lease Charge. The total proforma balance for

Distribution Operations and Maintenance expenses for the FPFTY period is $88,222,000[11], an adjustment of $3,853,000. This is shown on Company Schedule D-2 and D-3.

Q. ARE THERE ANY OTHER SPECIFIC ADJUSTMENTS YOU MADE TO THE COMPANY'S DISTRIBUTION OPERATION AND MAINTENANCE EXPENSE?

A. Yes. I made an adjustment to the Company's Outside Contractors expenses and services as identified in response to OCA-III-33. This will be explained further in my discussions under Distribution Operations and Maintenance Expenses.

1. <u>Salary and Wages (Schedule D-6 and 7) - $611,000</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS SALARY AND WAGES (S&W) FOR ITS DISTRIBUTION EXPENSE?

A. The Company has proposed $611,000 of additional S&W expense. This balance reflects a 3.00% wage increase for unionized, exempt and non-exempt employees to reflect the end of the FPFTY operating conditions and annualizes payroll expense among the various cost accounts. (Statement No. 2 at 17).

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S S&W EXPENSE?

A. I am accepting the Company's proposed merit increases of $416,000 and $195,000 related to Operations and Maintenance expense labor, respectively.

2. <u>Compensation Benchmark – (Schedule D-9) $1,318,900</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS COMPENSATION BENCHMARK?

A. The Company has proposed an overall Compensation Benchmark adjustment of $1,318,900, which is allocated to the Distribution Expense category. ($1,148,000 benchmark adjustment, $51,000 Incremental Incentive bonus and $120,000 in benefits). The balance of $1,318,900 was calculated by taking the benchmark data from the AGA that affect 990 employees and making adjustments to several categories of employment

[11] Differences due to rounding

resulting in an increase of $1,148,000 (Statement No. 1 at 27 and Company Schedule D-9). As previously described, the Company initiated the Compensation Benchmark adjustment in response to a competitive labor market and the need to retain, attract and maintain experienced employees. (Statement No. 1 at 28). The Company reviewed salary data provided by AGA by position and then compared current individual employee compensation levels to the AGA midpoint by role, or other survey data where a job match could not be identified utilizing AGA data. Compensation targets were then identified based upon years of service in order to determine which specific employees warranted adjustments. (Statement No. 1 at 29). Table 7 on page 28 of Statement No. 1 shows the number of employees affected by the compensation adjustments by functional department and includes operating expenses and incentive compensation adjustments based upon the employees' predetermined time allocation. The Company stated that increases are planned to be phase-in beginning early 2022 and are expected to be completed by September 2022 (Statement No. 1 at 29).

Q. ARE THE COMPANY'S COMPENSATION BENCHMARK ADJUSTMENT RELATED TO BASE SALARY ADJUSTMENTS?

A. Yes, according to the response to OCA-III-13, Mr. Brown stated that the adjustment of $1,148,000 is related to non-exempt and exempt positions and was initiated to address the Company's inability to fill critical positions, retain existing experienced employees and compete for qualified employees in order to fill needed roles in a very competitive job market. (Statement No. 1 at 28).

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S COMPENSATION BENCHMARK PROPOSAL?

A. My adjustment is related to the Incentive Compensation of $51,000 included as part of its Compensation Benchmark. I am recommending that the Incentive Compensation costs of $51,000 be removed from the Company's S&W expenses. Typically, incentive compensation and bonuses are linked to goals, performance matrices, and objectives that need to be met before the incentive compensation is paid out to employees. I do not see any evidence that shows performance goals are being or will be met. The Company has stated that these specific employees under the Compensation Benchmark adjustment will be eligible for an incentive bonus in FY 2023 (I&E-RE-13). I believe this is too far in advance to state whether these employees will actually achieve goals performance matrices or objectives (which the Company has not identified).

3. <u>Cybersecurity – Additional Employees – (Schedule D-9) $591,000</u>

Q. WHAT HAS THE COMPANY PROVIDED WITH RESPECT TO ITS COSTS RELATED TO CYBERSECURITY?

A. The Company proposed an approximate $591,000 expense adjustment related to the hiring of 5 cybersecurity positions at $101,000 per employee, with benefits of $48,510 and incentive bonuses of $38,000. This is shown on Company Schedule D-9. Mr. Brown stated that these 5 additional employee would be hired in direct response to the TSA cybersecurity directives which were issued in May and July 2021 to protect against the impact of malicious cyber intrusions affecting the nation's pipelines. (Statement No. 1 at 29). Mr. Brown stated that the directive included about 90 specific required actions to be applied to information and operational technology systems. The Company has identified that 5 additional full-time employees are required to support these new TSA cybersecurity directive requirements and these employees will be needed for the administration and management of the new cybersecurity procedures and for the supervisory control and data acquisition system (SCADA) environment as cyber professionals will monitor threats and protect the isolated SCADA network. (Statement No. 1 at 29). The 5 positions are being added at the identified median salary plus employment benefits. Mr. Brown stated that the Company's proposed staffing aligns with other utilities that are taking the same approach to satisfy the TSA requirements. (Statement No. 1 at 30). In response to OCA-III-12 the Company provided an update to the hiring status. Three of the positions are expected to start employment during April 2022, and two of the positions are anticipated to start in October 2022.

Q. DID THE COMPANY UPDATE THE WAGE ADJUSTMENT SUBSEQUENT TO THE FILING OF THIS CASE?

A. Yes. The Company identified increases to the beginning salaries from $505,000 to $585,300, and an increase to incentive bonuses from $38,000 to $45,000, or an increase of about $87,000. The Company stated that it will reflect this increase as part of its claim in this case at the appropriate time. (OCA-III-12).

Q. HAVE OTHER UTILITIES TAKEN THE SAME APPROACH OF ADDING EMPLOYEES TO SATISFY THE TSA CYBERSECURITY DIRECTIVES?

A. According to the response to OCA-VII-12, the Company stated that all utilities are subject to the new TSA cybersecurity directives and will need to dedicate the resources required to meet the incremental standards. The Company stated that it is aware that a vast majority of local distribution company respondents were planning resource additions to meet the TSA directives.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am accepting the Company's proposal related to the 5 positions for TSA compliant directives. My only adjustment is to the removal of the as filed $38,000 of incentive bonus. I believe incentive bonuses are linked to goals, performance matrices and objectives that are needed to be achieved before the payout to employees. I have not seen any evidence of the goals, performance matrices or objectives related to the incentive bonuses. The Company has stated that these employees will be eligible for an incentive bonus in FY 2023 (I&E-RE-13). I believe this is too far in advance to state whether these employees will actually achieve goals performance matrices or objectives (which the Company has not identified).

4. <u>Succession Planning – (Schedule D-17) $767,000</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO SUCCESSION PLANNING?

A. The Company is proposing to include 20 additional employees in 2023 related to Succession Planning for Operations to address staffing needs. This is comprised of $643,000 of salary and $124,000 of employee benefits, which are shown on Company Schedule D-17. Company witness, Mr. Timothy Angstadt, stated that the need for the additional 20 employees is due to forecasted retirements and attrition of newer employees, and, given these challenges, the Company requires an aggressive and multifaceted approach so that the Company can continue to accomplish fieldwork critical to the safety and reliability of its operations, including meeting planned replacement goals pursuant to the Company's LTIIP. (Statement No. 9 at 16).

Q. WHAT TYPES OF EMPLOYEES ARE THE COMPANY PROPOSING TO HIRE?

A. Mr. Angstadt stated that the Company is proposing to hire gas mechanics, field technicians, equipment operators, laborers, meter readers and contract inspectors, as well as, clerical, supervisory and leadership staff to support these roles. The majority of these employees will be union. (Statement No. 9 at 17).

Q. WHAT HAS BEEN THE TURNOVER OF EMPLOYEES AT THE COMPANY?

A. According to Mr. Angstadt, the Company has seen significant turnover of apprentice level employees who remain at the Company for less than 5 years. Mr. Angstadt stated that over 100 employees with 5 years of experience or less have left the Company, and 27 employees with more than 5 years of experience voluntarily left the Company. (Statement No. 9 at 19). While the Company has consistently replaced these apprentice level employees the ongoing loss of apprentice level employees has created a growing gap of experience between the number of apprentice employees and those that have 5 years or more of experience. (Statement No, 9 at 19).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I reviewed the response to OCA-III-7 and based upon the response, the Company has an approved budget to add the 20 additional employees related to Succession Planning, and these employees are expected to be hired in June 2022. I am accepting the Company's addition of 20 employees at an aggregate base salary of $643,000. With respect to Employee Benefits, I am capping the expense at 10% of salary which is what the Company has proposed under its Adjustment 1 – Compensation Benchmark (Schedule D-9) and Adjustment 2 – Cybersecurity (Schedule D-9). The average employee salary is $643,000 divided by 20 equals $32,150. The Company calculated benefits by dividing $124,000 by 20 to equal $6,200. $6,200 divided by $32,150 equals 19.28%. Capping the employee benefits at 10% calculates to $3,215 per employee, and $64,300 when multiplied by 20 employees. In response to OCA-III-17, the Company stated that $6,200 represented the portion of the average benefit cost remaining in OPEX, with the remaining cost allocated to capital spending. The $9,702 of employee benefits was the baseline used for the benefit costs on the new positions. I am not sure why these category of employees' benefits are higher than those under the Compensation Benchmark employees and the cybersecurity employees. My adjustment is shown on my Schedule DM-12.

5. <u>Auburn Annual Capacity Lease Charge – (Schedule D-15) $565,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS ANNUAL CAPACITY LEASE CHARGE?

A. Ms. Hazenstab stated that the balance of $565,000 related to the Annual Capacity Lease Charge is to recover unbudgeted rent expense associated with the Auburn Capacity Lease Agreement approved by the Commission in Docket No. G-2021-3028753 on November 22, 2021. Ms. Hazenstab stated that this amount pertains to an agreement to lease additional capacity for a Rate XD customer (Proctor and Gamble Paper and Products Company) and will be directly assigned to the customer in the Company's cost of service study. (Statement No. 2 at 26). Ms. Hazenstab stated that the capacity lease will expand available sources of reliable and competitively priced supplies for the Company and its customers. The Company anticipated the capacity lease becoming available on July 1, 2022. (Statement No. 2 at 24-25).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's balance of $565,000. This is shown on my Schedule DM-12.

Q. WHAT OTHER ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S DISTRIBUTION OPERATION AND MAINTENANCE EXPENSES?

A. In response to OCA-Set-III-33, I asked the Company to provide information related to its outside contractor expenses and the services provided. These are accounted for in Administrative and General Expenses, Customer Account Operations Expenses and Distribution Expenses. Based upon the response, I am recommending normalizing the Company's outside contractor expenses under each of the Company's operating expense accounts. As shown in OCA-Set-III-33, the Company provided a breakdown of its outside contractors' expenses for the periods 2019 through the FPFTY. These costs are mainly related to contractor labor categorized as other, restoration, pipeline and traffic removal. The Company proposed a total Outside Contractor Expense balance for the FPFTY period for Distribution Expenses of $20.286 million. I am recommending normalizing these costs by averaging out the expenses over a three- year period (2020-2022) resulting in a decrease of $2.114 million. I believe that these types of costs do fluctuate over time because they are outside the control of the Company, they are volatile in nature and are unpredictable. There is no discernable trend that shows a gradual or incremental increase in these expenses over time.

Q. WHAT ARE YOUR TOTAL DISTRIBUTION EXPENSE ADJUSTMENTS?

A. As shown on my Schedule DM-12, my overall adjustment to the Company's Distribution Expenses is a reduction of $2,268,008 and my balance is $85,954,277 from the Company's proposed forecasted expense balance of $88,222,285.

e. Customer Accounts Expense

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS CUSTOMER ACCOUNTS EXPENSE?

A. As shown on Company Schedule D-2, the Company proposed a Budgeted balance for the year ending 9/30/2023 in the amount of $40,541,000. To that amount the Company included the following: (1) Salaries and Wages of $216,000; (2) Emergency Relief Program (ERP) of $92,000; (3) Unrecovered Interest on Customer Deposits of $972,000 and; (4) Universal Service Expenses of $548,000. These adjustments brings the total Customer Accounts Expense to $42,370,000 for the pro forma period ending 9/30/2023. I will discuss each of these 4 adjustments below:

1. Salary and Wages (Schedule D-6 and 7) - $216,000

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS SALARY AND WAGES?

A. The Company proposed total adjustments to its Salary and Wages of $216,000. This balance reflects a 3.00% wage increase for unionized, exempt and non-exempt employees to reflect the end of the FPFTY operating conditions and annualizes payroll expense among the various cost accounts.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S SALARY AND WAGE EXPENSE ADJUSTMENT?

A. As I indicated previously in my Distribution Expense category, I am accepting the Company's 3% wage increase of $216,000.

2. <u>Emergency Relief Program (Schedule D-12) $92,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS EMERGENCY RELIEF PROGRAM (ERP)?

A. As shown on Schedule D-12, the Company proposed an Emergency Relief Program cost of $92,000. The Company has proposed to amortize the balance of $922,000 over a ten-year period. Ms. Ressler stated that this balance reflects the recovery of costs associated with the temporary Emergency Relief Program in response to the COVID-19 Pandemic, which was implemented to aid customers who were unable to fully pay their utility bills. (Statement No. 3 at 21). Ms. Ressler stated that the cost of the program included implementation expenses and direct billing credits and that the program was approved within the settlement agreement in the Company's 2020 Gas Base Rate Case in Docket No. R-2019-3015162. The 10-year period was pursuant to the Commission Order approving the settlement in the 2020 Gas Base Rate Case. (Statement No. 3 at 21).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the $92,000 balance and the 10-year amortization, as this was approved by the Commission in the 2020 rate case (ordering paragraph 17-19) OCA-Set III-24.

3. <u>Unrecovered Interest on Customer Deposits (Schedule D-15) $972,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS UNRECOVERED INTEREST ON CUSTOMER DEPOSITS?

A. As shown on Company Schedule D-15, the Company proposed to recover $972,000 of unrecovered interest on customer deposits. Ms. Hazenstab stated that the Company is required to pay interest on customer deposits that it holds in accordance with its tariff requirements. This cost has not been reflected in the Company's operating budget. The Company has utilized a 4.50% interest rate to calculate this balance anticipated for the FPFTY period. The balance is currently calculated to be $21.6 million. (Statement No. 2 at 21).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S UNRECOVERED INTEREST ON CUSTOMER DEPOSITS?

A. After a review of the documents, I am accepting the Company's balance of $972,000.

4. <u>Universal Service Program (USP) Expenses (Schedule D-16) $548,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS UNIVERSAL SERVICE EXPENSES?

A. The Company has calculated a Universal Service Expense of $548,000 as shown on Company Schedule D-16. Ms. Hazenstab stated that this adjustment normalized the amount of USP expense recovered through the Company's USP Rider based upon the level of Universal Service Rider charge effective at the time of the Company's filing. (Statement No. 2 at 22). This expense recovered costs of the Company's Customer Assistance Program (CAP) Credits, Pre-Program Arrearages, third party administrator expenses, LIURP expense and administrative costs associated with its Project Share program. As the USP Rider is a fully reconcilable rider, the USP adjustment assured that expenses related to the existing rider are aligned with revenues and that no impact related to USP flows through the revenue requirement calculation. (Statement No. 2 at 22-23).

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S UNIVERSAL SERVICE EXPENSES?

A. After a review of the documents and discovery responses, I do not have any changes to the Company's proposal. I am accepting the Company Universal Service Expense balance.

Q. WHAT OTHER ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S CUSTOMER ACCOUNTS EXPENSE?

A. As I normalized the Company's Outside Services under Distribution Expenses, I am normalizing the Company's Outside Contractor Expenses under Customer Accounts Expense to be consistent across all accounts. In response to OCA-Set III-33, the Company provided a breakdown of its Outside Contractors Expenses for the periods 2019 through the FPFTY. These costs are mainly related to contractor labor and specifically the categories of other, restoration, pipeline and traffic removal. The Company proposed a total Outside Contractor Expense balance for the FPFTY period of $54,000. Normalizing these costs by averaging out the expenses over a three- year period (2020-2022) results in a decrease of $9,000. These types of costs do fluctuate over time because they are outside the control of the Company, they are volatile in nature and are unpredictable. There is no discernable trend that shows a gradual or incremental increase in these expenses over time.

Q. WHAT ARE YOUR TOTAL ADJUSTMENTS TO THE COMPANY'S CUSTOMER ACCOUNTS EXPENSE?

A. My total adjustment to the Company's Customer Accounts Expense is $42,360,200 which is $9,000 lower than the Company's pro forma balance of $42,369,000. This is shown on my Schedule DM-13.

f. <u>Uncollectible Accounts Expense (Schedule D-11) $17,958,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. The Company has proposed a total balance to its Uncollectible Accounts Expense of $17,958,000. (Company Schedule D-1). The Company began with a balance of $14,419,000 and added $2,026,000 of additional uncollectible expense based upon its 2023 budgeted uncollectible balance of $15.4 million[12] and its pro forma Present Rate Revenue uncollectible balance of $17.426 million (Present Rate Revenue of $1,058,040,000 times a three-year average uncollectible balance of 1.647%). The Company then made an adjustment of $150,000 related to the amortization of the regulatory asset balance of $1.503[13] million for COVID-19 Pandemic costs over a ten-year amortization period in accordance with the Commission Order dated October 8, 2020, R-2019-3015162. (Company Schedule D-11). (Statement No. 3 at 20). This reflects the excess of

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[12] The Company calculated the $15.4 million based upon a 1.5% estimated uncollectible rate. See response to OCA-VII-1.

[13] Includes $896,000 and $607,000 in 2021 and 2022, respectively, which was recorded as a regulatory asset associated with COVID-19.

uncollectible expenses incurred over the established threshold of $12.810 million per year over a ten-year period effective at the beginning of the FPFTY period. (Statement No. 3 at 20).

Q. WHAT OTHER ADJUSTMENTS DID THE COMPANY MAKE TO ITS UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. The Company included an additional Uncollectible Accounts Expense by taking the proposed revenue requirement increase of $82.742 million and multiplying that amount by the three-year average Uncollectible Accounts ratio of 1.647% to arrive at a balance of $1.363 million. (Company Schedule D-2).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am accepting the Company's three-year average ratio or uncollectible of 1.647%, and the regulatory asset balance of $1.503 million amortized over 10-years, which was approved by the Commission in the Company's 2020 rate case. My adjustment is related to my recommended revenue requirement decrease of $38,673,989 which is shown on my Operating Income Schedule DM-4.

Q. WHAT IS YOUR TOTAL RECOMMENDED BALANCE RELATED TO THE COMPANY'S UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. My total adjustment is a reduction of $1,980,742 and is shown on my Schedule DM-4.

g. <u>Customer Information & Services Expense</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER INFORMATION & SERVICE EXPENSE?

A. The Company proposed a balance of Customer Information & Services Expenses of $13.864 million as shown on Company Schedule D-2. The Company began with a balance of $10.368 million and added an adjustment to Salaries and Wages of $16,000 and Energy Efficiency & Conservation costs of $3.480 million to arrive at a balance of $13,864,000. I will address these two adjustments below.

1. <u>Salary and Wages (Schedule D-6 and 7) - $16,000</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS SALARY AND WAGES?

A. As shown on Company Schedule D-7, the Company proposed an increase of $16,000. This increase reflects a 3.00% wage increase for unionized, exempt and non-exempt employees to address the end of the FPFTY operating conditions and annualizes payroll expense among the various cost accounts.

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S PROPOSED $16,000 SALARY & WAGE INCREASE?

A. As I indicated previously in my testimony, I am accepting the Company's 3% wage increase of $16,000.

2. <u>Energy Efficiency & Conservation (Schedule D-19) $3,480,000</u>

Q. WHAT HAS THE COMPANY PROPOSED REGARDING ENERGY EFFICIENCY & CONSERVATION (EE&C)?

A. Ms. Hazenstab stated that the EE&C aligns the amount of EE&C expense with the EE&C Rider charges effective at the time of the Company's filing in this matter. (Statement No. 2 at 23). The EE&C Rider recovers the Labor and Administrative, Prescriptive Program, Retrofit Program, New Construction Program, Custom Program, Legal and Consulting, Combined Heat and Power, and other costs associated with the Company's EE&C program (Statement No. 2 at 23). The $3.480 million increase aligns with the Company's current EE&C charge, and as it is fully reconcilable, the EE&C adjustment assures that the expenses related to the existing rider are aligned with revenues and that no impact related to EE&C flows through to the revenue requirement calculation. (Statement No. 2 at 23).

Q. WHAT IS YOUR ADJUSTMENT?

A. In response to OCA-VII-6, I asked the Company for a breakdown of the program costs of $9.239 million and the adjusted program costs of $12.719 million. The Company provided a breakdown of these costs in I&E-RE-51. The administrative costs represents an average of 6.84% to total program costs over a five-year period (2019-2023). Based upon the information I am accepting the Company's adjustment of $3,480,000.

Q. WHAT IS YOUR TOTAL ADJUSTMENT TO THE COMPANY'S CUSTOMER SERVICE AND INFORMATION?

A. As shown on my Schedule DM-15, I am accepting the Company's Customer Information balance of $13,864,000.

h. <u>Sales Expense</u>

Q. WHAT DID THE COMPANY PROPOSE RELATED TO ITS SALES EXPENSE?

A. The Company proposed a total Sales expense of $1,738,000 as shown on Company Schedule D-2. The only adjustment to this expense is related to Salary and Wages of $13,000 as shown on Company Schedule D-7.

1. <u>Salary and Wages (Schedule D-6 and 7) $13,000</u>

Q. HOW DID THE COMPANY DEVELOP ITS SALARY AND WAGE ADJUSTMENT OF $13,000 RELATED TO SALES EXPENSE?

A. As more fully explained previously in my testimony, this balance reflects a 3.00% wage increase for unionized, exempt and non-exempt employees to reflect the end of the FPFTY operating conditions and annualizes payroll expense among the various cost accounts. (Statement No. 2 at 17).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S $13,000 ADJUSTMENT TO SALARY & WAGES?

A. As I indicated previously in my testimony, I am accepting the Company's 3% wage increase of $16,000.

Q. WHAT OTHER ADJUSTMENTS HAVE YOU MADE RELATED TO SALES EXPENSE?

A. I have two adjustments. My first adjustment is related to the Company's Advertising Expenses balance of $1,901,541 shown on Company's Schedule 53.53 Attachment III-25. Included in the Company's proposed Advertising balance are costs of $885,178 related to Other Advertising Expense for Print/Digital, Radio, TV, Bill Insert and Other (mass media, website and branded giveaways). In response to I&E-RE-31, the Company provided a breakdown of these costs. These costs related to Sponsorships, Trade Shows, Branded Promotions, Customer Service Promotions and Miscellaneous Advertising. I am recommending that these costs be removed as they are not related to any useful advertising expense or institutional or instructional advertising which benefits customers. I believe these types of costs and Advertising expenses are pitched toward Company branding, recognition, and being good corporate citizens. My second adjustment is related to Conservation Advertising of $659,827. In response to I&E-RE-31, the Company stated that the variance between the HTY and FPFTY resulted from the resumption of normal activities in print and digital channel advertising related to Conservation of Energy which help customers reduce energy consumption. The Company proposed a FPFTY period balance of $659,827 (Attachment III-25). These costs increased over 70% from the FY 2021. I am normalizing these costs over three-years to arrive at a balance reduction of $193,114, or a normalized balance of $466,713. The Company did not record any costs to this account in FY 2019 and recorded $382,884 for FY 2020 and $376,148 in FY 2021. In my opinion, the costs incurred in FY 2020 and FY 2021 reflect a normal level of costs for this category. The Company has not justified the 70% increase over the FY 2022 and FY 2023 balance, and therefore, a normalized level is appropriate. My adjustments are shown on my Schedule DM-16.

i. <u>Administrative & General (A&G) Operations and Maintenance Expense</u>

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS ADMINISTRATIVE & GENERAL EXPENSES?

A. The Company proposed a beginning balance of its A&G Expenses of $116.044 million and added $12.313 million of adjustments to arrive at a FPFTY balance of $128.357 million. The Company proposed six specific adjustments. These adjustments are broken down as follows: (1) Salary and Wages $330,000; (2) Environmental Adjustments $2,327,000; (3) Rate Case Expenses $55,000; (4) OSHA-ETS Compliance Costs of $1,692,000 and one-time cost of $191,000; (5) Benefits Adjustments $8,387,000 and; (6) Other Adjustments - Injury and Damages of ($670,000). I will discuss each of these adjustments below:

1. <u>Salary and Wages (Schedule D-6 & 7) $330,000</u>

Q. HOW DID THE COMPANY DEVELOP ITS ADJUSTMENT TO ITS SALARY & WAGES OF $330,000?

A. The Company adjusted its salaries and wages to reflect end of FPFTY operating conditions. The adjustment annualized payroll expense and it is distributed among the various costs accounts. (Statement No. 2 at 17). The Company increased its A&G operation salaries by $309,000 and its maintenance salaries by $21,000. These increases represent a 3.00% wage increase for unionized, exempt and non-exempt employees to reflect the end of the FPFTY operating conditions and to annualize payroll expense among the various cost accounts.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S BALANCE OF $3,172,000?

A. As I indicated previously in my testimony, I am accepting the Company's 3% wage increase of to reflect an adjustment of $330,000.

2. <u>Environmental Adjustments #3 (Schedule D-8) $2,327,000</u>

Q. WHAT HAS THE COMPANY INCLUDED REGARDING ENVIRONMENTAL ADJUSTMENTS?

A. The Company has included an adjustment of $2,327,000 related to the Company's under-recovery of its manufactured gas plant (MGP) remediation expense incurred since the last rate case by comparing the actual Fiscal Year 2020 and 2021 remediation costs with the normalized level authorized in the 2019 and 2020 base rate cases, respectively. (Statement No. 3 at 18). The Company proposed the $2,327,000 be recovered over a one-year amortization period through Fiscal Year 2023. In response to Confidential I&E-RE-44 **(Begin Highly Confidential),** the Company stated that the one-year amortization period was chosen because the Company believes it is a reasonable period between rate cases. **(End Highly Confidential)**.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I am recommending this adjustment be amortized over a five-year period consistent with how the Company's other Environmental Adjustments (Adjustment No. 2 Company Schedule D-8) are being amortized. I believe that consistency among the various Environmental Adjustments periods is appropriate as it further normalizes these costs.

Given the ongoing annual cash expenditures and the Company's annual rate case filings, it is appropriate to normalize these costs over a longer period of time.

3. Rate Case Expenses (Schedule D-10) $55,000

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO RATE CASE EXPENSES?

A. The Company has proposed a total rate case expense of $1,055,000. The Company began by included a budgeted amount related to rate case expenses of $1,000,000 and added a pro-forma adjustment of $55,000 to arrive at a rate case balance of $1,055,000.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S $1,055,000 RATE CASE EXPENSE RECOVERY?

A. The first adjustment that I am recommending is to the amortization period the Company is proposing. I believe that these costs should not be amortized over a one-year period, but instead they should be normalized, and they should be based upon the Company's actual prior rate case expense filings. As shown in response to OCA-III-16 the Company has filed the following base rate case proceedings, including this instant proceeding, along with the associated actual rate case expenses incurred in those proceedings:

R-2021-3030218	$1,055,000
R-2019-3015162	$1,050,932
R-2018-3006814	$ 859,194
R-2016-2580030	$ 576,127
R-2015-2518438	$1,077,315
R-2010-2214415	$ 643,687
Total	$5,262,255

Q. HOW DOES THE COMMISSION ACCOUNT FOR RATE CASE EXPENSES?

A. First, the Commission routinely normalizes, not amortizes rate case expense. It then looks to the historical filing frequency to determine the proper normalization period. I am extending the rate case normalization period to a 2-year normalization period, based upon the Company's historical rate case filings. The earliest rate case was filed in January 2010 and the most recent rate case was filed in January 2022, a twelve-year period. During those periods the Company filed Historical rate case filings calculate to an average time span of 2 years. A 2-year normalization period would result in an annual recovery balance of \$527,500, (\$1,055,000 / 2 years) a reduction of \$527,500 from the Company proposed balance of \$1,055,000. My adjustment is shown on my Schedule DM-17. Line 28.

4. OSHA Emergency Temporary Standard (ETS) Compliance Costs (Schedule D-13) \$1,883,000

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO OSHA ETS COMPLIANCE COSTS?

A. As shown on Company Schedule D-13, the Company proposed ongoing costs related to tracking and testing with respect to COVID-19 and to remaining in compliance with the recently issued Federal requirement. (Statement No. 3 at 24). Ms. Ressler stated that the Company is prepared to comply with President Biden's COVID-19 action plan and the Department of Labor OSHA Emergency Temporary Standard requirements related to vaccination and test mandates. The Company proposed recovery of \$1.692 million which included a subscription for software to track vaccination status and the costs to perform COVID-19 testing, and a one-time cost of \$191,000 related to communication and legal advice (Company Schedule D-13). The Company proposed to recover these costs over a one-year period. Ms. Ressler stated that depending on the outcome of the Federal Mandate, the Company can reassess to determine whether this figure should be further adjusted or if a regulatory asset should be created. (Statement No. 3 at 25).

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S OSHA ETS COMPLIANCE COSTS?

A. In response to OCA-III-25, the Company stated that since it finalized its preparation of the revenue requirement claim, the U.S. Supreme Court overturned the Federal Mandate for vaccination and testing requirements, and since it is likely that there will not be a similar mandate passed the Company has withdrawn substantially all of its claim, but for certain costs incurred with legal advice in the amount of \$52,934. The Company stated that it will maintain its claim to amortize this \$52,934 cost over a one-year period. I am recommending removing all of the legal advice and communications costs including the amount the Company has incurred to date of $52,934. Given that the Federal Mandate has not passed, these legal costs are moot, and ratepayers should not be required to absorb these costs. My adjustment is shown on my Schedule DM-17 Line 33.

5. <u>Benefits Adjustments (Schedule D-14) $8,388,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS BENEFITS ADJUSTMENTS?

A. The Company has proposed a Benefits adjustment of $8,388,000 as shown on Company Schedule D-14. Company witness Ms. Ressler stated that the adjustment related to Pension Expense reflects the adjustment from budgeted pension expense for cash to be contributed to the plan in the FPFTY. This was based on generally accepted accounting principles (GAAP) requirements to reflect service and non-service costs based upon assumptions. (Statement No. 3 at 21). Ms. Ressler stated that consistent with prior ratemaking practices, the Company claims pension costs within its rates on a cash basis. The adjustment is calculated using total cash contributions (per the Company's most recent actuarial report). It is then reduced to reflect only the portion attributable to UGI Gas, and then further reduced to reflect the portion of pension that is capitalized. The cash pension expense of $5.501 million is compared to the budgeted pension income of $2.887 million resulting in an adjustment of $8.388 million. (Statement No. 3 at 21-22). As stated in response to Confidential OCA-III-22 **(Begin Confidential)** the total cash contributions of $11,364,000 are determined by the Company's actuarial firm and since contributions are calculated only one year in advance, the Company assumed that contributions will be consistent from FY 22 to FY 23. **(End Confidential).**

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I reviewed the response to OCA-VII-3, which shows the Pension Expense and Cash Contributions for the periods September 30, 2018 through September 30, 2022. The Company's pension expense shows variability from a high expense of $6.417 million to a budgeted income balance of $2.887 million, while the cash contributions attributable to UGI Gas have been fairly stable and consistent during the same years. Given this variability and the fact that pension plans can vary considerably over time depending on changes in the estimated costs, I am recommending normalizing the pension expense over a three-year period 2019-2021. This adjustment reduces the cash contribution and the proposed adjustment from $8,388,000 to $2,429,133, a difference of $5,958,667. My adjustment is shown on my Schedule DM-17.

6. <u>Other Adjustments Injury & Damages (I&D) (Schedule D-15) $670,000</u>

Q. WHAT HAS THE COMPANY PROPOSED WITH REGARD TO OTHER ADJUSTMENTS?

A. The Company has proposed an adjustment to its I&D of $670,000. The Company calculated a three-year average of I&D costs for the periods 2019-2021 and normalized these costs to arrive at a decrease of $670,000, from the Company budgeted balance of $2.023 million. This is shown on Company Schedule D-15.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S I&D ADJUSTMENT?

A. No. I am accepting the Company's adjustment of $670,000 relating to I&D.

Q. ARE THERE ANY OTHER ADJUSTMENTS THAT THE COMPANY INCLUDED IN ITS A&G EXPENSES?

A. Yes.

Q. WHAT OTHER ADJUSTMENTS DID THE COMPANY INCLUDE?

A. The Company has the following adjustments related to the Company's A&G Expenses:

- Company Membership adjustments of $1,115,404 (SDR-RR-30)
- Employee Activity of $588,226 (I&E-RE-24)
- Sponsorships of $424,000 **–** (I&E-RE-22)
- Corporate allocation costs adjustment of (**Begin Confidential)** $6,213,000 **(End Confidential)** in OCA-III-15, and I&E-RE-17 (Confidential)

- UGI Incentive Compensation of **(Begin Confidential)** $2,312,000 Stock Awards, Executive Bonus, Restricted Stock Awards, Stock Options, and Deferred Compensation (SERP) **(End Confidential).** See response to Confidential I&E-RE-17.
- Management Incentive Plan – (**Begin Confidential)** ($2,603,000 **(End Confidential)**. See Confidential I&E-RE-17.
- Outside Contractors of $1,383,000 - (OCA-III-33)
- Employee Benefits of $9,506,494 – Account 926 – (I&E-RE-28)
- Employee Social and Corporate Governance (**Begin Confidential)** ($115,094) **(End Confidential) Highly Confidential** OCA-X-1

Q. WHAT HAS THE COMPANY INCLUDED REGARDING MEMBERSHIP COSTS?

A. In response to I&E-RE-20 and Attachment SDR-RR-30, the Company has included approximately $1.1 million of Company Membership fees for the FY 2023. These costs include various fees related to Economic Development, Gas Associations, Consortiums, Collaboratives, Alliances, Economic Leagues, and other organizations.

Q. WHAT ADJUSTMENT DO YOU HAVE WITH RESPECT TO THE COMPANY'S MEMBERSHIP COSTS?

A. I reviewed the response to I&E-RE-20 and Attachment SDR-RR-30 and determined that certain of these membership costs relate to organizations, chambers of commerce, alliances, economic development, and other consortiums that in my opinion do not benefit Company ratepayers or relate to the provision of safe and reliable gas utility service. 66 Pa.C.S. Section 1316.1 regarding the recovery of club dues states that "no public utility may charge to its customers as a permissible operating expense for ratemaking purposes membership fees, dues or charges to fraternal, social or sports club or organizations." Certain of these membership dues mainly benefit the Company by contributing to its ability to be a good corporate citizen, providing advocacy on policy issues before State and Governmental agencies, and aiding in civic related initiatives. I am recommending that only the following Membership Fees be included in the Company's A&G Expense categories: (1) American Gas Association - $621,015 (less $23,599 related to Lobbying)[14] and: (2) Northeast Gas Association - $55,000 for a total of $652,416, a reduction of $540,912 from the Company's balance of $1,115,404. The remaining Membership Fees, in my opinion do not comport to costs associated with Company memberships that provide benefits to the ratepayers of UGI-Gas that relate to safety, reliability and adequacy of service. My adjustment is shown on my Schedule D-17 as a reduction of $540,912.

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO EMPLOYEE ACTIVITIES?

A. The Company has proposed to include costs related to Employee activities of $588,276 as shown in response to I&E-RE-24. These costs relate to Company picnic, Service Awards, Annual Holiday breakfast, and Other activities.

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S EMPLOYEE ACTIVITIES?

A. I believe that these costs should be removed for ratemaking purposes. In my opinion, these costs do not provide any benefits to ratepayers. I do not believe that ratepayers should pay for costs related to non-utility expenses and for special activities outside the employees' normal business working hours, nor for costs related to flowers and cards. As I stated previously under Membership Fees, ratepayers do not receive any benefit related to safe, reliable and adequate utility service for these expenses. My adjustment is a reduction of $588,226 as shown on my Schedule DM-17.

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS SPONSORSHIPS?

A. In response to I&E-RE-22 the Company provide a schedule that shows a breakdown of Sponsorships and Members of $424,000. This balance is also shown on Attachment III-A-28.1. These costs reflect payments to Costs for Kids, American Red Cross, Sound the Alarm, Honor Roll, United Way Day of Caring and other social and sponsoring events.

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S SPONSORSHIPS?

[14] The Company also included $9,259 of Lobbying activities in Energy Association of Pennsylvania.

A. I am of the opinion that these costs do not provide any benefit to ratepayers in the form of safe, reliable and adequate utility service, and therefore, these costs should be removed from the Company revenue requirement proposal. These costs, mainly benefit the Company as stated above by contributing to its good corporate citizenship. My adjustment of $424,000 is shown on my Schedule DM-17.

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CORPORATE ALLOCATION COSTS?

A. In response to Confidential I&E-RE-17, the Company proposed total Corporate Allocation Costs of **(Begin Confidential)** $6,213,000. These costs relate to allocated costs from UGI Corporation for (1) Incentive Compensation of $1,364,000; (2) Stock Compensation and Restricted Stock Awards of $3,319,000; (3) Directors' Equity Compensation of $555,000; (4) Shared Executives Incentive Compensation of $512,000; (5) Stock Options and Restricted Stock Awards of $1,153,000 and; (6) Direct Cost to Utilities – Incentive Compensation of $309,000. **(End Confidential).**

Q. HAS THE COMPANY PROVIDE ANY DOCUMENTATION OR SUPPORT TO DESCRIBE WHAT THE COMPANY ENTITLES AS ITS UNITE INCENTIVE COMPENSATION PLAN?

A. Yes. In response to I&E-RE-17.3 (Confidential), **(Begin Confidential)** the Company provided a document that describes the Company's Incentive Plan. The Company refers to its UNITE incentive compensation plan as the "Project Milestone Incentive Plan" (Project Milestone). The Project Milestone is designed to recognize, and reward dedicated and committed Project Team members who meet or exceed the goals, expectations, and timelines created for the EAM phase of UNITE. Payout will be determined based upon progress levels achieved versus baseline objectives and key project milestones. Payout is achieved based upon completion of critical project milestones that are met within 2 weeks of the planned target delivery date. A more detailed description is shown on Confidential Attachment I&E-RE-17.3. The UNITE Milestone Incentive Compensation Plan has a weight of 100% with a goal of UNITE ADC Project Execution, with a 90% of phase deliveries delivered within 2 weeks of planned Phase end date given no risk to Go-Live. In response to I&E-RE-17.4, the Company provided its UNITE Enterprise Asset Management (EAM) and Asset Data Collection (ADC) Project document and Incentive Plan for Project

Leadership Roles and Core Team Roles. The Company stated that the purpose of this Incentive Plan is to recognize and reward the dedicated and committed Program Team Members whose primary work focus will be working on multiple discrete projects under the Program and meeting the goals, expectations and timelines set forth to ensure successful outcomes. A more detailed description is shown on Confidential Attachment I&E-RE-17.4. The goal of the plan is to reward effective performance in three areas: project budget, project scope, and project execution. These three areas are weighted as follows: 25% is weighed to Project Cost Management with <105% of budget; 25% is related to Scope Management with <7% from target baseline; and 50% for Project Execution with 90% of phase deliverables delivered within 2 weeks of planned Phase end date, given no risk to Go-Live. In responses to OCA-XI-I (Confidential) – the Company stated that the incentive compensation costs do not include incentive compensation related to the UNITE compensation and all incentive compensation as these are capitalized and not included in expenses. Therefore, it is my understanding that the Incentive Compensation costs shown in the response to I&E-RE-17.2 do not include expenses related to the UNITE Initiative and do not affect all other incentive compensation. These costs are for the Company's Asset Data Collection (ADC) project, which is expected to go into service for UGI Gas in January 2023. **(End Confidential).**

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S CORPORATE ALLOCATION OF (BEGIN CONFIDENTIAL) $6,213,000? (END CONFIDENTIAL)

A. I am recommending removal of these costs from rates. According to the response to OCA-Set XI-1 (**Begin Confidential)** these costs are budgeted at an expected 100% payout. The anticipated payout date for the UNITE ADC is no later than April 30, 2023, with an expected notification date of two weeks prior. I believe these costs are uncertain and speculative because in response to I&E-RE-17.4, the Company indicated that the incentive will be paid once the Executive Committee reviews the effectiveness of the project and this will determine the timing of incentive payout. The incentive will not be paid immediately at the project conclusion, but it will be paid no later than the conclusion of the ADC project -defined Gas Hypercare period. Compensation will be prorated based on the time contributed to each milestone deliverable and subject to the discretion of the UGI

Leadership. **(End Confidential).** There are a lot of variables for receipt of the incentive compensation and based upon the timing of the payout the costs are not known and measurable.

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO UGI MANAGEMENT INCENTIVE COMPENSATION?

A. As shown on Confidential Attachment I&E-RE-17.2 the Company proposed a total Management Incentive Plan cost of **(Begin Confidential)** $4,916,000 broken down by the following: (1) Management Incentive Plan of $2,603,000; (2) Executive Bonuses of $714,000; (3) Restricted Stock Awards of $766,000; (4) Stock Options of $401,000 and: (5) Deferred Compensation Supplemental Executive Retirement Plan of $431,000. These costs total $2,312,000. **(End Confidential).**

Q. DID THE COMPANY PROVIDE ANY DOCUMENTATION TO SUPPORT THE LEVEL OF ITS MANAGEMENT INCENTIVE PLAN?

A. Yes, in response to I&E-RE-18, the Company provided a detailed explanation of how these budgeted amounts were calculated. The Company calculated total Incentive Compensation of $11,129,787 which is broken down by the total UGI Utilities portion of **(Begin Confidential)** of $4,916,000 and that which was allocated from UGI Corporation of $6,213,000 (See I&E-RE 17.2). **(End Confidential).**

Q. PLEASE BRIEFLY DESCRIBE EACH OF THE COMPANY'S INCENTIVE COMPENSATION COSTS INCLUDED IN THE FILING?

A. The budget for the Management Incentive Plan of **(Begin Confidential)** $2,603,000 **(End Confidential)** was calculated for eligible employees using their salaries, position grade, and payout percentage assuming 100% payout per the UGI Utilities Inc. Management Incentive Plan and allocated using their payroll O&M and capital split. The budget for the Executive Bonus Plan of **(Begin Confidential)** $714,000 **(End Confidential)** was calculated for eligible employees using their salary and payout per UGI Utilities Executive Annual Bonus Plan assuming a 100% payout. The Performance Restricted Stock Awards of **(Begin Confidential)** of $766,000 **(End Confidential)** in part, were budgeted using a Monte-Carlo simulation prepared by Willis Towers Watson. The equity portion is set at grant date and amortized equally over three-years. Expense is accelerated for awards that are subject to retirement eligibility provisions. Assumptions are made about future stock prices to estimated marked to market expense/credits. For awards not yet granted, stock price assumptions and historical data are used to calculate an assumed Monte-Carlo valuation and the split of the expense between the equity and liability portions is assumed based upon historical data. The budgeted expense related to Stock Options of **(Begin Confidential)** $401,000 **(End Confidential)** is based in part upon a combination of those awards that have already been granted and those not yet granted. The full cost of the award (calculated using a black-scholes formula) is amortized over a 3-year period. The award is front loaded for those retirement-eligible employees over the first six months from the award date. Finally the Supplement Executive Retirement Plan (SERP) of **(Begin Confidential)** $431,000 **(End Confidential)** is made up in part from a calculation of two plans: the Defined Benefits SERP and the Defined Contribution SERP. The participants in the Defined Benefits SERP are also participants in the Company's pension plan, therefore the annual benefit calculation is an actuarial one done by Willis Towers Watson. For the Defined Contribution SERP, the budget is prepared by doing a calculation of what would be the executive's SERP Benefits for the following fiscal year based upon the executive's current salary plus a 3% merit increase.

Q. DID THE COMPANY PROVIDE RESULTS RELATED TO THE UNITE MANAGEMENT INCENTIVE PLAN BUDGET OF (BEGIN CONFIDENTIAL) $2,603,000 (END CONFIDENTIAL)?

A. In response to Confidential OCA-XI-I, I asked the Company to provide the expected notification dates, pay out dates, dollar amounts of each UNITE goal and whether the targeted goals and performance metrics were met. As stated earlier in my testimony, the only incentive compensation that is included in the expenses is (**Begin Confidential**) for the ADC project which is expected to go into service in January 2023 (**End Confidential**).

Q. WHAT ARE YOUR ADJUSTMENTS?

A. As indicated previously under my adjustments to the Company's Corporate Allocation expenses of (**Begin Confidential)** of $6,213,000,(**End Confidential)** I am recommending removal of these costs from rates. According to the response to OCA-Set XI-1 (**Begin Confidential)** these costs are budgeted at an expected 100% payout. The anticipated payout date for the UNITE ADC is no later than April 30, 2023 with an expected notification date of two weeks prior. I believe these costs are uncertain and speculative because in response to I&E-RE-17.4, , the Company indicated that the incentive will be paid once the Executive Committee reviews the effectiveness of the project and this will determine the timing of incentive payout. The incentive will not be paid immediately at the project conclusion, it will be paid but no later than the conclusion of the ADC project - defined Gas Hypercare period. Compensation will be prorated based on the time contributed to each milestone deliverable and subject to the discretion of the UGI Leadership. **(End Confidential).** There are a lot of variables for receipt of the incentive compensation and based upon the timing of the payout the costs are not known and measurable.

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S INCENTIVE COMPENSATION OF (BEGIN CONFIDENTIAL) $2,312,000 (END CONFIDENTIAL)?

A. These costs should not be included in the Company's projected expenses, as these are related to Executive Compensation currently employed by the Company and executives who have retired from the Company, and I believe that these costs do not provide benefits to customers in the area of customer service, customer satisfaction, customer engagement or safety and reliability issues. As indicated in response to I&E-RE-18, these costs are linked to future stock prices and stock price assumptions. I do not see any ratepayer benefit related to these Executive Bonus Plans, Performance Restricted Stock Awards, or payments to Executive Retirement Plans for those Executives who have retired.

Q. WHAT ARE YOUR OTHER ADJUSTMENTS WITH RESPECT TO THE COMPANY'S A&G EXPENSES?

A. As I normalized the Company's Outside Contractors Expenses under Distribution and Customer Accounts Expense, I am normalizing these costs under the Company's A&G Expenses, to be consistent in my normalization. The Company proposed an Outside Contractor Expense of $1.383 million under the FPFTY period in response to OCA-Set III-33. The Company provided a breakdown of its Outside Contractors Expenses for the periods 2019 through the FPFTY. These costs are mainly related to contractor labor and specifically for the categories of other, restoration, pipeline and traffic removal.

Normalizing these costs by averaging out the expenses over a three-year period (2020-2022) results in a decrease of about $23,000. These types of costs do fluctuate over time because they are outside the control of the Company, they are volatile in nature and are unpredictable.

Q. WHAT IS YOUR NEXT ADJUSTMENT TO THE COMPANY'S A&G EXPENSES?

A. My final adjustment to the Company's A&G Expenses is related to the Company's Employee Benefits costs for which the Company has proposed a balance of $9,506,494 (net of capitalized costs of 40%). These costs are accounted for in Account No. 926.

Q. WHAT REASONS DID THE COMPANY PROVIDE WITH RESPECT TO ITS ADJUSTMENTS TO EMPLOYEE BENEFITS INCLUDING MEDICAL AND DENTAL PLAN COSTS?

A. The Company stated that it budgeted these Dental costs using three-months of data (Oct-Dec) of prior year budget to reflect calendar year enrollment and the remaining nine-months (Jan-Sept) of budget were calculated using four-months of claim costs as well as a 7% increase provided by its broker Willis Towers Watson (WTW) taken from a national medical/Rx carrier survey, and a 2% expected increase in enrollment for the FPFTY. (I&E-RE-28). The Company budgeted using similar methods for Medical costs and utilized an 8% increase to factor in medical claims costs, and an additional 8% increase added on top of other budget increases to account for higher head count and expected higher costs in part due to elective medical procedures, which were deferred during the COVID-19 pandemic timeframe.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL AND ADJUSTMENTS TO ITS MEDICAL AND DENTAL PLAN COSTS?

A. I am not in agreement with the Company's reliance upon national surveys, as these results can vary, are subject to interpretation, and can result in changes based upon which provider is preparing the surveys. I understand that medical and dental costs are increasing over time, however, situations have changed with respect to medical costs and medical coverages. In a Post-COVID-19 environment, some companies have switched to a hybrid workplace, allowing more employees to work remotely which may provide for reduced employee costs. Teleworking or telecommuting can reduce stress on employees that need to balance work/family life, and in turn can increase the quality of life. By reducing commute time and costs, employees can become more engaged in their work by providing for less stressful day-to-day situations if carefully monitored. I believe there is a marketplace for the Company to explore more affordable options for health care based on savings gained from moving to these hybrid workplace models and there are varying opinions on health policy that can affect the cost of coverage. In addition, the Company has included a 7% increase, and a 2% increase for Dental costs, which may not be realized. The same holds true for Medical costs adjustment of 8% and an additional 8% for expected higher costs which also may not be realized.

Q. WHAT ARE YOU RECOMMENDING?

A. I am recommending normalizing the Company's Medical and Dental costs over the FY 2021-2023 period, which when averaged out reduces the costs from $9,506,494 to $8,469,460, a reduction of $1,037,034. This also takes into consideration my recommended reduction of employee count (open positions) in the FPFTY period. The Company has not prepared its claims for Medical and Dental costs based primarily on anticipated eligible participants and the information is not available for the FTY and FPFTY periods. (I&E-RE-28). The Company booked $6.796 million of Medical and Dental costs in FY 2020 and $9.506 million of Medical and Dental costs in FY 2023, an increase of almost 40%. Normalizing these costs over three periods results in an increase of $1.673 million over FY 2020, a 25% increase.

Q. WHAT IS YOUR FINAL ADJUSTMENT RELATED TO THE COMPANY'S A&G EXPENSES?

A. My final adjustment is related to the Company's Breakdown of Corporate Allocation in response to I&E-RE-3 Attachment 3.2 – Corporate Allocation. In Attachment OCA-X-1 (Highly Confidential) the Company provided a breakdown for Professional Expenses **(Begin Confidential)** at the cost center level at UGI Corporation. In reviewing this response I identified costs related to Environmental, Social and Governance (ESG) costs amounting to $453,900 (Cost Center 436) and for Company Membership dues amounting to $38,760. (Cost Center 436). These costs relate to the corporate social goals of maximizing profits on behalf of the corporation's shareholders and advocating a certain set of environmental goals. The costs also related to the Company's support for certain social movements along with the diversity, equity and inclusion movement. **(End Confidential)** I believe these costs should not be recovered from ratepayers as they do not support the safe, reliable and adequate service requirement of utility service but rather the costs are akin to sponsorships and civic related activities. These costs should be borne by the Company shareholders. **(Begin Confidential)** The allocated costs to the UGI-Gas Division using the Company's allocation factors of 25.76% and 90.69% (Attachment I&E-RE-3.2) equal a balance of ($453,900 times 25.76% times 90.69%) $106,039. For the Membership dues of $38,760 the allocation to the UGI-Gas Division is $9,055. The total adjustment is $115,094. **(End Confidential).**

Q. WHAT IS YOUR OVERALL ADJUSTMENT TO THE COMPANY'S A&G EXPENSE?

A. My overall adjustment to the Company's A&G Expenses is a reduction of $22,747,366 shown on my Schedule DM-17.

3. <u>DEPRECIATION EXPENSE</u>

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS DEPRECIATION EXPENSE?

A. The Company proposed a Depreciation Expense of $125.537 million as shown on Company Schedule D-2 and Schedule D-21. The Company began with the annual depreciation for gas distribution plant and common plant as budgeted during the 9/30/2023 period and allocated a portion of the common plant to the gas division of $127.823 million. The Company annualized budgeted FPFTY depreciation expense to calculate an entire year's worth of depreciation on plant in service as of the end of the FY 2023. The Company made adjustments to charges to Clearing Accounts of $8.371 million and the Company made an adjustment to Net Salvage Amortization of $6.083 million to arrive at a balance of $125.537 million. (Company Schedule D-21). The Company's claim for depreciation expense is based on a straight line remaining life method of depreciation. (Statement No. 4 at 12). The Company's claim for depreciation is in connection with the Company's submission of its annual depreciation report which is approved each March by the Commission. (Statement No. 4 at 14).

Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO THE COMPANY'S DEPRECIATION EXPENSE?

A. I am accepting the Company's service lives and depreciation rates. My adjustments relate to my disallowance of a certain plant that was included in the Company's GPIS balance.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S NEGATIVE NET SALVAGE VALUE BALANCE?

A. No.

Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S DEPRECIATION EXPENSE?

A. Since I removed certain projects from the Company's FY 2022 and FY 2023 plant additions, I am removing the associated Depreciation Expense. Using the Company's composite rate of depreciation for Distribution Plant of 2.06% and General Plant of 5.710%, my adjustments are $212,111 and $4,304,502, respectively, for a total adjustment of $4,517,363. [15]

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS TO THE COMPANY'S DEPRECIATION EXPENSE?

A. No.

4. TAXES OTHER THAN INCOME

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO TAXES OTHER THAN INCOME TAXES?

A. The Company proposed total Taxes Other than Income in the amount of $13.658 million as shown on Company Schedule D-2 and Schedule D-31. The Company included taxes associated with payroll taxes, PURTA taxes, PA & Local Use taxes, and the PUC assessment.

[15] Any differences are due to rounding.

Q. WHAT ARE YOUR ADJUSTMENTS AND YOUR RECOMMENDED LEVEL OF TAXES OTHER THAN INCOME TAXES?

A. I am accepting the Company's methodology in the calculation of its Taxes Other Than Income. I am making adjustments to the Company's Payroll Taxes that reflect my recommended S&W balance, which includes my adjustments to the Company's open positions and my adjustments to the Company's various Incentive Compensation costs. I removed costs associated with certain Incentive Compensation adjustments, which are reflected in the Company's payroll rates accordingly. My adjustment is a reduction of $515,314 from the Company's proposed balance of $13,658,307 or $13,142,993.

Q. WHAT IS YOUR OTHER ADJUSTMENT TO TAXES OTHER THAN INCOME?

A. I adjusted the Company's PA & Local taxes in response to OCA-Set III-18, in which the Company overstated its claim in the amount **(Begin Confidential)** of approximately $77,000. (**End Confidential)** (Attachment OCA-III 18(2)).

5. INCOME TAXES

Q. WHAT DID THE COMPANY CALCULATE WITH RESPECT TO ITS INCOME TAXES?

A. The Company proposed total Income Taxes of $63.348 million, of which $15.523 million is related to the State Income Taxes and $47.824 million is related to the Federal Income Taxes as shown on Company Schedule D-33.

Q. WHAT OTHER ADJUSTMENTS DID THE COMPANY MAKE TO COMPUTE ITS INCOME TAX EXPENSE?

A. According to Ms. McKinney, the Company included the use of debt interest synchronization, the normalization method for accelerated depreciation and the flow-through of accelerated depreciation benefits for state tax purposes. (Statement No. 7 at 5). The Company continued to flow through the repairs tax benefit over the tax useful lives of the asset that generate the tax benefit which is generally 20 years. (Statement No. 7 at 5).

Q. DID THE COMPANY INCLUDE ADJUSTMENTS RELATED TO THE EXCESS DEFERRED FEDERAL INCOME TAXES AS A RESULT OF THE 2017 TAX CUTS AND JOBS ACT (TCJA)?

A. Yes. Company witness Ms. McKinney stated that the Excess Deferred Federal Income Taxes (EDFIT) has been calculated, amortized and flowed-back to ratepayers in the FPFTY period. The amount of the EDFIT has been calculated at $17.702 million (Company Schedule D-33 line 25) and the total amortization is approximately $4.3 million using the average rate assumption method (ARAM) as required by tax normalization rules. (Statement No. 7 at 6).

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S METHODOLOGY WITH RESPECT TO THE CALCULATION OF THE COMPANY'S INCOME TAXES?

A. No I am accepting the Company's methodology. My adjustments reflect the recommended changes of Rate Base and Operating Income.

Q. WHAT ARE YOUR RECOMMENDED FEDERAL INCOME TAXES AND RECOMMENDED STATE INCOME TAXES AT PRESENT RATE REVENUE?

A. My recommended Federal Income Taxes is $37,748,730. My recommended State Income Taxes is $9,769,753

Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE COMPANY'S INTEREST EXPENSE CALCULATION?

A. Using my recommended Rate Base Balance of $3.087 billion and Mr. Garrett's recommended Long-Term Debt Ratio of 50% and cost of debt of 1.990%, my recommended Interest Expense is $61,437,244.

Q. WHAT IS YOUR TOTAL INCOME TAX EXPENSE AT PRESENT RATE REVENUE?

A. My total Income Tax Expense at Present Rate Revenue is $47,518,483. The additional revenue requirement adjustment is factored into Gross Revenue Conversion Factor shown on my Schedule DM-1.

D. Act 40 Requirements (Act 40 of 2016)

Q. WHAT ARE THE ACT 40 REQUIREMENTS?

A. Act 40 took effect on August 11, 2016, and among other things, it eliminated the consolidated tax savings adjustment. Prior to Act 40, the Company would have been required to adjust its revenue increase request downward to reflect tax savings associated with filing taxes as part of a parent or holding company. This practice recognized that the Company's ratepayers only paid through rates those taxes that the Company actually paid. Act 40 requires the Company to continue its performance of the consolidated tax savings calculation and provide that consolidated tax savings differential as part of its rate case filing. In part, Act 40 states:

> If an expense or investment is allowed to be included in a public utility's rates for ratemaking purposes, the related income tax deductions and credits shall also be included in the computation of current or deferred income tax expense to reduce rates. If an expense or investment is not allowed to be included in a public utility's rates, the related income tax deductions and credits, including tax losses of the public utility's parent or affiliated companies, shall not be included in the computation of income tax expense to reduce rates. The deferred income taxes used to determine the rate base of a public utility for ratemaking purposes shall be based solely on the tax deductions and credits received by the public utility and shall not include any deductions or credits generated by the expenses or investments of a public utility's parent or any affiliated entity. The income tax expense shall be computed using the statutory income tax rates.

Act 40 further states:

> REVENUE USE- If a differential accrues to a public utility resulting from applying the ratemaking methods employed by the commission prior to the effective date of subsection (a) for ratemaking purposes, the differential shall be used as follows:
>
> (1) Fifty percent to support reliability or infrastructure related to the rate-base eligible capital investment as determined by the commission; and
> (2) Fifty percent for general corporate purposes.

As a result, ratepayers now pay taxes in excess of those taxes that the Company actually pays, and the revenue use requirement specifies how those additional revenues are to be applied. Section 1301.1 (b) requires the Company to use 50% of that differential for reliability or infrastructure related capital investment and the remaining 50% for general corporate purposes.

Q. HAS THE COMPANY CALCULATED A CONSOLIDATED TAX EXPENSE ADJUSTMENT (CTA)?

A. According to Ms. McKinney, the Company has not calculated a CTA, because such an adjustment is no longer authorized under Section 1301.1 to the Public Utility Code, which eliminated the need to show a consolidated tax adjustment for ratemaking purposes. Section 1301 (b) required a public utility to demonstrate that it shall use at least 50 percent of what would have been a consolidate tax adjustment under the prior law to Act 40 for reliability or infrastructure related capital investments and the other 50 percent shall be used for general corporate purposes. (Statement No. 7 at 9).

Q. HAS THE COMPANY SATISFIED THE FIRST REQUIREMENT UNDER ACT 40 – 50% OF THE DIFFERENTIAL SPENT ON INFRASTRUCTURE REPLACEMENT?

A. Yes. As explained by Ms. Hazenstab, and as further discussed by Company witness Ms. Schappell, the Company's pro-forma capital additions for reliability or infrastructure projects for the FTY are $289 million and for the FPFTY are $311 million, which are greater than the 50% the Company calculated with respect to its consolidated tax savings of $2.553 million (Statement No. 2 at 26). (OCA-Set III-20).

Q. WHAT IS UGI'S PROPOSAL FOR THE OTHER 50% OF THE DIFFERENTIAL, WHICH SECTION 1301.1(b)(2) STATES MUST BE USED FOR "GENERAL CORPORATE PURPOSES"?

A. According to Ms. Hazenstab, the Company claimed that its general corporate purpose expense exceeded the 50% of the tax benefit that resulted from the elimination of the consolidated tax adjustment (Statement No. 2 at 27). Ms. Hazenstab stated that the Company's operating budget of more than $760 million in operating expenditures would be used to render gas distribution service. 50% of the consolidated tax adjustment would equate to only $1.825 million $1.277 million, plus the gross up of 1.429864 equals $1.825 million. (OCA-III-20).

Q. WHAT DO YOU CONCLUDE REGARDING THE 50% OF THE DIFFERENTIAL THAT ACT 40 REQUIRES TO BE USED FOR "GENERAL CORPORATE PURPOSES"?

A. UGI does not appear to propose a specific treatment for the other 50% of the differential, which Section 1301.1(b)(2) states must be used for "general corporate purposes." In response to OCA-III-20, I asked the Company to show how the 50% of the consolidated tax savings has been used for general corporate purposes. The Company responded that its operating expenses of more than $760 million exceed the Company's calculation of the 50% level of the adjustment related to general corporate purposes. UGI has identified no specific way in which that 50% of the differential would be used to benefit Pennsylvania ratepayers. One might conclude from this that UGI basically intends to use that money for the benefit of its stockholders, and not apply it in any manner to provide a quantifiable ratepayer benefit or in a manner that directly benefits service to Pennsylvania customers.

Q. WHAT DOES "GENERAL CORPORATE PURPOSES" AS USED IN ACT 40 MEAN?

A. Because UGI is a regulated utility in Pennsylvania, its "general corporate purpose" is to provide regulated utility service in the Commonwealth of Pennsylvania. While the term "general corporate purposes" is rather vague, general corporate purposes would typically include uses for such "differential" revenues as supporting capital expenditures necessary to execute utility business plans, paying off debt, funding construction projects, paying dividends, paying for maintenance and operating expenses, investing in utility plant in Pennsylvania, and providing a source of working capital. Many of these uses for "general corporate purposes" would have a quantifiable benefit to Pennsylvania ratepayers. As I read the entirety of Act 40, the "revenue use differential" addressed in the Act for "general corporate purposes" should mean public utility purposes and uses that result in having some identifiable and quantifiable benefit to Pennsylvania and UGI ratepayers, rather than just resulting in a windfall of $1.277 million annually to UGI's shareholders or affiliates.

Q. WHAT SPECIFIC RECOMMENDATION DO YOU HAVE IN THE CURRENT UGI GAS RATE CASE FOR APPLYING THE 50% OF THE "REVENUE USE" DIFFERENTIAL THAT ACT 40 REQUIRES TO BE FOR "GENERAL CORPORATE PURPOSES"?

A. I have reflected the 50% differential for general corporate purposes as a source of non-investor-supplied funding for utility working capital. I have reduced the Company's Rate Base balance by $1.277 million as shown on my Schedule DM-3.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

SUMMARY SCHEDULE

Measure of Value and Revenue Increase

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Rate Base	$ 3,169,023,000	$ (81,724,283)	$ 3,087,298,717	
2	Rate of Return	7.960%		6.240%	
3	Operating Income Requirement	$ 252,254,231	$ (59,606,791)	$ 192,647,440	
4	Present Rate Income	$ 194,387,000		$ 219,694,760	
5	Income Deficiency	$ 57,867,231	$ (84,914,551)	$ (27,047,320)	
6	Gross Revenue Conversion Factor (2)	1.429864		1.429864	
7	Revenue Requirement Increase	$ 82,742,270	$ (121,416,259)	$ (38,673,989)	

(1) Company Schedule A-1
(2) Company Schedule D-35

	Company Proposed	Adjustments	OCA Recommended	References
Gross Revenue Factor	1.000000		1.000000	
Uncollectible Expense	(0.016470)		(0.016470)	DM-14
	0.983530		0.983530	
State Income Taxes - 9.99%	0.098255		0.098255	
Factor After State Taxes	0.885275		0.885275	
Federal Income Taxes - 21.00%	0.185908		0.185908	
Net Operating Income Tax Factor	0.699368		0.699368	
Gross Revenue Conversion Factor	1.429863		1.429863	
difference due to rounding				

RATE OF RETURN

		Ratio	Cost Rate	Weighted Avg.
(1)	Company Proposed			
1	Long-Term Debt	44.880%	3.980%	1.79%
2	Short-Term Debt	0.000%	0.000%	0.000%
3	Common Equity	55.120%	11.200%	6.17%
4	**Total**	100.000%		7.960%
	OCA Recommended - (2)			
5	Long-Term Debt	50.000%	3.980%	1.990%
6	Short-Term Debt	0.000%	0.000%	0.000%
7	Common Equity	50.000%	8.500%	4.250%
8	**Total**	100.000%		6.240%

(1) Company Schedule B-7
(2) D. Garrett recommendation

MEASURE OF VALUE

Rate Base Valuation

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Gas Utility Plant In Service	$ 5,042,025,000	$ (85,681,967)	$ 4,956,343,033	OCA-Set X-2 I&E RB-4
2	Accumulated Depreciation	$ (1,318,560,000)	$ 4,516,613	$ (1,314,043,387)	
3	Net Gas Utility Plant In Service	$ 3,723,465,000	$ (81,165,354)	$ 3,642,299,646	
4	Working Capital Allowance	$ 62,148,000	$ (586,873)	$ 61,561,127	DM-7
5	Gas Inventory	$ 17,813,000	$ -	$ 17,813,000	
6	Customer Deposits	$ (21,600,000)	$ -	$ (21,600,000)	
7	Materials & Supplies	$ 15,707,000	$ -	$ 15,707,000	
8	Sub-Total	$ 11,920,000	$ -	$ 11,920,000	
9	Accumulated Deferred Income Taxes	$ (628,510,000)	$ 1,304,944	$ (627,205,056)	
	Consolidated Income Taxes	$ -	$ (1,277,000)	$ (1,277,000)	OCA-III-20
10	Total Measure of Value - Rate Base	$ 3,169,023,000	$ (81,724,283)	$ 3,087,298,717	

(1) Company Schedule C-1

	OPERATING INCOME STATEMENT	(1) Budget Year 9/30/2023	Adjustments	Company Proposed Proforma Present Rates	Adjustments	Proforma Proposed Rates	Adjustments	Present Rates OCA Recommended	References
	Operating Revenues								
1	Customer & Distribution Revenue	$ 602,316,000	$ 22,767,000	$ 625,083,000	$ -	$ 625,083,000		$ 625,083,000	
2	Gas Supply & Cost Adj. Revenue	$ 384,431,000	$ 42,923,000	$ 427,354,000	$ -	$ 427,354,000		$ 427,354,000	
3	Other Revenue	$ 9,939,000	$ 348,000	$ 10,287,000	$ -	$ 10,287,000	$ 413,667	$ 10,700,667	Sch D-2
4	Rate Increase	$ -	$ -	$ -	$ 82,742,000	$ 82,742,000		$ -	
5	Total Operating Revenues	$ 996,686,000	$ 66,038,000	$ 1,062,724,000	$ 82,742,000	$ 1,145,466,000		$ 1,063,137,667	OCA-VII-5
	Operating Expenses								
6	Gas Production	$ 14,000	$ 983,000	$ 997,000	$ -	$ 997,000	$ (43,400)	$ 953,600	DM-9
7	Gas Supply Production	$ 358,286,000	$ 38,877,000	$ 397,163,000	$ -	$ 397,163,000	$ -	$ 397,163,000	DM-10
8	Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
9	Distribution	$ 84,369,000	$ 3,853,000	$ 88,222,000	$ -	$ 88,222,000	$ (2,267,723)	$ 85,954,277	DM-12
10	Customer Accounts	$ 40,541,000	$ 1,829,000	$ 42,370,000	$ -	$ 42,370,000	$ (9,800)	$ 42,360,200	DM-13
11	Uncollectible Accounts	$ 14,419,000	$ 2,176,000	$ 16,595,000	$ 1,362,761	$ 17,958,000	$ (1,980,742)	$ 15,977,258	DM-14
12	Customer Information & Service	$ 10,368,000	$ 3,496,000	$ 13,864,000	$ -	$ 13,864,000	$ -	$ 13,864,000	DM-15
13	Sales	$ 1,725,000	$ 13,000	$ 1,738,000	$ -	$ 1,738,000	$ (1,078,292)	$ 659,708	DM-16
14	Administrative & General	$ 116,044,000	$ 12,313,000	$ 128,357,000	$ -	$ 128,357,000	$ (22,747,233)	$ 105,609,767	DM-17
	S&W adjustment - other overall - open position:	$ -	$ -	$ -		$ -	$ (779,368)	$ (779,368)	DM-11
15	Sub-Total	$ 625,766,000	$ 63,540,000	$ 689,306,000	$ 1,362,761	$ 690,669,000	$ (28,906,558)	$ 661,762,442	
16	Depreciation & Amortization	$ 128,358,000	$ (2,821,000)	$ 125,537,000	$ -	$ 125,537,000	$ (4,518,011)	$ 121,018,989	DM-17
17	Taxes Other Than Income Taxes	$ 13,360,000	$ 298,000	$ 13,658,000	$ -	$ 13,658,000	$ (515,007)	$ 13,142,993	DM-18
18	Total Operating Expenses	$ 767,484,000	$ 61,017,000	$ 828,501,000	$ 1,362,761	$ 829,864,000		$ 795,924,424	
19	Net Operating Income Before Income Taxes	$ 229,202,000	$ 5,021,000	$ 234,223,000	$ 81,379,239	$ 315,602,000		$ 267,213,243	
									Co. Sch D-33
20	Income Taxes - Present Rates	$ 38,384,000	$ -	$ 39,836,000	$ 23,512,000	$ 39,836,000		$ -	DM-19
21	Income Taxes - Revenue Increase					$ 23,512,000			
	Total Income Taxes	$ 38,384,000	$ 1,452,000	$ 39,836,000	$ 23,512,000	$ 63,348,000		$ 47,518,483	
22	Net Income	$ 190,818,000		$ 194,387,000	$ 57,867,239	$ 252,254,000		$ 219,694,760	
	check							$ (27,047,320)	
	Rate Base	$ 3,169,023,000		$ 3,169,023,000		$ 3,169,023,000		$ 3,087,298,717	
	Rate of Return	6.021%		6.134%		7.960%		6.240%	
	Check	$ 190,818,000		$ 194,387,000		$ 252,254,231		$ 192,647,440	

(1) Company Schedule D-1 D-2 and D-5

GAS UTILITY PLANT IN SERVICE

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Intangible Plant	$ 774,000		$ 774,000	
2	Natural Gas Production & Gathering	$ 1,197,000		$ 1,197,000	
3	Natural Gas Storage & Processing Plant	$ 382,000		$ 382,000	
4	Transmission Plant	$ 50,141,000		$ 50,141,000	Confidential
5	Distribution Plant (3)	$ 4,449,801,000	$ (10,296,636)	$ 4,439,504,364	I&E RB-4D
6	General Plant - 391 - UNITE - 6.70% (2)	$ 539,730,000	$ (75,385,331)	$ 464,344,669	OCA-III-8/28
7	Other Plant	$ -		$ -	
8	Total Gas Plant In Service	$ 5,042,025,000	$ (85,681,967)	$ 4,956,343,033	OCA-III-2 OCA-III-19 OCA-X-2

(1) Company Schedule C-2
(2) Includes $60.028 million for UNITE
(3) Adjustments for Distribution and General Plant are Confidential

ACCUMULATED DEPRECIATION

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Intangible Plant	$ -			
2	Natural Gas Production & Gathering	$ 1,153,000	$ -	$ 1,153,000	
3	Natural Gas Storage & Processing Plant	$ 33,000	$ -	$ 33,000	
4	Transmission Plant	$ 29,633,000	$ -	$ 29,633,000	
5	Distribution Plant - 2.06%	$ 1,131,575,000	$ (212,111)	$ 1,131,362,889	I&E RB-4D
6	General Plant - 5.71%	$ 156,166,000	$ (4,304,502)	$ 151,861,498	Confidential
7	Total Accumulated Depreciation	$ 1,318,560,000	$ (4,516,613)	$ 1,314,043,387	

(1) Company Schedule C-3

WORKING CAPITAL ALLOWANCE

		(1)					
			Company Proposed				OCA
		TY Expenses	Factor	Lead/Lag Days	Totals	Adjustments	Recommended
1	Revenue Lag Days				61.18		61.18
	Expense Lag Days						
2	Payroll	$ 82,929,000	12.00	$ 995,148,000			$ 935,100,000
3	Purchased Gas Costs	$ 397,163,000	39.85	$ 15,826,945,550		$ -	$ 15,826,945,550
4	All Other Expenses (3)	$ 192,619,000	27.08	$ 5,216,122,520			$ 5,055,143,900
5	Total	$ 672,711,000		$ 22,038,216,070			$ 21,817,189,450
6	O&M Expense Lag				32.76		32.76
7	Net Lead/Lag Days				28.413		28.41
8	Operating Expenses Per Day				$ 1,843,044		$ 1,813,048
9	Working Capital for O&M Expenses				$ 52,366,405		$ 51,514,127
10	Interest Payments				$ (4,667,000)		
11	Tax Payments				$ 4,402,000		
12	Prepaid Expenses				$ 10,047,000		$ 10,047,000
13	Total Working Capital Requirements (2)				$ 62,148,405	$ (587,278)	$ 61,561,127

(1) Company Schedule C-4
(2) differences due to rounding
(3) OCA-III-21

use company schedule and confirm balance

ACCUMULATED DEFERRED INCOME TAXES

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Gas Utility Plant	$ (633,775,000)	$ 1,304,944	$ (632,470,056)	Confidential
2	CIAC	$ 27,405,000	$ -	$ 27,405,000	
3	Federal ADIT	$ (606,370,000)	$ -	$ (605,065,056)	OCA Set III-30 OCA Set III-31
4	State Repairs Regulatory Liability	$ (34,960,000)	$ -	$ (34,960,000)	
	Sub-Total	$ (641,330,000)	$ -	$ (640,025,056)	
5	Pro-Rate Adjustment - EDIT (2)	$ 12,820,000	$ -	$ 12,820,000	OCA-III-30 Confidential
6	Balance At TY Period 9/30/2023	$ (628,510,000)	$ 1,304,944	$ (627,205,056)	

(1) Company Schedule C-6
(2) Components of the EDIT are Confidential not the balance

GAS PRODUCTION

		(1) Company Proposed	Adjustments	DCA Recommended	References
1	Beginning Balance	$ 14,000		$ 14,000	
	Environmental Expense Adj. #1				
2	2019 Expenditures	$ 4,811,000			OCA-Set VII-2
3	2020 Expenditures	$ 4,243,000			
4	2021 Expenditures	$ 6,460,000			
5	Three-Year Average	$ 5,171,333	$ (43,333)	$ 5,128,000	5 yr Avg. Confidential
6	Budgeted Expense	$ 4,188,000		$ 4,188,000	I&E RE-44
7	Proforma Adjustment	$ 983,333	$ (43,733)	$ 939,600	
8	Balance at Proforma Period	$ 997,333	$ (43,733)	$ 953,600	

(1) Company Schedule D-2, D-3, D-8

GAS SUPPLY PRODUCTION

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 358,286,000	$ -	$ 358,286,000	
2	Residential Gas Costs	$ 25,674,000	$ -	$ 25,674,000	
3	Commercial/Industrial Gas Costs	$ 13,203,000	$ -	$ 13,203,000	
4	Total Revenue for Cost of Gas	$ 38,877,000	$ -	$ 38,877,000	Sch. D-6
5	Balance at Proforma Period	$ 397,163,000	$ -	$ 397,163,000	

(1) Company Schedule D-2, D-3

	SALARIES AND WAGES Worksheet	(1) Budget Year	Table 7 Benchmark Adjustments	Sch. D-7 Merit Increases	SDR-RR-27 Incentive Compensation	Additional Employees	Total Proforma	Adjustments	OCA Recommended
1	Distribution Operations	$ 27,859,000	$ 1,148,000	$ 416,000	$ 51,000	$ 643,000	$ 30,117,000	$ (51,000)	$ 30,066,000
					$ 38,000	$ 505,000	$ 543,000	$ (38,000)	$ 505,000
2	Distribution Maintenance	$ 13,023,000		$ 195,000			$ 13,218,000	$ -	$ 13,218,000
3	Customer Accounts	$ 14,479,000		$ 216,000			$ 14,695,000	$ -	$ 14,695,000
4	Customer Service & Information	$ 1,042,000		$ 16,000			$ 1,058,000	$ -	$ 1,058,000
5	Sales	$ 899,000		$ 13,000			$ 912,000	$ -	$ 912,000
6	Administration & General - Operations (2)	$ 20,661,000		$ 309,000			$ 20,970,000	$ (2,312,000)	$ 16,055,000
7	Administration & General - Operations (2)							$ (2,603,000)	
8	Administration & General - Maintenance	$ 1,395,000		$ 21,000			$ 1,416,000	$ -	$ 1,416,000
9	Total Budgeted Salaries & Wages	$ 79,358,000	$ 1,148,000	$ 1,186,000	$ 89,000	$ 1,148,000	$ 82,929,000	$ (5,004,000)	$ 77,925,000
10	Total Benchmark Adjustments - check		$ 2,385,000						

Add'l Employees	64	OCA-Set III-7
Approved and identified	47	
Open Positions	(17)	
avg. salary	$ 45,845	I&E RE-5A
overall	$ (779,368)	To DM-4
	$ (5,694,368)	to DM-19

(1) Company Schedule D-7
Company Schedule D-3

(2) See I&E RE-17 - management incentive plan of $2,603,000 - Confidential
See I&E RE-17 UGI Incentive of $2,312,000

DISTRIBUTION EXPENSES

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 84,369,000		$ 82,254,667	
	Outside Contractor Expenses		$ (2,114,333)		OCA-III-33
	Salaries and Wages				
2	Distribution Operations	$ 416,000	$ -	$ 416,000	
3	Distribution Maintenance	$ 195,000	$ -	$ 195,000	Sch. D-7
4	Total Salaries and Wages	$ 611,000	$ -	$ 611,000	
	Adjustment 1				
5	Compensation Benchmark	$ 1,148,000	$ -	$ 1,148,000	Set III-11/13
6	Incremental Incentive Bonus	$ 51,000	$ (51,000)	$ -	
		$ 1,199,000		$ 1,148,000	
7	Employee Benefits - 10%	$ 119,900	$ (5,100)	$ 114,800	
8	Total Compensation Benefits	$ 1,318,900	$ (56,100)	$ 1,262,800	Sch D-9
	Adjustment 2				
9	Cybersecurity - 5 positions ($101K)	$ 505,000	$ -	$ 505,000	OCA Set III-12
10	Employee Benefits - $9,702x5 >10%	$ 48,510	$ -	$ 48,510	OCA Set III-17
11	Incentive Bonus 7.5% of $505,000	$ 37,875	$ (37,875)	$ -	
12	Total Cybersecurity	$ 591,385	$ (37,875)	$ 553,510	Sch. D-9
13	Unbudgeted Annual Capacity Lease Chrg.	$ 565,000	$ -	$ 565,000	Sch. D-15
	Succession Planning - Field Operations				
14	20 Additional Positions	$ 643,000	$ -	$ 643,000	
15	Employee Benefits cap at 10%	$ 124,000	$ (59,700)	$ 64,300	
16	Proforma Balance	$ 767,000	$ (59,700)	$ 707,300	Sch. D-17 Set III-17
17	Balance at Proforma Period	$ 88,222,285	$ (2,268,008)	$ 85,954,277	
	Increase over budgeted costs	$ 3,853,285			

(1) Company Schedule D-2, D-3

CUSTOMER ACCOUNTS EXPENSE

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 40,541,000	$ (9,000)	$ 40,532,000	OCA-III-33
2	Salaries and Wages	$ 216,000	$ -	$ 216,000	Sch. D-6
3	Emergency Relief Program (ERP)	$ 922,000	$ -	$ 922,000	OCA-III-24
4	Amortization period - Years	10		10	
5	Proforma Annual Recovery	$ 92,200	$ -	$ 92,200	Sch D-12
6	Unrecovered Interest on Cust. Deposits	$ 972,000	$ -	$ 972,000	Sch. D-15
					I&E RE-15
7	Universal Service Expenses	$ 548,000	$ -	$ 548,000	Sch. D-16
					I&E RE-50
8	Balance at Proforma Period	$ 42,369,200	$ (9,000)	$ 42,360,200	I&E RE-49
	Increase over budgeted costs	$ 1,828,200			

(1) Company Schedule D-2, D-3

UNCOLLECTIBLE ACCOUNTS EXPENSE

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 14,419,000		$ 14,419,000	Sch. D-11
2	Three-Year Average Tariff Revenues	$ 840,499,000			
3	Three-Year Average Uncollectibles	$ 13,841,000			
4	3-Yr Uncollectible Ratio	1.6470%		1.6470%	
5	2022 Present Rate Revenues - (2)	$ 1,058,040,000		$ 1,058,040,000	
6	Adjusted Uncollectibles	$ 17,426,000		$ 17,426,000	
7	Budgeted Uncollectibles	$ 15,400,000		$ 15,400,000	OCA-Set VII-1
8	Additional Uncollectibles	$ 2,026,000		$ 2,026,000	
9	Regulatory Asset Balance	$ 1,503,000	$ -	$ 1,503,000	OCA-III-24
10	10 Amortization Period	$ 150,300	$ -	$ 150,300	
11	Total Uncollectible Adjustment	$ 2,176,300	$ -	$ 2,176,300	OCA-VII-1
12	Balance at Proforma Period	$ 16,595,300	$ -	$ 16,595,300	
	Increase over budgeted costs	$ 2,176,300			
	Adjustment to Uncollectible Accounts			$ (618,042)	

(1) Company Schedule D-2, D-3

(2) Total Present Revenues less Misc. Revenues and Rent From Gas Properties

CUSTOMER INFORMATION & SERVICES

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 10,368,000	$ -	$ 10,368,000	OCA-III-6
2	Salaries and Wages	$ 16,000	$ -	$ 16,000	
3	Energy Efficiency & Conservation	$ 3,480,000		$ 3,480,000	I&E RE-51 OCA-VII-6
4	Balance at Proforma Period	$ 13,864,000		$ 13,864,000	
	Increase over budgeted costs	$ 3,496,000			

Check for Advertising, I&E RE-31
Section 53.53 III-A-25

(1) Company Schedule D-2, D-3 and D-7
Company Schedule D-19

SALES EXPENSE

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 1,725,000	$ (1,078,292)	$ 646,708	I&E-RE-31
2	Other Advertising Expense - Acct 913		$ (885,178)	$ -	III-A-25
3	Normalized Conservation Advertising		$ (193,114)	$ -	
4	Salary and Wages	$ 13,000	$ -	$ 13,000	Sch. D-7
5	Balance at Proforma Period	$ 1,738,000	$ (1,078,292)	$ 659,708	
6	Increase over Budgeted costs	$ 13,000			

Advertising Demonstrating and Selling I&E RE-30
Miscellaneous Sales
Section 53.53 Attachment III-25

(1) Company Schedule D-2, D-3
I&E RE-30

ADMINISTRATIVE & GENERAL EXPENSES

		(1) Company Proposed	Adjustments	OCA Recommended	References
					OCA-VII-7
1	Beginning Balance	$ 116,044,000	$ (13,855,933)	$ 102,188,067	OCA-VII-8
2	Company Membership Adjustment - Acct. 930		$ (540,912)		SDR-RR-30
3	Employee Activity - Acct . 926		$ (588,226)		I&E RE-24
4	Sponsorships - Acct. 930		$ (424,000)		I&E RE-22
5	Corporate Allocation-Incentive/Stock Awards - Acct. 923 (2)		$ (6,213,000)		I&E RE-17 OCA-X-1
6	ESC Costs - Acct. 923		$ (115,094)		OCA-X-1
7	Management Incentive Plan - $2,603,000 - Acct. 920 (2)		$ (2,603,000)		OCA- VII-13 - Set XI-1 (Conf)
8	UGI Incentive - Acct. 920 (2)		$ (2,312,000)		I&E RE-17
9	Outside Contractors Expenses		$ (22,667)		OCA-III-33
10	Employee Benefits - Acct. 926		$ (1,037,034)		I&E RE 28
11	A&G Operations Salaries	$ 309,000	$ -	$ 309,000	
12	A&G Maintenance Salaries	$ 21,000	$ -	$ 21,000	
13	Total Salaries and Wages	$ 330,000	$ -	$ 330,000	Sch. D-7
	Adjustment #3				
14	Environmental Adjustments (2020-2021)	$ 10,703,000	$ -	$ 10,703,000	
15	Balance Recovered in Prior Years	$ 8,376,000	$ -	$ 8,736,000	I&E RE-44
16	Unrecovered Expenditures (2)	$ 2,327,000	$ (1,861,600)	$ 465,400	Sch. D-8
	Rate Case Expenses - 1 yr. Amorization				
17	Total Expenses	$ 1,055,000	$ (527,500)	$ 527,500	OCA-III-16
18	Rate Cases Included in Budget	$ 1,000,000		$ 1,000,000	
19	Additional Expense	$ 55,000	$ (527,500)	$ (472,500)	Sch. D-10
	OSHA - ETS Compliance Costs				
20	Ongoing Costs for Tracking /Testing	$ 1,692,000	$ (1,692,000)	$ -	OCA-III-25
21	One-Time Cost - Comm/Legal	$ 191,000	$ (191,000)	$ -	OCA-III-25
22	Proforma Adjustment	$ 1,883,000	$ (1,883,000)	$ -	Sch. D-13
	Benefits Adjustment (Acct. 926)				OCA-III-22
23	Per Budget	$ (2,887,000)	$ 6,222,667	$ 3,335,667	OCA-VII-3
24	Cash Contributions	$ 11,364,000	$ 705,333	$ 12,069,333	
25	Estimated Cash Contributions	$ 9,168,000	$ 440,000	$ 9,608,000	
26	Capitalized Portion -40%	$ (3,667,200)	$ (176,000)	$ (3,843,200)	
		$ 5,500,800	$ 264,000	$ 5,764,800	
27	Proforma Adjustment	$ 8,387,800	$ (5,958,667)	$ 2,429,133	Sch. D-14
	Other Adjustments - I&D Acct. 925 (3)				
28	Three-Year average I&D	$ 1,353,333	$ -	$ 1,353,333	
29	Budgeted I&D	$ 2,023,000	$ -	$ 2,023,000	
30	Proforma Adjustment	$ (669,667)	$ -	$ 669,667	Sch. D-15
31	Balance at Proforma Period	$ 128,357,133	$ (22,747,366)	$ 105,609,767	
	Increase over Budgeted costs	$ 12,313,133			
					OCA-VII-7

Advertisement Section 53.53 III-A-25

(1) Company Schedule D-2, D3
(2) Red designated Confidential Information
(3) Includes Property Insurance

DEPRECIATION & AMORTIZATION EXPENSE

		Depreciation Rate Composite	(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance		$ 128,358,000	$ -	$ 128,358,000	
2	Intangible Plant	0.000%	$ -	$ -	$ -	
3	Natural Gas Production & Gathering	0.120%	$ 1,398	$ -	$ 1,398	
4	Natural Gas Storage & Processing	0.000%	$ -	$ -	$ -	
5	Transmission Plant	1.310%	$ 658,505	$ -	$ 658,505	
6	Distribution Plant	2.060%	$ 91,714,950	$ (212,111)	$ 91,502,839	I&E RB-4
7	General Plant	5.710%	$ 13,660,951	$ (4,304,502)	$ 9,356,449	I&E RB-4
						Confidential
	Other Plant:					
8	Common Plant - Allocated to Gas	3.630%	$ 1,311,428	$ -	$ 1,311,428	
9	Information Services Allocated to Gas	6.570%	$ 17,806,088	$ -	$ 17,806,088	OCA-III-8
		1.880%	$ 2,705,627	$ -	$ 2,705,627	
10	Empire Yard Building		$ (35,345)	$ -	$ (35,345)	
			$ 127,823,602	$ -	$ 123,306,989	OCA-III-26
11	Charged to Clearing Accounts		$ (8,371,000)	$ -	$ (8,371,000)	
12	Net Salvage Amortization		$ 6,083,750	$ -	$ 6,083,000	
	Company Proposed		$ 125,536,352	$ (4,517,363)	$ 121,018,989	OCA-III-27
13	Adjustment		$ (2,821,648)	$ (4,517,363)	$ (7,339,011)	

(1) Company Schedule D-21
Weidmayer Schedule II-3 to II-5

TAXES OTHER THAN INCOME TAXES

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 13,360,000	$ -	$ 13,360,000	
					Confidential
2	PURTA Taxes	$ 822,000	$ -	$ 822,000	OCA-III-18
3	Capital Stock	$ -			OCA-III-18
4	PA & Local Taxes	$ 1,868,000	$ (76,949)	$ 1,791,051	Confidential
	Payroll Taxes:				
5	Total Payroll	$ 79,358,000	$ (5,694,368)	$ 73,663,632	
6	FICA Rate	7.59%		7.5900%	
7	Budget Amount	$ 6,023,272	$ (432,203)	$ 5,591,070	I&E RE-3
8	Additional Payroll	$ 3,571,000	$ (89,000)	$ 3,482,000	
9	Additional FICA Taxes	$ 271,039	$ (6,755)	$ 264,284	
10	FUTA Expense - 0.14239%	$ 113,000	$ -	$ 113,000	
11	Additional FUTA Expense	$ 5,085	$ (127)	$ 4,958	
12	SUTA Expense - 0.6212%	$ 493,000	$ -	$ 493,000	
13	Additional SUTA Expense	$ 22,183	$ (553)	$ 21,630	
14	Total Additional Payroll Taxes	$ 298,307	$ (7,435)	$ 290,872	
15	PUC Assessment	$ 4,042,000	$ -	$ 4,042,000	OCA-III-18
16	Balance at Proforma Period	$ 13,658,307	$ (515,314)	$ 13,142,993	

(1) Company Schedule D-31, D-32

	FEDERAL & STATE INCOME TAXES	Present Rates			
		Company Proposed	Adjustments	OCA Recommended	References
1	Revenues	$ 1,145,466,000	$ (82,328,333)	$ 1,063,137,667	
2	Operating Expenses	$ (829,864,000)	$ 33,939,576	$ (795,924,424)	
3	Operating Income Before Taxes	$ 315,602,000	$ (48,388,757)	$ 267,213,243	
4	Interest Synchronization	$ (56,725,512)	$ (4,711,733)	$ (61,437,244)	
5	Base Taxable Income	$ 258,876,488	$ (53,100,490)	$ 205,775,998	
6	State Tax Depreciation over/under book	$ (133,816,000)	$ (4,495,000)	$ (138,311,000)	Co. Sch. D-34
7	State Taxable Income	$ 125,060,488	$ (57,595,490)	$ 67,464,998	
8	State Tax Rate - 9.99%	$ 12,493,543	$ (5,753,789)	$ 6,739,753	
9	Federal Tax Depreciation over/under book	$ (101,401,000)	$ (4,493,000)	$ (105,894,000)	
10	Federal Taxable Income	$ 144,981,946	$ (51,839,701)	$ 93,142,245	
11	Federal Tax Rate - 21.00%	$ 30,446,209	$ (10,886,337)	$ 19,559,871	
12	Total Tax before DIT	$ 42,939,751	$ (16,640,127)	$ 26,299,625	
	Deferred Federal Income Taxes				
13	Federal Tax over/under book	$ 98,131,000	$ 4,495,000	$ 102,626,000	
14	Federal Tax Rate - 18.03915% - blended	$ 17,702,000	$ 810,858	$ 18,512,858	OCA Set III-29
	Deferred State Income Taxes				
15	Repairs	$ 3,110,000	$ -	$ 3,110,000	
16	CIAC	$ (80,000)	$ -	$ (80,000)	
17	State Deferred Income Taxes	$ 3,030,000	$ -	$ 3,030,000	
18	Net Income Tax Expense	$ 63,671,751	$ (15,829,269)	$ 47,842,483	
19	ITC	$ (324,000)	$ -	$ (324,000)	
20	Combined Income Tax Expense	$ 63,347,751	$ (15,829,269)	$ 47,518,483	
	Federal Tax	$ 47,824,209		$ 37,748,730	
	State Tax	$ 15,523,543		$ 9,769,753	
	Check Total	$ 63,347,751	$ (15,829,269)	$ 47,518,483	

Company Schedule D-33

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Dante Mugrace, hereby state that the facts set forth in my Direct Testimony, OCA Statement 1, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 20, 2022
*327283

Signature: Dante Mugrace
Dante Mugrace

Consultant Address: PCMG and Associates
90 Moonlight Court
Toms River, NJ 08753

OCA Statement 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Gas Division	Docket No. R-2021-3030218

DIRECT TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 20, 2022

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APPENDICES

LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David J. Garrett. My business address is 101 Park Avenue, Suite 1125, Oklahoma Company, Oklahoma 73102.

Q. By whom are you employed and in what capacity?

A. I am the managing member of Resolve Utility Consulting, LLC. I am an independent consultant specializing in public utility regulation.

Q. Please summarize your educational background and professional experience.

A. I received a B.B.A. degree with a major in Finance, an M.B.A. degree, and a J.D. degree from the University of Oklahoma. I worked in private legal practice for several years before working as assistant general counsel at the Oklahoma Corporation Commission in 2011. At the Oklahoma Corporation Commission, I worked in the Office of General Counsel in regulatory proceedings. In 2012, I worked for the Public Utility Division as a regulatory analyst providing testimony in regulatory proceedings. After leaving the Oklahoma Corporation Commission, I formed Resolve Utility Consulting PLLC, where I have represented numerous consumer groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of capital and depreciation. I am a Certified Depreciation Professional with the Society of Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial

Analysts. A more complete description of my qualifications and regulatory experience is included in my curriculum vitae.[1]

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. Describe the purpose and scope of your testimony in this proceeding.

A. The primary purpose of my testimony is to provide my opinion on the estimated cost of capital and awarded rate of return recommendation for UGI Utilities, Inc. – Gas Division ("UGI" or the "Company"). I am responding to the direct testimony of Company witness Paul R. Moul.

Q. Please describe the organization of your testimony.

A. In the executive summary below, I provide an overview of cost of capital issues, my recommendations, and my response to the Company's testimony on these issues. In the sections that follow, I discuss the legal standards governing the awarded return issue, as well as the general concepts involved in estimating the cost of equity. I provide detailed analysis of the Discounted Cash Flow ("DCF") Model, the Capital Asset Pricing Model ("CAPM"), including my results for these models and my responses to Mr. Moul's results. I also address capital structure, which is a key component to the cost of capital.

I. EXECUTIVE SUMMARY

Q. Please summarize your recommendation to the Commission.

A. My testimony can be distilled to the following recommendations:

[1] Exhibit DJG-1.

- The Commission should reject the Company's proposed return on equity ("ROE") of 11.20% as excessive and unsupported. An objective cost of equity analysis shows that UGI's cost of equity is about 7.0%.

- The legal standards governing this issue do not mandate that the awarded ROE equate to the result of a particular financial model, but rather that it be reasonable under the circumstances. In my opinion, it is never appropriate to use an awarded ROE significantly above a regulated utility's cost of equity; however, that concept is even more important under these unique circumstances. Accordingly, I recommend the Commission award UGI an authorized ROE of 8.5%. Although 8.5% is still clearly above UGI's market-based cost of equity estimate, it represents a gradual yet meaningful move towards market-based cost of equity.

- I recommend the Commission reject UGI's proposed capital structure consisting of 44.88% debt and 55.12% equity. This equity-rich capital structure has the effect of increasing capital costs above a reasonable level. An objective mathematical analysis of UGI's optimal capital structure indicates a debt ratio as high as 55%. Likewise, the average debt ratio of the proxy group is 58%. Thus, UGI's proposed debt ratio is far too low to be considered reasonable. I recommend an imputed capital structure consisting of 50% debt and 50% equity. My adjustments to the Company's proposed ROE and capital structure equate to an overall weighted average rate of return of 6.24%.

My proposed adjustments are illustrated in the table below.[2]

Figure 1:
OCA Weighted Average Rate of Return Proposal

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long-Term Debt	50.0%	3.98%	1.99%
Common Equity	50.0%	8.50%	4.25%
Total	100.0%		6.24%

The details supporting my proposed adjustments are discussed further in my testimony.

[2] *See also* Exhibit DJG-16.

Q. Are you recommending any adjustments to UGI's proposed cost of debt?

A. No.

A. Overview and Background

Q. Please explain the concept and significance of the Cost of Capital.

A. The term cost of capital, or Weighted Average Cost of Capital (WACC),[3] refers to the weighted average cost of the components within a company's capital structure, including the costs of both debt and equity. The three primary components of a company's WACC include the following:

1. Cost of Debt
2. Cost of Equity
3. Capital Structure

Determining the cost of debt is relatively straight-forward. Interest payments on bonds are contractual, embedded costs that are generally calculated by dividing total interest payments by the book value of outstanding debt. Determining the cost of equity, on the other hand, is more complex. Unlike the known, contractual, and embedded cost of debt, there is not any explicitly quantifiable "cost" of equity. Instead, the cost of equity must be estimated through various financial models. Cost of capital is expressed as a weighted average because it is based upon a company's relative levels of debt and equity, as defined by the particular capital structure of that company. The basic WACC equation used in regulatory proceedings is presented as follows:

[3] The terms cost of capital and WACC are synonymous and used interchangeably throughout this testimony.

Equation 1:
Weighted Average Cost of Capital

$$WACC = \left(\frac{D}{D+E}\right) C_D + \left(\frac{E}{D+E}\right) C_E$$

where:	$WACC$	=	*weighted average cost of capital*
	D	=	*book value of debt*
	C_D	=	*embedded cost of debt capital*
	E	=	*book value of equity*
	C_E	=	*market-based cost of equity capital*

Companies in the competitive market often use their WACC as the discount rate to determine the value of capital projects, so it is important that this figure be estimated accurately.

Q. How do experts and regulators typically assess the ROEs awarded to utilities and the corresponding opportunity for shareholders?

A. Investors, company managers, and academics around the world have used models, such as the CAPM and DCF to closely estimate cost of equity for many years, and weigh the results achieved against the results from proxy groups. Each of these concepts will be discussed in more detail later in my testimony.

B. <u>Recommendation</u>

Q. Please summarize your ROE recommendation to the Pennsylvania Public Utility Commission (Commission).

A. Pursuant to the legal and technical standards guiding this issue, the awarded ROE should be based on, or reflective of, the utility's cost of equity. UGI's estimated cost of equity is about 7.0%, when using reasonable inputs. However, legal standards do not mandate the awarded ROE be set exactly equal to the cost of equity. Rather, in *Federal Power Commission v. Hope Natural Gas Co.*, the U.S. Supreme Court found that, although the awarded return should be based on a utility's cost of equity, the "end result" should be just and reasonable.[4] Therefore, I recommend the Commission award UGI an ROE of 8.5%. In my opinion, an awarded ROE that is set too far above a regulated utility's cost of equity (which in this case is only about 7.0%) runs the risk of being at odds with the standards set forth in *Hope*[5] and *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*.[6] In other words, setting the awarded ROE far above the cost of equity results in an excess transfer of wealth from customers to the utility, which is never appropriate.

Q. If 8.5% exceeds UGI's actual cost of equity and still, in your opinion, results in an excessive wealth transfer from shareholders to ratepayers, how can it still be considered a just and reasonable result?

A. The ratemaking concept of "gradualism," though usually applied from ratepayers' standpoint to minimize rate shock, could also be applied illustratively to shareholders. An awarded return as low as 7.0% in any current rate proceeding would represent a stark and substantial movement. While generally reducing awarded ROEs for utilities would move awarded returns closer to market-based costs and so reduce the excess transfer of wealth from ratepayers to shareholders, I believe it is advisable to do so gradually. One of the primary reasons UGI's actual cost of equity is so low is because UGI is a low-risk investment. In general, utility stocks are low-risk investments because movements in their stock prices are not volatile. If the Commission were to make a significant, sudden change

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[4] *See Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944). Here, the Court states that it is not mandating the various permissible ways in which the rate of return may be determined, but instead indicates that the end result should be just and reasonable. This is sometimes called the "end result" doctrine.

[5] *Id.*

[6] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692–93 (1923).

in the awarded ROE anticipated by regulatory stakeholders, it could have the undesirable effect of notably increasing the Company's risk profile, which could be in contravention to the *Hope* Court's "end result" doctrine. An awarded ROE of 8.5% represents a good balance between the Supreme Court's indications that awarded ROEs should be based on cost, while also recognizing that the end result must be just and reasonable under the circumstances. An awarded ROE of 8.5% represents a relatively gradual, yet decisive move toward UGI's market-based cost of equity, while still providing UGI's shareholders with the opportunity to earn a return that is more than 100 basis points above UGI's market-based cost of equity (8.5% vs. 7.0%).

Q. Please summarize your recommendation regarding capital structure.

A. The Company proposes an equity-rich capital structure consisting of 55.12% common equity and only 44.88% debt.[7] Unlike competitive companies, which have a natural financial incentive to issue sufficient amounts of debt to maximize profits, regulated utilities do not have the same incentive to issue sufficient amounts of debt. However, even Mr. Moul's own utility proxy group reported a debt ratio of 58%, which is substantially higher than the debt ratio proposed by UGI.[8] Although there is strong evidence to support an imputed debt ratio as high as 58%, I recommend the Commission impute a ratemaking debt ratio of 50% (and 50% equity) in the interest of a more gradual approach.

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[7] Direct Testimony of Paul R. Moul, p. 21, lines 24-25.

[8] Exhibit DJG-15.

C. Response to the Company's Testimony

Q. Please provide an overview of the problems you have identified with the Company's testimony regarding cost of equity, capital structure, and the resulting awarded ROE.

A. Mr. Moul proposes a return on equity of 11.20%.[9] Mr. Moul's recommendation is based on the CAPM, DCF Model, and other models. A summary of Mr. Moul's positions are shown in the figure below.[10]

Figure 2:
UGI Weighted Average Rate of Return Proposal

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long-Term Debt	44.9%	3.98%	1.79%
Common Equity	55.1%	11.20%	6.17%
Total	100.0%		7.96%

However, several of his key assumptions and inputs to these models violate fundamental, widely accepted tenets in finance and valuation. I find several aspects of Mr. Moul's approach and resulting recommendations to be problematic, including the growth rates used in his DCF models and his inflated estimate for the equity risk premium ("ERP") used in his CAPM analysis. In addition, Mr. Moul adds what he calls a "leverage adjustment" to the results of his models, which inappropriate inflate the results. The Commission has previously rejected Mr. Moul's proposed leverage adjustment.[11] Finally, Mr. Moul

[9] Direct Testimony of Paul R. Moul, p. 4, lines 12-15.

[10] *See also* Direct Testimony of Paul R. Moul, Exhibit PRM-1, Sch. 1, p. 1.

[11] Pa. P.U.C. v. PPL Elec. Util. Corp., Docket No. R-2012-2290597, Order, 52 (Dec. 28, 2012), p. 52 of 105.

inappropriately adds premium to his cost of equity estimate for management performance, which further inflates a figure that is already overestimated.

Regarding capital structure, Mr. Moul adopts the Company's FPFTY capital structure ratios of 44.88% long-term debt and 55.12% common equity.[12] As discussed in my testimony, the Company does not have a financial incentive to operate with sufficient amounts of debt in its capital structure, and the evidence shows that UGI's proposed debt ratio is too low.

II. LEGAL STANDARDS AND THE AWARDED RETURN

Q. Discuss the legal standards governing the awarded rate of return on capital investments for regulated utilities.

A. In *Wilcox v. Consolidated Gas Co. of New York*, the U.S. Supreme Court first addressed the meaning of a fair rate of return for public utilities.[13] The Court found that "the amount of risk in the business is a most important factor" in determining the appropriate allowed rate of return.[14] As referenced earlier, in two subsequent landmark cases, the Court set forth the standards by which public utilities are allowed to earn a return on capital investments. First, in *Bluefield*, the Court held:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public. . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and

[12] Direct Testimony of Paul R. Moul, p. 4, lines 12-15.

[13] *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19 (1909).

[14] *Id.* at 48.

> economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[15]

Then, in *Hope*, the Court expanded on the guidelines set forth in *Bluefield* and stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses <u>but also for the capital costs of the business.</u> These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[16]

The cost of capital models I have employed in this case are designed to be in accordance with the foregoing legal standards.

Q. Is it important that the awarded rate of return be based on the Company's actual cost of capital?

A. Yes. The U.S. Supreme Court in *Hope* makes it clear that the allowed return should be based on the actual cost of capital.[17] Moreover, the awarded return must also be fair, just, and reasonable under the circumstances of each case. Among the circumstances that must be considered in each case are the broad economic and financial impacts to the cost of equity and awarded return caused by market forces and other factors. As a starting point, however, scholars agree that the actual cost of capital must be considered:

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[15] *Bluefield* at 692–93.

[16] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (emphasis added) (internal citations omitted).

[17] The term "cost of capital" includes both debt and equity. The overall awarded rate of return should be based on the utility's cost of capital, which the awarded ROE should be based on the utility's cost of equity.

> Since by definition the cost of capital of a regulated firm represents precisely the expected return that investors could anticipate from other investments while bearing no more or less risk, and since investors will not provide capital unless the investment is expected to yield its opportunity cost of capital, the correspondence of the definition of the cost of capital with the court's definition of legally required earnings appears clear.[18]

The models I have employed in this case closely estimate the Company's true cost of equity. If the Commission sets the awarded return based on my lower and more reasonable rate of return, it will better comply with the U.S. Supreme Court's standards, allow the Company to maintain its financial integrity, and achieve reasonable returns for its investors. On the other hand, if the Commission sets the allowed rate of return much higher than the true cost of capital, as requested by UGI, it will result in an inappropriate transfer of wealth from ratepayers to shareholders.[19]

Q. What does this legal standard mean for determining the awarded return and the cost of capital?

A. The awarded return and the cost of capital are different but related concepts. On the one hand, the legal and technical standards encompassing this issue require that the awarded return reflect the true cost of capital. Yet on the other hand, the two concepts differ in that the legal standards do not mandate that awarded returns exactly match the cost of capital. Instead, awarded returns are set through the regulatory process and may be influenced by various factors other than objective market drivers. By contrast, the cost of capital should be evaluated objectively and be closely tied to economic realities, such as stock prices,

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[18] A Lawrence Kolbe, James A. Read, Jr. & George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities* 21 (The MIT Press 1984).

[19] Roger A. Morin, *New Regulatory Finance* 23–24 (Public Utilities Reports, Inc. 2006) (1994) ("[I]f the allowed rate of return is greater than the cost of capital, capital investments are undertaken and investors' opportunity costs are more than achieved. Any excess earnings over and above those required to service debt capital accrue to the equity holders, and the stock price increases. In this case, the wealth transfer occurs from ratepayers to shareholders.").

dividends, growth rates, and, most importantly, risk. The cost of capital can be estimated by financial models used by firms, investors, and academics around the world for decades. The problem is, with respect to regulated utilities, there has been a trend in which awarded returns fail to closely track with market-based cost of capital, as further discussed below. To the extent this occurs, the results are detrimental to ratepayers and the state's economy.

Q. Describe the economic impact that occurs when the awarded return strays too far from the U.S. Supreme Court's time-honored cost of equity standards.

A. When the awarded ROE is set far above the cost of equity, it runs the risk of violating the U.S. Supreme Court's standards. This has the effect of diverting dollars from ratepayers for their internal or business uses that would otherwise support the local or state economy to the utility's shareholders at large. Moreover, establishing an awarded return that far exceeds true cost of capital effectively prevents the awarded returns from changing along with economic conditions. This is especially true given the fact that regulators tend to be influenced by the awarded returns in other jurisdictions, regardless of the various unknown factors influencing those awarded returns. If regulators rely too heavily on the awarded returns from other jurisdictions, they can create a cycle over time that bears little relation to the market-based cost of equity. In fact, this is exactly what we have observed since 1990. This is yet another reason why it is crucial for regulators to put more emphasis on the target utility's actual cost of equity than on the awarded returns from other jurisdictions. Awarded returns may be influenced by settlements and other political factors not based on true market conditions. In contrast, the true cost of equity as estimated through objective models is not influenced by these factors but is instead driven by market-based factors.

Q. Can you illustrate and provide a comparison of the relationship between awarded utility returns and market cost of equity since 1990?

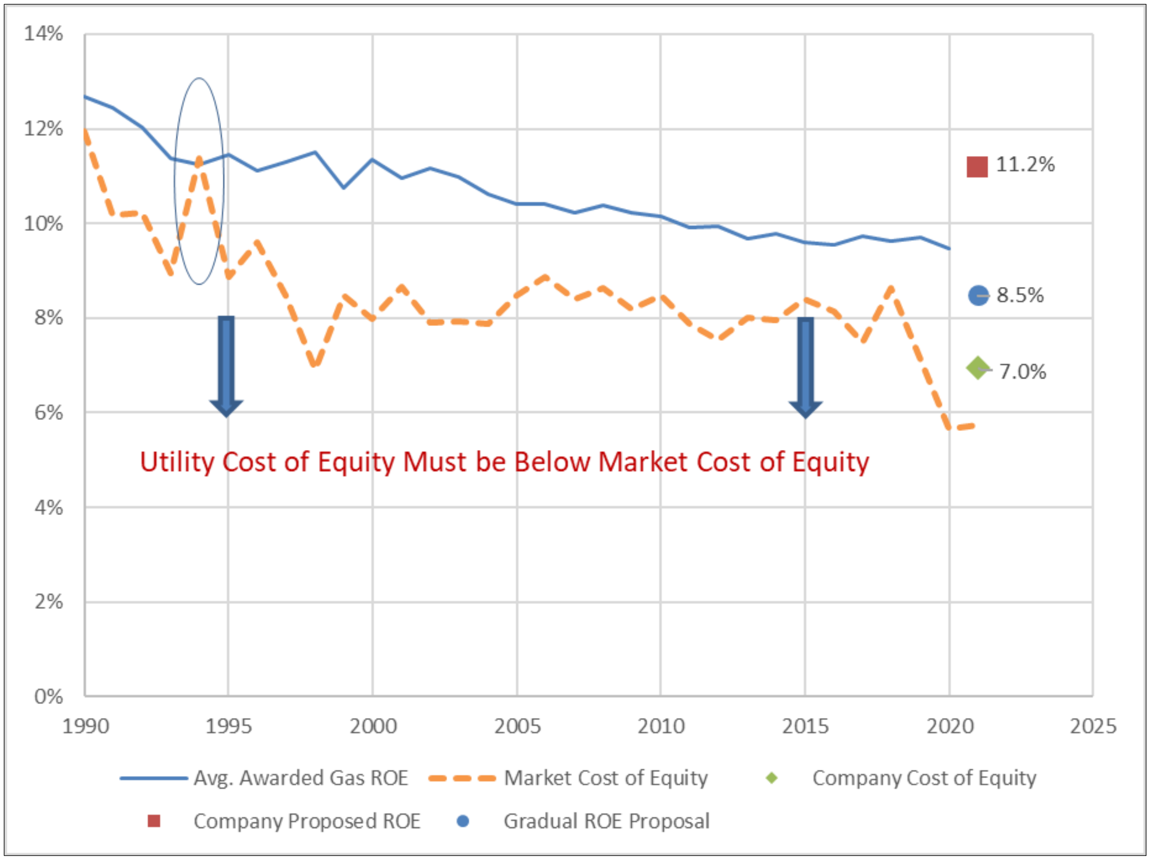
A. Yes. As shown in the figure below, awarded returns for electric and gas utilities have been above the average required market return since 1990.[20] Because utility stocks are consistently far less risky than the average stock in the marketplace, the cost of equity for utility companies is less than the market cost of equity.

To illustrate this fact, the graph in the figure below shows three trend lines. The top two line are the average annual awarded returns since 1990 for U.S. regulated electric and gas utilities. The bottom line is the required market return over the same period. As discussed in more detail later in my testimony, the required market return is essentially the return that investors would require if they invested in the entire market and, as such, the required market return is essentially the cost of equity of the entire market. Since it is undisputed that utility stocks are less risky than the average stock in the market, then the utilities' cost of equity must be less than the market cost of equity.[21] Thus, awarded returns (the solid line) should generally be below the market cost of equity (the dotted line), since awarded returns are supposed to be based on true cost of equity.

[20] Exhibit DJG-13.

[21] This fact can be objectively measured through a term called "beta," as discussed later in the testimony. Utility betas are less than one, which means utility stocks are less risky than the "average" stock in the market.

Figure 3:
Awarded ROEs vs. Market Cost of Equity



Notwithstanding the data in this graph, awarded ROEs have been consistently above the market cost of equity for many years. Also as shown in this graph, since 1990, there was only one year in which the average awarded ROE was below the market cost of equity. In 1994, regulators awarded ROEs that were the closest to utilities' market-based cost of equity. In my opinion, when awarded ROEs for utilities are below the market cost of equity, regulators more closely conform to the standards set forth by *Hope* and *Bluefield* and minimize the excess wealth transfer from ratepayers to shareholders.

Q. Have other analysts commented on this national phenomenon of awarded ROEs exceeding market-based cost equity for utilities?

A. Yes. In his article published in Public Utilities Fortnightly in 2016, Steve Huntoon observed that even though utility stocks are less risky than the stocks of competitive industries, utility stocks have nonetheless outperformed the broader market.[22] Specifically, Mr. Huntoon notes the following three points which lead to a problematic conclusion:

> 1. Jack Bogle, the founder of Vanguard Group and a Wall Street legend, provides rigorous analysis that the long-term total return for the broader market will be around 7 percent going forward. Another Wall Street legend, Professor Burton Malkiel, corroborates that 7 percent in the latest edition of his seminal work, A Random Walk Down Wall Street.
>
> 2. Institutions like pension funds are validating the first point by piling on risky investments to try and get to a 7.5 percent total return, as reported by the Wall Street Journal.
>
> 3. Utilities are being granted returns on equity around 10 percent.[23]

Other scholars have also observed that awarded ROEs have not appropriately tracked with declining interest rates over the years, and that excessive awarded ROEs have negative economic impacts. In a white paper issued in 2017, Charles S. Griffey stated:

[22] Steve Huntoon, "Nice Work If you can Get It," Public Utilities Fortnightly (Aug. 2016).

[23] *Id*.

> The "risk premium" being granted to utility shareholders is now higher than it has ever been over the last 35 years. Excessive utility ROEs are detrimental to utility customers and the economy as a whole. From a societal standpoint, granting ROEs that are higher than necessary to attract investment creates an inefficient allocation of capital, diverting available funds away from more efficient investments. From the utility customer perspective, if a utility's awarded and/or achieved ROE is higher than necessary to attract capital, customers pay higher rates without receiving any corresponding benefit.[24]

It is interesting that both Mr. Huntoon and Mr. Griffey use the word "sticky" in their articles to describe the fact that awarded ROEs have declined at a much slower rate than interest rates and other economic factors resulting in a decline in capital costs and expected returns on the market. It is not hard to see why this phenomenon of "sticky" ROEs has occurred. Because awarded ROEs are often based primarily on a comparison with other awarded ROEs around the country, the average awarded returns effectively fail to adapt to true market conditions, and regulators seem reluctant to deviate from the average. Once utilities and regulatory commissions become accustomed to awarding rates of return higher than market conditions actually require, this trend becomes difficult to reverse. The fact is, utility stocks are less risky than the average stock in the market, and thus, awarded ROEs should be less than the expected return on the market. However, that is rarely the case. My proposal assists the Commission in "see[ing] the gap between allowed returns and cost of capital,"[25] and reconciling this issue in an equitable manner.

[24] Charles S. Griffey, "When 'What Goes Up' Does Not Come Down: Recent Trends in Utility Returns," White Paper (February 2017).

[25] Leonard Hyman & William Tilles, "Don't Cry for Utility Shareholders, America," Public Utilities Fortnightly (October 2016).

Q. Summarize the legal standards governing the awarded ROE issue.

A. The Commission should strive to move the awarded return to a level more closely aligned with the Company's actual, market-derived cost of capital while keeping in mind the following two legal principles outlined below.

1. Risk is the most important factor when determining the awarded return. The awarded return should be commensurate with those returns on investments of corresponding risk.

The legal standards articulated in *Hope* and *Bluefield* demonstrate that the U.S. Supreme Court understands one of the most basic, fundamental concepts in financial theory: the more (or less) risk an investor assumes, the more (or less) return the investor requires. Since utility stocks are low risk, the return required by equity investors should be relatively low. I have used financial models to closely estimate the Company's cost of equity, and these financial models account for risk. The cost of equity models confirm the industry experiences relatively low levels of risk by producing relatively low cost of equity results. In turn, the awarded ROE in this case should reflect UGI's relatively low market risk.

2. The awarded return should be sufficient to assure financial soundness and integrity under efficient management.

Because awarded returns in the regulatory environment have not closely tracked market-based trends and commensurate risk, utility companies have been able to remain more than financially sound, perhaps despite management inefficiencies. In fact, the transfer of wealth from ratepayers to shareholders has been so far removed from actual cost-based drivers that a utility could remain financially sound even under relatively inefficient management. Therefore, regulatory commissions should strive to set utilities' returns based on actual market conditions to promote prudent and efficient management and minimize economic waste.

III. GENERAL CONCEPTS AND METHODOLOGY

Q. Discuss your approach to estimating the cost of equity in this case.

A. While a competitive firm must estimate its own cost of capital to assess the profitability of competing capital projects, regulators determine a utility's cost of capital to establish a fair rate of return. The legal standards set forth above do not include specific guidelines regarding the models that must be used to estimate the cost of equity for utilities. Over the years, however, regulatory commissions have consistently relied on several models. The models I have employed in this case have been the two most widely used and accepted in regulatory proceedings for many years. The specific inputs and calculations for these models are described in more detail below.

Q. Please explain why you used multiple models to estimate the cost of equity.

A. These models attempt to measure the return on equity required by investors by estimating several different inputs. It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of conducting the model. By using multiple models, the analyst can compare the results of the models and look for outlying results and inconsistencies. Likewise, if multiple models produce a similar result, it may indicate a narrower range for the cost of equity estimate.

Q. Please discuss the benefits of choosing a proxy group of companies in conducting cost of capital analyses.

A. The cost of equity models in this case can be used to estimate the cost of capital of any individual, publicly traded company. There are advantages, however, to conducting cost of capital analysis on a proxy group of companies that are comparable to the target company. First, it is better to assess the financial soundness of a utility by comparing it to a group of other financially sound utilities. Second, using a proxy group provides more reliability and confidence in the overall results because there is a larger sample size. Finally, the use of a proxy group is often a pure necessity when the target company is a subsidiary that is not publicly traded, as is the case here. This is because the financial models used to estimate the cost of equity require information from publicly traded firms, such as stock prices and dividends.

Q. Describe the proxy group you selected in this case.

A. In this case, I chose to use the same proxy group used by Mr. Moul. There could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy group.[26] By using the same proxy group, we can remove a relatively insignificant variable from the equation and focus on the primary factors driving UGI's cost of equity estimate.

IV. RISK AND RETURN CONCEPTS

Q. Discuss the general relationship between risk and return.

A. Risk is among the most important factors for the Commission to consider when determining the allowed return. Thus, it is necessary to understand the relationship between risk and return. There is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand.

[26] Exhibit DJG-2.

There are two primary types of risk: firm-specific risk and market risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees.

Q. Discuss the differences between firm-specific risk and market risk.

A. Firm-specific risk affects individual companies, rather than the entire market. For example, a competitive firm might overestimate customer demand for a new product, resulting in reduced sales revenue. This is an example of a firm-specific risk called "project risk."[27] There are several other types of firm-specific risks, including: (1) "financial risk" – the risk that equity investors of leveraged firms face as residual claimants on earnings; (2) "default risk" – the risk that a firm will default on its debt securities; and (3) "business risk" – which encompasses all other operating and managerial factors that may result in investors realizing less than their expected return in that particular company. While firm-specific risk affects individual companies, market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate risk, inflation risk, and the risk of major socio-economic events. When there are changes in these risk factors, they affect all firms in the market to some extent.[28]

Analysis of the U.S. market in 2001 provides a good example for contrasting firm-specific risk and market risk. During that year, Enron Corp.'s stock fell from $80 per share to its low when the company filed bankruptcy at the end of the year. If an investor's portfolio had held only Enron stock at the beginning of 2001, this irrational investor would

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[27] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 62–63 (3rd ed., John Wiley & Sons, Inc. 2012).

[28] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 149 (9th ed., McGraw-Hill/Irwin 2013).

have lost the entire investment by the end of the year due to assuming the full exposure of Enron's firm-specific risk (in that case, imprudent management). On the other hand, a rational, diversified investor who invested the same amount of capital in a portfolio holding every stock in the S&P 500 would have had a much different result that year. The rational investor would have been relatively unaffected by the fall of Enron because his or her portfolio included about 499 other stocks. Each of those stocks, however, would have been affected by various market risk factors that occurred that year. Thus, the rational investor would have incurred a relatively minor loss due to market risk factors, while the irrational investor would have lost everything due to firm-specific risk factors.

Q. Can equity investors reasonably minimize firm-specific risk?

A. Yes. A fundamental concept in finance is that firm-specific risk can be eliminated through diversification.[29] If someone irrationally invested all his or her funds in one firm, he or she would be exposed to all the firm-specific risk and the market risk inherent in that single firm. Rational investors, however, are risk-averse and seek to eliminate risk they can control. Investors can eliminate firm-specific risk by adding more stocks to their portfolio through a process called "diversification." There are two reasons why diversification eliminates firm-specific risk.

First, each stock in a diversified portfolio represents a much smaller percentage of the overall portfolio than it would in a portfolio of just one or a few stocks. Thus, any firm-

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[29] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 179–80 (3rd ed., South Western Cengage Learning 2010).

specific action that changes the stock price of one stock in the diversified portfolio will have only a small impact on the entire portfolio.[30]

The second reason why diversification eliminates firm-specific risk is that the effects of firm-specific actions on stock prices can be either positive or negative for each stock. Thus, in large diversified portfolios, the net effect of these positive and negative firm-specific risk factors will be essentially zero and will not affect the value of the overall portfolio.[31] Firm-specific risk is also called "diversifiable risk" because it can be easily eliminated through diversification.

Q. Is it well-known and accepted that, because firm-specific risk can be easily eliminated through diversification, the market does not reward such risk through higher returns?

A. Yes. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company. Thus, the risks associated with an individual firm's operations are not rewarded by the market. In fact, firm-specific risk is also called "unrewarded" risk for this reason. Market risk, on the other hand, cannot be eliminated through diversification. Because market risk cannot be eliminated through diversification, investors expect a return for assuming this type of risk. Market risk is also called "systematic risk." Scholars recognize the fact that market risk, or systematic risk, is the only type of risk for which investors expect a return for bearing:

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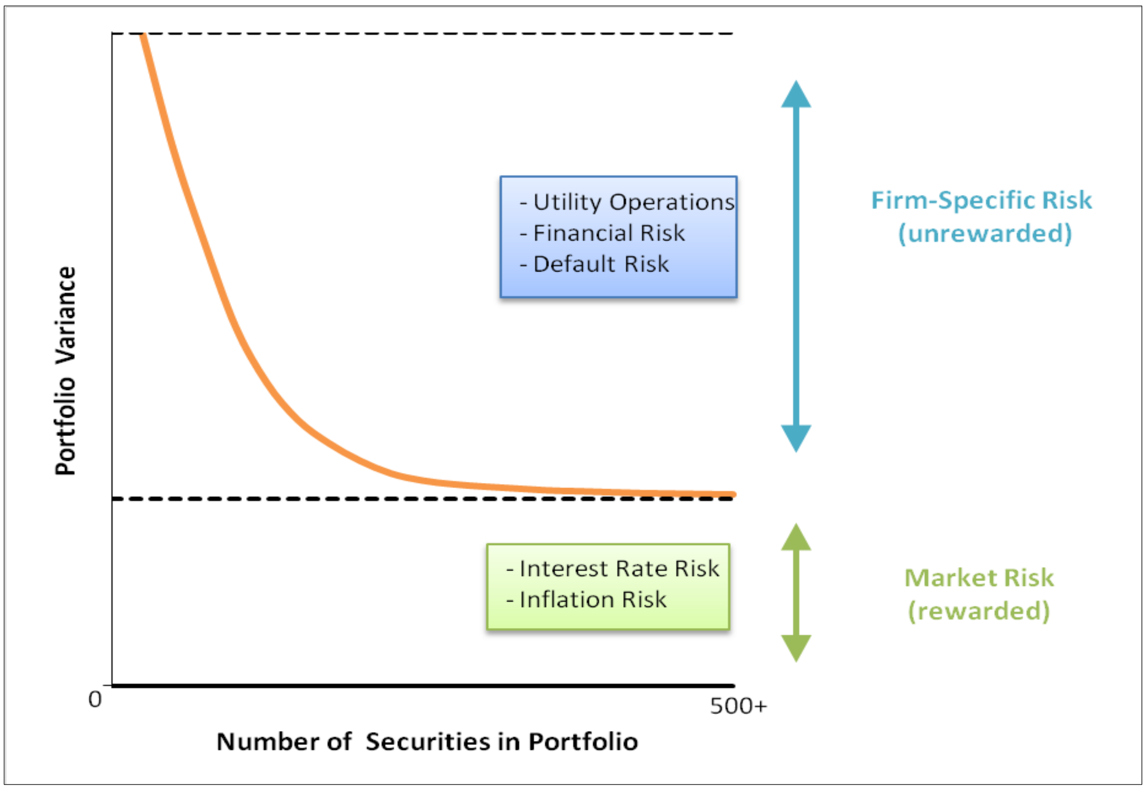
[30] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 64 (3rd ed., John Wiley & Sons, Inc. 2012).

[31] *Id.*

> If investors can cheaply eliminate some risks through diversification, then we should not expect a security to earn higher returns for risks that can be eliminated through diversification. Investors can expect compensation only for bearing systematic risk (i.e., risk that cannot be diversified away).[32]

These important concepts are illustrated in the figure below. Some form of this figure is found in many financial textbooks.

Figure 4:
Effects of Portfolio Diversification



This figure shows that as stocks are added to a portfolio, the amount of firm-specific risk is reduced until it is essentially eliminated. No matter how many stocks are added, however, there remains a certain level of fixed market risk. The level of market risk will

[32] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010) (emphasis added).

vary from firm to firm. Market risk is the only type of risk that is rewarded by the market and is thus the primary type of risk the Commission should consider when determining the allowed return.

Q. Describe how market risk is measured.

A. Investors who want to eliminate firm-specific risk must hold a fully diversified portfolio. To determine the amount of risk that a single stock adds to the overall market portfolio, investors measure the covariance between a single stock and the market portfolio. The result of this calculation is called "beta."[33] Beta represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than 1.0 are relatively more sensitive to market risk than the average stock. For example, if the market increases (or decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (or decrease) by 1.5%. In contrast, stocks with betas of less than 1.0 are less sensitive to market risk, such that if the market increases (or decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (or decrease) by 0.5%. Thus, stocks with low betas are relatively insulated from market conditions. The beta term is used in the CAPM to estimate the cost of equity, which is discussed in more detail later.[34]

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[33] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180–81 (3rd ed., South Western Cengage Learning 2010).

[34] Though it will be discussed in more detail later, Exhibit DJG-8 shows that the average beta of the proxy group was less than 1.0. This confirms the well-known concept that utilities are relatively low-risk firms.

Q. Are public utilities characterized as defensive firms that have low betas, have low market risk, and are relatively insulated from overall market conditions?

A. Yes. Although market risk affects all firms in the market, it affects different firms to varying degrees. Firms with high betas are affected more than firms with low betas, which is why firms with high betas are riskier. Stocks with betas greater than one are generally known as "cyclical stocks." Firms in cyclical industries are sensitive to recurring patterns of recession and recovery known as the "business cycle."[35] Thus, cyclical firms are exposed to a greater level of market risk. Securities with betas less than one, on the other hand, are known as "defensive stocks." Companies in defensive industries, such as public utility companies, "will have low betas and performance that is comparatively unaffected by overall market conditions."[36] In fact, financial textbooks often use utility companies as prime examples of low-risk, defensive firms.[37] The figure below compares the betas of several industries and illustrates that the utility industry is one of the least risky industries in the U.S. market.[38]

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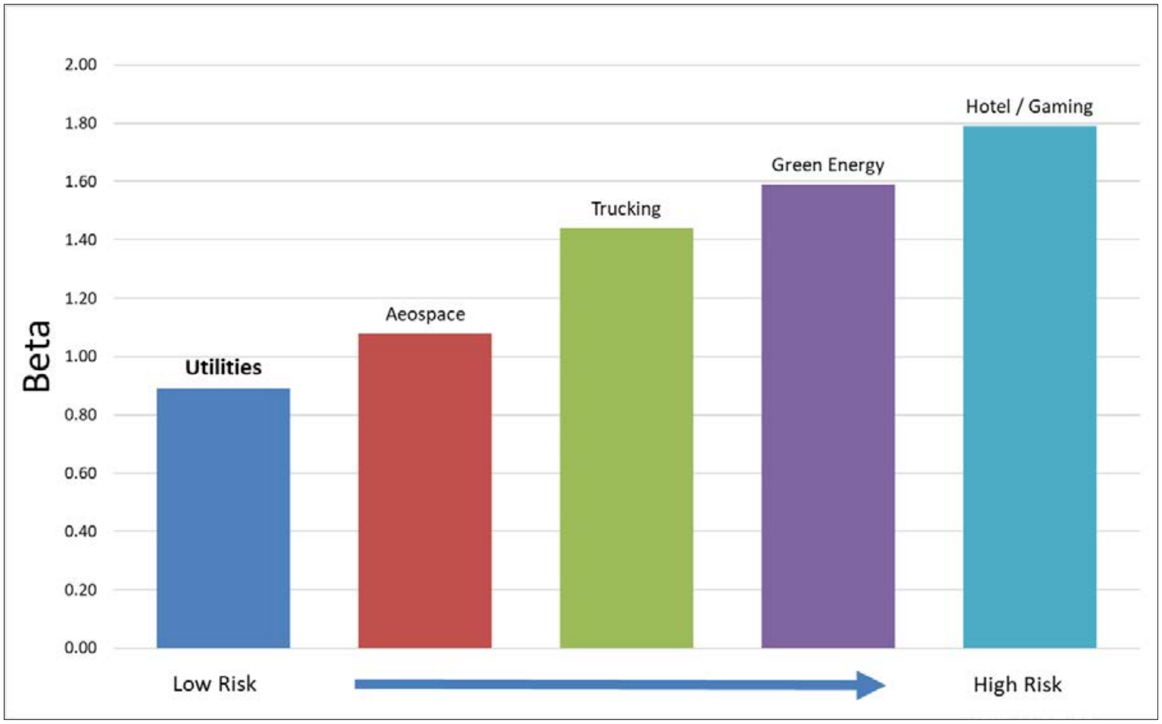
[35] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 382 (9th ed., McGraw-Hill/Irwin 2013).

[36] Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 383 (9th ed., McGraw-Hill/Irwin 2013).

[37] *See e.g.*, Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 382 (9th ed., McGraw-Hill/Irwin 2013); *see also* Aswath Damodaran, Investment Valuation: Tools and Techniques for Determining the Value of Any Asset 196 (3rd ed., John Wiley & Sons, Inc. 2012).

[38] *See* Betas by Sector (US) at http://pages.stern.nyu.edu/~adamodar/. The exact beta calculations are not as important as illustrating the well-known fact that utilities are low-risk companies. The fact that the utility industry is one of the lowest risk industries in the country should not change from year to year.

Figure 5:
Beta by Industry



The fact that utilities are defensive firms that are exposed to little market risk is beneficial to society. When the business cycle enters a recession, consumers can be assured that their utility companies will be able to maintain normal business operations and provide safe and reliable service under prudent management. Likewise, utility investors can be confident that utility stock prices will not fluctuate widely. So, while it is preferable for utilities to be defensive firms that experience little market risk and relatively insulated from market conditions, this should also be appropriately reflected in UGI's awarded return.

V. DCF ANALYSIS

Q. Describe the DCF Model.

A. The DCF Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. These versions, along with other formulas and theories related to the DCF Model are discussed in more detail in Appendix A. For this case, I chose to use the Quarterly Approximation DCF Model because it accounts for the quarterly growth of dividends (as opposed to annual growth). I also used this variation of the DCF Model in the interest of reasonableness, as it produces the highest cost of equity estimates compared with the other DCF Model variations.

Q. Describe the inputs to the DCF Model.

A. There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate. The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated. The formula is presented as follows:

Equation 2:
Quarterly Approximation Discounted Cash Flow Model

$$K = \left[\frac{d_0(1+g)^{1/4}}{P_0} + (1+g)^{1/4}\right]^4 - 1$$

where: K = *discount rate / required return*
d_0 = *current quarterly dividend per share*
P_0 = *stock price*
g = *expected growth rate of future dividends*

I discuss each of these inputs separately below.

A. **Stock Price**

Q. How did you determine the stock price input of the DCF Model?

A. For the stock price (P_0), I used a 30-day average of stock prices for each company in the proxy group.[39] Analysts sometimes rely on average stock prices for longer periods (e.g., 60, 90, or 180 days). According to the efficient market hypothesis, however, markets reflect all relevant information available at a particular time, and prices adjust instantaneously to the arrival of new information.[40] Past stock prices, in essence, reflect outdated information. The DCF Model used in utility rate cases is a derivation of the dividend discount model, which is used to determine the current value of an asset. Thus, according to the dividend discount model and the efficient market hypothesis, the value for the "P_0" term in the DCF Model should technically be the current stock price, rather than an average.

Q. Why did you use a 30-day average for the current stock price input?

A. Using a short-term average of stock prices for the current stock price input adheres to market efficiency principles while avoiding any irregularities that may arise from using a single current stock price. In the context of a utility rate proceeding there is a significant length of time from when an application is filed, and testimony is due. Choosing a current stock price for one particular day could raise a separate issue concerning which day was chosen to be used in the analysis. In addition, a single stock price on a particular day may be unusually high or low. It is arguably ill-advised to use a single stock price in a model

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[39] Exhibit DJG-3.

[40] *See* Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Vol. 25, No. 2 The Journal of Finance 383 (1970).

that is ultimately used to set rates for several years, especially if a stock is experiencing some volatility. Thus, it is preferable to use a short-term average of stock prices, which represents a good balance between adhering to well-established principles of market efficiency while avoiding any unnecessary contentions that may arise from using a single stock price on a given day. The stock prices I used in my DCF analysis are based on 30-day averages of adjusted closing stock prices for each company in the proxy group.[41]

B. Dividend

Q. Describe how you determined the dividend input of the DCF Model.

A. The dividend term in the Quarterly Approximation DCF Model is the current quarterly dividend per share (d_0). I obtained the most recent quarterly dividend paid for each proxy company.[42] The Quarterly Approximation DCF Model assumes that the company increases its dividend payments each quarter. Thus, the model assumes that each quarterly dividend is greater than the previous one by $(1 + g)^{0.25}$. This expression could be described as the dividend quarterly growth rate, where the term "g" is the growth rate and the exponential term "0.25" signifies one quarter of the year.

Q. Does the Quarterly Approximation DCF Model result in the highest cost of equity in this case relative to other DCF Models, all else held constant?

A. Yes. The Quarterly Approximation DCF Model I employed in this case results in a higher DCF cost of equity estimate than the annual or semi-annual DCF Models due to the

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[41] Exhibit DJG-3. Adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices. The adjusted price provides an accurate representation of the firm's equity value beyond the mere market price because it accounts for stock splits and dividends.

[42] Exhibit DJG-4. Nasdaq Dividend History, http://www.nasdaq.com/quotes/dividend-history.aspx.

quarterly compounding of dividends inherent in the model. In essence, the Quarterly Approximation DCF Model I used results in the highest cost of equity estimate, all else held constant.

Q. Are the stock price and dividend inputs for each proxy company a significant issue in this case?

A. No. Although my stock price and dividend inputs are more recent than those used by Mr. Moul, there is not a statistically significant difference between them because utility stock prices and dividends are generally quite stable. This is another reason that cost of capital models such as the CAPM and the DCF Model are well-suited to be used for utilities. The differences between my DCF Model and Mr. Moul's DCF Model are primarily driven by differences in our growth rate estimates, which are further discussed below.

C. <u>Growth Rate</u>

Q. Summarize the growth rate input in the DCF Model.

A. The most critical input in the DCF Model is the growth rate. Unlike the stock price and dividend inputs, the growth rate input (g) must be estimated. As a result, the growth rate is often the most contentious DCF input in utility rate cases. The DCF model used in this case is based on the constant growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a long-term growth rate. As stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a constant rate forever. Thus, the growth rate term in the constant growth DCF model is often called the "constant," "stable," or "terminal" growth rate. For young, high-growth firms, estimating the growth rate to be used in the model can be especially difficult, and may require the use of multi-stage growth models. For mature, low-growth firms such as utilities, however, estimating the terminal growth rate is more transparent. The growth term of the DCF Model is one of the most important, yet apparently most misunderstood, aspects of cost of equity estimations in utility regulatory proceedings. Therefore, I have devoted a more detailed explanation of this issue in the following sections, which are organized as follows:

(1) The Various Determinants of Growth

(2) Reasonable Estimates for Long-Term Growth

(3) Quantitative vs. Qualitative Determinants of Utility Growth: Circular References, "Flatworm" Growth, and the Problem with Analysts' Growth Rates

(4) Growth Rate Recommendation

1. <u>The Various Determinants of Growth</u>

Q. Describe the various determinants of growth.

A. Although the DCF Model directly considers the growth of dividends, there are a variety of growth determinants that should be considered when estimating growth rates. It should be noted that these various growth determinants are used primarily to determine the short-term growth rates in multi-stage DCF models. For utility companies, it is necessary to focus primarily on long-term growth rates, which are discussed in the following section. That is not to say that these growth determinants cannot be considered when estimating long-term growth; however, as discussed below, long-term growth must be constrained much more than short-term growth, especially for young firms with high growth opportunities. Additionally, I briefly discuss these growth determinants here because it may reveal some of the source of confusion in this area.

A. Historical Growth

Looking at a firm's actual historical experience may theoretically provide a good starting point for estimating short-term growth. However, past growth is not always a good indicator of future growth. Some metrics that might be considered here are a historical growth in revenues, operating income, and net income. Since dividends are paid from earnings, estimating historical earnings growth may provide an indication of future earnings and dividend growth. In general, however, revenue growth tends to be more consistent and predictable than earnings growth because it is less likely to be influenced by accounting adjustments.[43]

B. Analyst Growth Rates

Analyst growth rates refer to short-term projections of earnings growth published by institutional research analysts such as Value Line and Bloomberg. A more detailed discussion of analyst growth rates, including the problems with using them in the DCF Model to estimate utility cost of equity, is provided in a later section.

C. Fundamental Determinants of Growth

Fundamental growth determinants refer to firm-specific financial metrics that arguably provide better indications of near-term sustainable growth. One such metric for fundamental growth considers the return on equity and the retention ratio. The idea behind

[43] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 279 (3rd ed., John Wiley & Sons, Inc. 2012).

this metric is that firms with high ROEs and retention ratios should have greater opportunities for growth.[44]

Q. Did you use any of these growth determinants in your DCF Model?

A. No. Primarily, these growth determinants discussed above would provide better indications of short- to mid-term growth for firms with average to high growth opportunities. Utilities, however, are mature, low-growth firms. While it may not be unreasonable on its face to use any of these growth determinants for the growth input in the DCF Model, we must keep in mind that the stable growth DCF Model considers only <u>long-term</u> growth rates, which are constrained by certain economic factors, as discussed further below.

2. <u>Reasonable Estimates for Long-Term Growth</u>

Q. Describe what is meant by long-term growth.

A. In order to make the DCF Model a viable, practical model, an infinite stream of future cash flows must be estimated and then discounted back to the present. Otherwise, each annual cash flow would have to be estimated separately. Some analysts use "multi-stage" DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being constant. However, it is not necessary to use multi-stage DCF Models to analyze the cost of equity of regulated utility companies. This is because regulated utilities are already in their "terminal," low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical service

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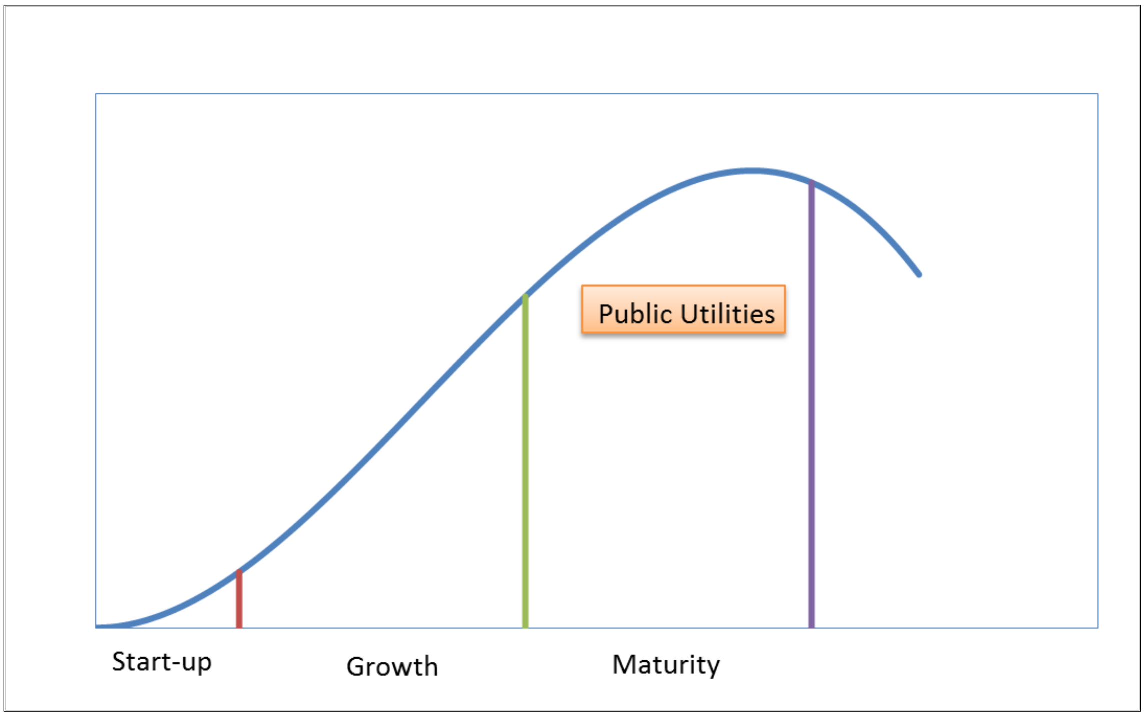
[44] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 279 (3rd ed., John Wiley & Sons, Inc. 2012).

territories and limited primarily by ratepayer and load growth within those territories. The figure below illustrates the well-known business/industry life-cycle pattern.

Figure 6:
Industry Life Cycle



In an industry's early stages, there are ample opportunities for growth and profitable reinvestment. In the maturity stage however, growth opportunities diminish, and firms choose to pay out a larger portion of their earnings in the form of dividends instead of reinvesting them in operations to pursue further growth opportunities. Once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one terminal, long-term growth rate.

Q. Is it true that the terminal growth rate cannot exceed the growth rate of the economy, especially for a regulated utility company?

A. Yes. A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates.[45] Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Damodaran: "[i]f a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value."[46]

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is <u>less</u> than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding into new and developing markets, utility operating companies with defined service territories cannot do any of these things to grow. Gross Domestic Product ("GDP") is one of the most widely used measures of economic production and is used to measure aggregate economic growth. According to the Congressional Budget Office's Budget Outlook, the long-term forecast for nominal U.S. GDP growth is about 4%, which includes an inflation rate of 2%.[47] For mature companies in mature industries, such as utility companies, the terminal growth rate

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[45] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

[46] *Id.*

[47] Congressional Budget Office Long-Term Budget Outlook, <u>https://www.cbo.gov/publication/56977</u> (last accessed June 22, 2021).

will likely fall between the expected rate of inflation and the expected rate of nominal GDP growth. Thus, UGI's terminal growth rate is between 2% and 4%.

Q. Is it reasonable to assume that the terminal growth rate will not exceed the risk-free rate?

A. Yes. In the long term, the risk-free rate will converge on the growth rate of the economy. For this reason, financial analysts sometimes use the risk-free rate for the terminal growth rate value in the DCF model.[48] I discuss the risk-free rate in further detail later in this testimony.

Q. Please summarize the various long-term growth rate estimates that can be used as the terminal growth rate in the DCF Model.

A. The reasonable long-term growth rate determinants are summarized as follows:

1. Nominal GDP Growth
2. Real GDP Growth
3. Inflation
4. Current Risk-Free Rate

Any of the foregoing growth determinants could provide a basis for a reasonable input for the terminal growth rate in the DCF Model for a utility company, including UGI. In general, we should expect that utilities will, at the very least, grow at the rate of projected inflation. However, the long-term growth rate of any U.S. company, especially utilities, will be constrained by nominal U.S. GDP growth.

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[48] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 307 (3rd ed., John Wiley & Sons, Inc. 2012).

3. <u>Qualitative Growth: The Problem with Analysts' Growth Rates</u>

Q. Describe the differences between "quantitative" and "qualitative" growth determinants.

A. Assessing "quantitative" growth simply involves mathematically calculating a historic metric for growth (such as revenues or earnings) or calculating various fundamental growth determinants using certain figures from a firm's financial statements (such as ROE and the retention ratio). However, any thorough assessment of company growth should be based upon a "qualitative" analysis. Such an analysis would consider specific strategies that company management will implement to achieve real sustainable growth in earnings. Therefore, it is important to begin the analysis of UGI's growth rate with this simple, qualitative question: how is this regulated utility going to achieve a real sustained growth in earnings? If this question were asked of a competitive firm, there could be several answers depending on the type of business model, such as launching a new product line, franchising, rebranding to target a new demographic, or expanding into a developing market. Regulated utilities, however, cannot engage in these potential growth opportunities.

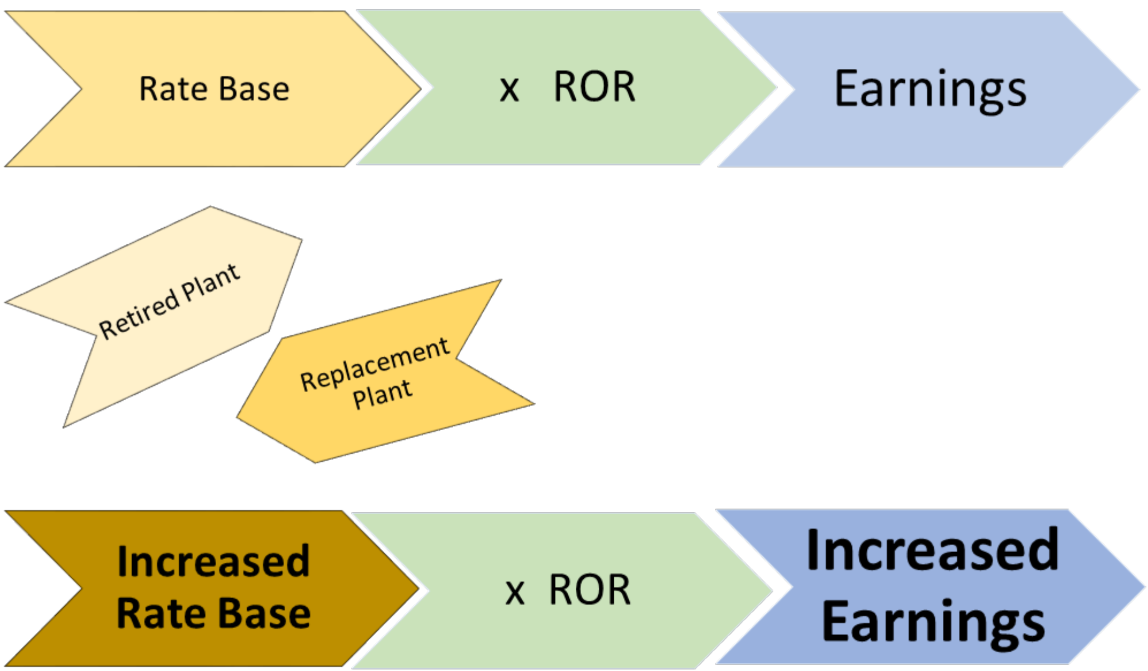
Q. Why is it especially important to emphasize real, qualitative growth determinants when analyzing whether a growth rate is fair for a regulated utility?

A. While qualitative growth analysis is important regardless of the entity being analyzed, it is especially important in the context of utility ratemaking. This is because the rate base rate of return model inherently possesses two factors that can contribute to distorted views of utility growth when considered exclusively from a quantitative perspective. These two factors are: (1) rate base and (2) the awarded ROE. I will discuss each factor further below. It is important to keep in mind that the ultimate objective of this analysis is to provide a foundation upon which to base the fair rate of return for the utility. Thus, we should strive to ensure that each individual component of the financial models used to estimate the cost of equity are also fair. If we consider only quantitative growth determinants, it may lead to projected growth rates that are overstated and ultimately unfair, because they result in inflated cost of equity estimates.

Q. How does rate base relate to growth determinants for utilities?

A. Under the rate base rate of return model, a utility's rate base is multiplied by its awarded rate of return to produce the required level of operating income. Therefore, increases to rate base generally result in increased earnings. Thus, utilities have a natural financial incentive to increase rate base. In short, utilities have a financial incentive to increase rate base regardless of whether such increases are driven by a corresponding increase in demand. A good, relevant example of this is seen in the early retirement of old, but otherwise functional coal plants in response to environmental regulations and replacing them with new generation assets. Under these circumstances, utilities have been able to increase their rate bases by a far greater extent than what any concurrent increase in demand would have required. In other words, utilities grew their earnings by simply retiring old assets and replacing them with new assets. This is not "real" or "sustainable" growth. If the tail of a flatworm is removed and regenerated, it does not mean the flatworm actually grew. Likewise, if a competitive, unregulated firm announced plans to close production plants and replace them with new plants, it would not be considered a real determinant of growth unless analysts believed this decision would directly result in increased market share for the company and a real opportunity for sustained increases in revenues and earnings. In the case of utilities, the mere replacement of "old plant" with "new plant" does not increase market share, attract new ratepayers, create franchising opportunities, or allow utilities to penetrate developing markets, but may result in short-term, quantitative earnings growth. However, this "flatworm growth" in earnings was merely the quantitative byproduct of the rate base rate of return model, and not an indication of real or qualitative growth and, therefore, using that data alone to estimate a growth rate is not fair. The following diagram in the figure below illustrates this concept.

Figure 7:
Analysts' Earnings Growth Projections: The "Flatworm Growth" Problem

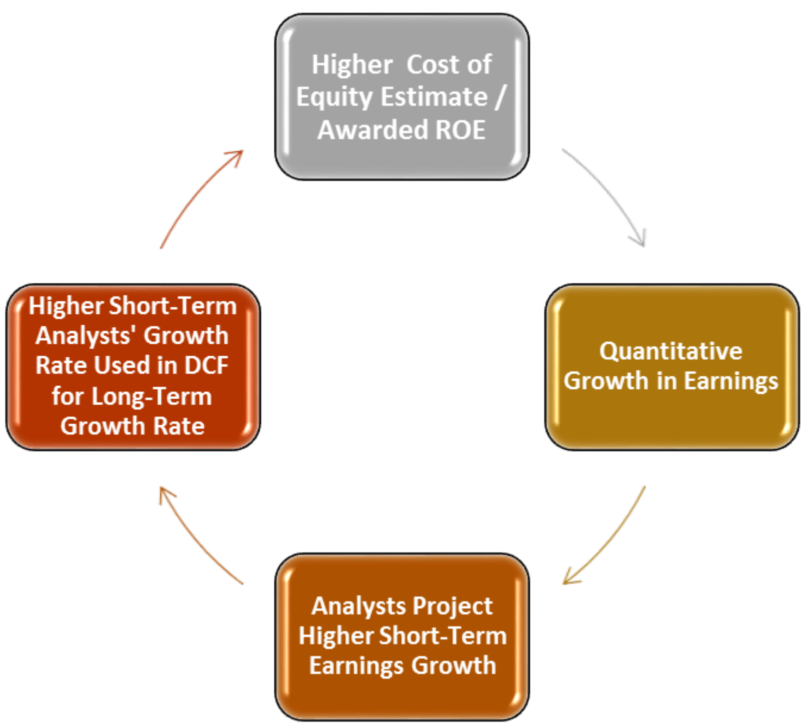


Of course, utilities might sometimes add "new plant" to meet a modest growth in ratepayer demand. However, as the foregoing discussion demonstrates, it would be more appropriate to consider load growth projections and other qualitative indicators, rather than mere increases to rate base or earnings, to attain a fair assessment of growth.

Q. Please discuss the other way in which analysts' earnings growth projections do not provide indications of real, qualitative growth for regulated utilities.

A. If we give undue weight to analysts' projections for utilities' earnings growth, it will not provide an accurate reflection of real, qualitative growth because a utility's earnings are heavily influenced by the ultimate figure that all this analysis is supposed to help us estimate: the awarded return on equity. This creates a circular reference problem or feedback loop. In other words, if a regulator awards an ROE that is above market-based cost of capital (which is often the case, as discussed above), this could lead to higher short-term growth rate projections from analysts. If these same inflated, short-term growth rate estimates are used in the DCF Model (as they often are by utility witnesses), it could lead to higher awarded ROEs; and the cycle continues, as illustrated in the figure below.

Figure 8:
Analysts' Earnings Growth Projections: The "Circular Reference" Problem



Therefore, it is not advisable to simply consider the quantitative growth projections published by analysts, as this practice will not necessarily provide fair indications of real, sustainable utility growth.

Q. Are there any other problems with relying on analysts' growth projections?

A. Yes. While the foregoing discussion shows two reasons why we cannot rely on analysts' growth rate projections to provide fair, qualitative indicators of utility growth in a stable growth DCF Model, the third reason is perhaps the most obvious and undisputable. Various institutional analysts—such as Zacks, Value Line, and Bloomberg—publish estimated projections of earnings growth for utilities. These estimates are short-term growth rate projections, ranging from 3 to 10 years. However, many utility ROE analysts inappropriately insert these short-term growth projections into the DCF Model as if they were *long-term* growth rate projections. For example, assume that an analyst at Bloomberg estimates that a utility's earnings will grow by 7% per year over the next 3 years. This analyst may have based this short-term forecast on a utility's plans to replace depreciated rate base (*i.e.*, "flatworm" growth) or on an anticipated awarded return that is above market-based cost of equity (*i.e.*, the "circular reference" problem). When a utility witness uses this figure in a DCF Model, however, it is the witness, not the Bloomberg analyst, that is testifying to the regulator that the utility's earnings will qualitatively grow by 7% per year over the long-term, which is an unrealistic assumption and a fundamentally different conclusion than that of the Bloomberg analyst.

4. <u>Long-Term Growth Rate Recommendation</u>

Q. Describe the growth rate input used in your DCF Model.

A. I considered various qualitative determinants of growth for UGI, along with the maximum allowed growth rate under basic principles of finance and economics. The following chart in the figure below shows three of the long-term growth determinants discussed in this section.[49]

Figure 9:
Terminal Growth Rate Determinants

Terminal Growth Determinants	Rate
Nominal GDP	3.8%
Real GDP	1.8%
Inflation	2.0%
Risk Free Rate	2.4%
Highest	**3.8%**

For the long-term growth rate in my DCF model, I selected the maximum, reasonable long-term growth rate of 3.8%, which means my model assumes that UGI's qualitative growth in earnings will qualitatively match the nominal growth rate of the entire U.S. economy over the long run – a charitable assumption.

Q. Please describe the final results of your DCF Model.

A. I used the Quarterly Approximation DCF Model discussed above to estimate UGI's cost of equity capital. I obtained an average of reported dividends and stock prices from the

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[49] Exhibit DJG-5.

proxy group, and I used a reasonable terminal growth rate estimate for UGI. My DCF Model cost of equity estimate for UGI is 6.7%.[50]

D. Response to Mr. Moul's DCF Model

Q. Mr. Moul's DCF Model yielded a notably higher result. Did you find any problems with his analysis?

A. Yes. Mr. Moul's DCF Model produced cost of equity result of 11.21%, which includes a "leverage adjustment" of 0.95%[51]. As mentioned earlier, the results of Mr. Moul's DCF Model are overstated primarily because of a fundamental error regarding his growth rate inputs and his leverage adjustment.

Q. Describe the problems with Mr. Moul's assumed long-term growth input.

A. Mr. Moul assumes a projected growth rate of 6.75% in his DCF Model.[52] In arriving at this growth rate input, Mr. Moul considered growth rates as high as 10.5% for the proxy group,[53] which is <u>more than double</u> the long-term nominal U.S. GDP growth. This means Mr. Moul's growth rate assumption violates the basic principle that no company can grow at a greater rate than the economy in which it operates *over the long-term*, especially a regulated utility company with a defined service territory. Furthermore, Mr. Moul relies on short-term, quantitative growth estimates published by analysts to support his assumptions. Mr. Moul acknowledges that his growth rate projections cover only a five-

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[50] Exhibit DJG-6.

[51] Direct Testimony of Paul R. Moul, p. 37.

[52] *Id*.

[53] Direct testimony of Paul R. Moul, Exhibit PRM-1, Sch. 9.

year period.[54] This period of time is not sufficient for a long-term estimate. As discussed above, these analysts' estimates are inappropriate to use in the DCF Model as long-term growth rates because they are estimates for short-term growth. For example, Mr. Moul assumes a long-term growth rate estimate of 10.5% for NextEra Energy (among other estimates), as reported by Value Line Investment Survey.[55] This means that an analyst at Value Line apparently thinks that NextEra's dividends will quantitatively increase by 10.5% each year over the next <u>several</u> years (*i.e.*, the short-term). However, it is Mr. Moul, not the commercial analyst, who is suggesting to the Commission that NextEra's dividends will increase by 10.5% (<u>more than double</u> U.S. GDP growth) each year, every year, for many decades into the future (*i.e.*, long-term growth).[56] Again, Mr. Moul is extrapolating the analyst's conclusions well beyond what the analyst actually said. Furthermore, this assumption is simply not realistic, and it contradicts fundamental concepts of long-term growth. Many of Mr. Moul's other short-term growth rate estimates also exceed projected U.S. GDP growth.

Q. Please describe Mr. Moul's leverage adjustment.

A. According to Mr. Moul, a leverage adjustment is necessary when "the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting."[57]

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[54] Direct testimony of Paul R. Moul, p. 29, lines 21-23.

[55] Direct testimony of Paul R. Moul, Exhibit PRM-1, Sch. 9.

[56] Technically, the constant growth rate in the DCF Model grows dividends each year to infinity. Yet even if we assumed that the growth rate applied to only a few decades, the annual growth rate would still be too high to be considered realistic.

[57] Direct testimony of Paul R. Moul, p. 35, lines 23-25.

Q. Have you ever seen or heard of a witness apply a leverage adjustment like the one Mr. Moul is proposing?

A. No. I have testified in numerous proceedings on the issue of cost of capital and other regulatory issues and have reviewed extensive amounts of testimony from many witnesses on cost of capital issues. Yet I cannot recall a witness applying a "leverage adjustment" in the way Mr. Moul is proposing in this case (other than Mr. Moul's proposed leverage adjustments in prior cases).

Q. Does the original DCF model have an input for a leverage adjustment?

A. No. The DCF model has been used by investors, analysts, managers, and academics for decades to assist with pricing assets and estimate the cost of equity of various assets and projects. I have not seen a variation of the DCF model in any financial textbook or other reliable source that presents the model with a "leverage adjustment" input similar to the way in which Mr. Moul presents the model in his testimony.

Q. Has the Commission rejected Mr. Moul's leverage adjustment in prior cases?

A. Yes.[58] In PPL's 2012 rate case, Mr. Moul proposed a substantially similar leverage adjustment. The Commission found that "[f]or the reasons developed by the OCA and I&E, the Company's leverage adjustment should be denied."[59]

Q. Have other commissions recently rejected Mr. Moul's leverage adjustment?

A. Yes. Recently, in the Application of Palmetto Wastewater Reclamation ("PWR"), the Public Service Commission of South Carolina rejected Mr. Moul's leverage adjustment.[60]

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[58] *Pa. P.U.C. v. PPL Elec. Util. Corp.*, Docket No. R-2012-2290597, Order, 52 (Dec. 28, 2012), p. 52 of 105.

[59] *Id*. at p. 52.

[60] *In re Application of Palmetto Wastewater Reclamation, Inc. for an Adjustment of Rates and Charges*, 2021 S.C. PUC LEXIS *1, *23 (Dec. 21, 2021).

Relying in part on my testimony in the PWR case, the South Carolina commission agreed that "Mr. Moul's 0.97% leverage adjustment is not appropriate."[61]

Q. Do you agree with Mr. Moul's leverage adjustment?

A. No. Mr. Moul's proposed leverage adjustment is entirely unnecessary and inappropriate, and it has the effect of further inflating a DCF result that is already overestimated. Mr. Moul's leverage adjustment is based on the Hamada formula, which is further discussed below.

Q. What is the premise of the Hamada formula?

A. The Hamada formula can be used to analyze changes in a firm's cost of capital as it adds or reduces financial leverage, or debt, in its capital structure by starting with an "unlevered" beta and then "relevering" the beta at different debt ratios. As leverage increases, equity investors bear increasing amounts of risk, leading to higher betas. Before the effects of financial leverage can be accounted for, however, the effects of leverage must first be removed, which is accomplished through the Hamada formula. The Hamada formula for unlevering beta is stated as follows:[62]

[61] *Id*.

[62] Damodaran *supra* n. 18, at 197. This formula was originally developed by Hamada in 1972.

Equation 3:
Hamada Formula

$$\beta_U = \frac{\beta_L}{\left[1 + (1 - T_c)\left(\frac{D}{E}\right)\right]}$$

where: β_U = *unlevered beta (or "asset" beta)*
β_L = *average levered beta of proxy group*
T_C = *corporate tax rate*
D = *book value of debt*
E = *book value of equity*

Using this equation, the beta for the firm can be unlevered, and then "relevered" based on various debt ratios (by rearranging this equation to solve for β_L).

Q. Did Mr. Moul apply the Hamada formula correctly?

A. No. Mr. Moul's application of the Hamada formula is incorrect. I conducted the Hamada Model and present my results in my exhibits.[63] Using the Company's proposed capital structure and the levered betas published by Value Line, I calculate an unlevered beta of 0.53. When that beta is relevered to my proposed debt ratio of 50%, I calculate a cost of equity of 7.62%. However, conducting the Hamada formula in this fashion is not necessary in this case. This is because we are taking inputs from the proxy group, such as stock prices, dividends, and betas in order to estimate the cost of equity of UGI. The indicated cost of equity from the financial models are necessarily connected to the capital structures of the proxy group. In other words, the fact that UGI has proposed a debt ratio that is lower than the average debt ratio of the proxy group should not necessarily result in an increase in the Company's indicated cost of equity when we "unlever" the proxy beta based on UGI's unreasonably low debt ratio, and then relever it to the debt ratio of the proxy group

[63] *See* Exhibit DJG-17.

that was influencing the other cost of equity model inputs we relied upon. While the Hamada formula can be a useful tool to show how the cost of equity can change at different levels of leverage, the formula is simply not necessary to estimate UGI's cost of equity in this case. It is not surprising that the CAPM and DCF Models do not include inputs for leverage adjustments. It is also not surprising that the vast majority of ROE witnesses do not include separate leverage adjustments to their cost of equity models in the way Mr. Moul has done in this case. The Commission should reject Mr. Moul's leverage adjustment in this case, as it has done in prior cases.

Q. Have you quantified the financial impact to ratepayers that Mr. Moul's leverage adjustment would have?

A. Yes. As addressed in the direct testimony of OCA witness Mugrace, an increase of 0.95% to the ROE for Mr. Moul's inappropriate leverage adjustment would increase the revenue requirement by $23.5 million.

VI. CAPM ANALYSIS

Q. Describe the CAPM.

A. The CAPM is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.[64] The CAPM estimates this expected return. The various assumptions, theories, and equations involved in the CAPM are discussed further in Appendix B. Using the CAPM to estimate the cost of equity of a regulated utility is consistent with the legal standards governing the fair rate of return. The U.S. Supreme Court has recognized that "the amount of risk in the business is a most important factor"

[64] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277–93 (Management Science IX 1963).

in determining the allowed rate of return,[65] and that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."[66] The CAPM is a useful model because it directly considers the amount of risk inherent in a business.

Q. Describe the inputs for the CAPM.

A. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the equity risk premium. Here is the CAPM formula:

Equation 4:
Basic CAPM

Cost of Equity = Risk-free Rate + (Beta × Equity Risk Premium)

Each input is discussed separately below.

A. The Risk-Free Rate

Q. Explain the risk-free rate.

A. The first term in the CAPM is the risk-free rate (R_F). The risk-free rate is simply the level of return investors can achieve without assuming any risk. The risk-free rate represents the bare minimum return that any investor would require on a risky asset. Even though no investment is technically void of risk, investors often use U.S. Treasury securities to represent the risk-free rate because they accept that those securities essentially contain no

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[65] *Wilcox*, 212 U.S. at 48.

[66] *Hope Natural Gas Co*., 320 U.S. at 603.

default risk. The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

Q. Is it preferable to use the yield on long-term Treasury bonds for the risk-free rate in the CAPM?

A. Yes. In valuing an asset, investors estimate cash flows over long periods of time. Common stock is viewed as a long-term investment, and the cash flows from dividends are assumed to last indefinitely. Thus, short-term Treasury Bill yields are rarely used in the CAPM to represent the risk-free rate. Short-term rates are subject to greater volatility and thus can lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to represent the risk-free rate in the CAPM. I considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury Bonds in my risk-free rate estimate, which resulted in a risk-free rate of 2.4%.[67]

B. The Beta Coefficient

Q. How is the beta coefficient used in this model?

A. As discussed above, beta represents the sensitivity of a given security to movements in the overall market. The CAPM states that in efficient capital markets, the expected risk premium on each investment is proportional to its beta. Recall that a security with a beta greater (or less) than one is more (or less) risky than the market portfolio. An index such as the S&P 500 Index is used as a proxy for the market portfolio. The historical betas for publicly traded firms are published by various institutional analysts. Beta may also be calculated through a linear regression analysis, which provides additional statistical

[67] Exhibit DJG-7.

information about the relationship between a single stock and the market portfolio. As discussed above, beta also represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than 1.0 are relatively more sensitive to market risk than the average stock. For example, if the market increases (or decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (or decrease) by 1.5%. In contrast, stocks with betas of less than 1.0 are less sensitive to market risk. For example, if the market increases (or decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (or decrease) by 0.5%.

Q. Describe the source for the betas you used in your CAPM analysis.

A. I used betas recently published by Value Line Investment Survey. The average beta for the proxy group is less than 1.0. Thus, we have an objective measure to prove the well-known concept that utility stocks are generally less risky than the average stock in the market. While there is evidence suggesting that betas published by sources such as Value Line may actually overestimate the risk of utilities (and thus overestimate the CAPM), I used the betas published by Value Line to be conservative.[68]

C. <u>The Equity Risk Premium</u>

Q. Describe the Equity Risk Premium (ERP).

A. The final term of the CAPM is the ERP, which is the required return on the market portfolio less the risk-free rate ($R_M - R_F$). In other words, the ERP is the level of return investors expect above the risk-free rate in exchange for investing in risky securities. Many experts

[68] Exhibit DJG-8; *see also* Appendix B for a more detailed discussion of raw beta calculations and adjustments.

would agree that "the single most important variable for making investment decisions is the equity risk premium."[69] Likewise, the ERP is arguably the single most important factor in estimating the cost of capital in this matter. There are three basic methods that can be used to estimate the ERP: (1) calculating a historical average; (2) taking a survey of experts; and (3) calculating the implied ERP. I will discuss each method in turn, noting advantages and disadvantages of these methods.

1. <u>Historical Average</u>

Q. Describe the historical ERP.

A. The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period of time. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because it is easy to obtain. However, there are disadvantages to relying on the historical ERP.

Q. What are the limitations of relying solely on a historical average to estimate the current or forward-looking ERP?

A. Many investors use the historic ERP because it is convenient and easy to calculate. What matters in the CAPM model, however, is not the actual risk premium from the past, but rather the current and forward-looking risk premium.[70] Some investors may think that a historic ERP provides some indication of the prospective risk premium; however, there is empirical evidence to suggest the prospective, forward-looking ERP is actually <u>lower</u> than the historical ERP. In a landmark publication on risk premiums around the world, *Triumph*

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[69] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 4 (Princeton University Press 2002).

[70] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

of the Optimists, the authors suggest through extensive empirical research that the prospective ERP is lower than the historical ERP.[71] This is due in large part to what is known as "survivorship bias" or "success bias" – a tendency for failed companies to be excluded from historical indices.[72] From their extensive analysis, the authors make the following conclusion regarding the prospective ERP: "[t]he result is a forward-looking, geometric mean risk premium for the United States . . . of around 2½ to 4 percent and an arithmetic mean risk premium . . . that falls within a range from a little below 4 to a little above 5 percent."[73] Indeed, these results are lower than many reported historical risk premiums. Other noted experts agree:

> The historical risk premium obtained by looking at U.S. data is biased upwards because of survivor bias. . . . The true premium, it is argued, is much lower. This view is backed up by a study of large equity markets over the twentieth century (*Triumph of the Optimists*), which concluded that the historical risk premium is closer to 4%.[74]

Regardless of the variations in historic ERP estimates, many scholars and practitioners agree that simply relying on a historic ERP to estimate the risk premium going forward is not ideal. Fortunately, "a naïve reliance on long-run historical averages is not the only approach for estimating the expected risk premium."[75]

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[71] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 194 (3rd ed., South Western Cengage Learning 2010).

[72] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 34 (Princeton University Press 2002).

[73] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 194 (Princeton University Press 2002).

[74] Aswath Damodaran, *Equity Risk Premiums: Determinants, Estimation and Implications – The 2015 Edition* 17 (New York University 2015).

[75] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 330 (3rd ed., South Western Cengage Learning 2010).

Q. Did you rely on the historical ERP as part of your CAPM analysis in this case?

A. No. Due to the limitations of this approach, I relied on the ERP reported in expert surveys and the implied ERP method discussed below.

2. Expert Surveys

Q. Describe the expert survey approach to estimating the ERP.

A. As its name implies, the expert survey approach to estimating the ERP involves conducting a survey of experts including professors, analysts, chief financial officers, and other executives around the country and asking them what they think the ERP is. The IESE Business School conducts such a survey each year. Their 2021 expert survey reported an average ERP of 5.5%.[76]

3. Implied ERP

Q. Describe the implied ERP approach.

A. The third method of estimating the ERP is arguably the best. The implied ERP relies on the stable growth model proposed by Gordon, often called the "Gordon Growth Model," which is a basic stock valuation model widely used in finance for many years.[77] This model is a mathematical derivation of the DCF Model. In fact, the underlying concept in both models is the same: the current value of an asset is equal to the present value of its future cash flows. Instead of using this model to determine the discount rate of one company, we

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[76] Pablo Fernandez, Pablo Linares & Isabel F. Acin, *Market Risk Premium used in 171 Countries in 2016: A Survey with 6,932 Answers*, at 3 (IESE Business School 2015), copy available at http://www.valumonics.com/wp-content/uploads/2017/06/Discount-rate-Pablo-Fern%C3%A1ndez.pdf. IESE Business School is the graduate business school of the University of Navarra. IESE offers Master of Business Administration (MBA), Executive MBA and Executive Education programs. IESE is consistently ranked among the leading business schools in the world.

[77] Myron J. Gordon and Eli Shapiro, *Capital Equipment Analysis: The Required Rate of Profit* 102–10 (Management Science Vol. 3, No. 1 Oct. 1956).

can use it to determine the discount rate for the entire market by substituting the inputs of the model. Specifically, instead of using the current stock price (P_0), we will use the current value of the S&P 500 (V_{500}). Similarly, instead of using the dividends of a single firm, we will consider the dividends paid by the entire market. Additionally, we should consider potential dividends. In other words, stock buybacks should be considered in addition to paid dividends, as stock buybacks represent another way for the firm to transfer free cash flow to shareholders. Focusing on dividends alone without considering stock buybacks could understate the cash flow component of the model, and ultimately understate the implied ERP. The market dividend yield plus the market buyback yield gives us the gross cash yield to use as our cash flow in the numerator of the discount model. This gross cash yield is increased each year over the next five years by the growth rate. These cash flows must be discounted to determine their present value. The discount rate in each denominator is the risk-free rate (R_F) plus the discount rate (K). The following formula shows how the implied return is calculated. Since the current value of the S&P is known, we can solve for K: the implied market return.[78]

Equation 5:
Implied Market Return

$$V_{500} = \frac{CY_1(1+g)^1}{(1+R_F+K)^1} + \frac{CY_2(1+g)^2}{(1+R_F+K)^2} + \cdots + \frac{CY_5(1+g)^5 + TV}{(1+R_F+K)^5}$$

where:	V_{500}	=	*current value of index (S&P 500)*
	CY_{1-5}	=	*average cash yield over last five years (includes dividends and buybacks)*
	g	=	*compound growth rate in earnings over last five years*
	R_F	=	*risk-free rate*
	K	=	*implied market return (this is what we are solving for)*
	TV	=	*terminal value* $= CY_5\,(1+R_F)\,/\,K$

[78] *See* Exhibit DJG-9 for detailed calculation.

The discount rate is called the “implied” return here because it is based on the current value of the index as well as the value of free cash flow to investors projected over the next five years. Thus, based on these inputs, the market is “implying” the expected return; or in other words, based on the current value of all stocks (the index price), and the projected value of future cash flows, the market is telling us the return expected by investors for investing in the market portfolio. After solving for the implied market return (K), we simply subtract the risk-free rate from it to arrive at the implied ERP.

Equation 6:
Implied Equity Risk Premium

$$Implied\ Expected\ Market\ Return - R_F = Implied\ ERP$$

Q. Discuss the results of your implied ERP calculation.

A. After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of 7.0%. I subtracted the risk-free rate to arrive at the implied equity risk premium of 4.9%.[79] Dr. Damodaran, one of the world’s leading experts on the ERP, promotes the implied ERP method discussed above. He calculates monthly and annual implied ERPs with this method and publishes

[79] Exhibit DJG-9.

his results. Dr. Damodaran's average ERP estimate for June 2021 using several implied ERP variations was 4.8%.[80]

Q. What are the results of your final ERP estimate?

A. For the final ERP estimate I used in my CAPM analysis, I considered the results of the ERP surveys along with the implied ERP calculations and the ERP reported by Duff & Phelps.[81] The results are presented in the following figure:

Figure 10:
Equity Risk Premium Results

IESE Business School Survey	5.5%
Duff & Phelps Report	5.5%
Damodaran (average)	4.8%
Garrett	4.9%
Average	**5.2%**
Highest	**5.5%**

While it would be arguably reasonable to select any one of these ERP estimates to use in the CAPM, to be conservative, I selected the highest ERP estimate of 5.5% to use in my CAPM analysis. All else held constant, a higher ERP used in the CAPM will result in a higher cost of equity estimate.

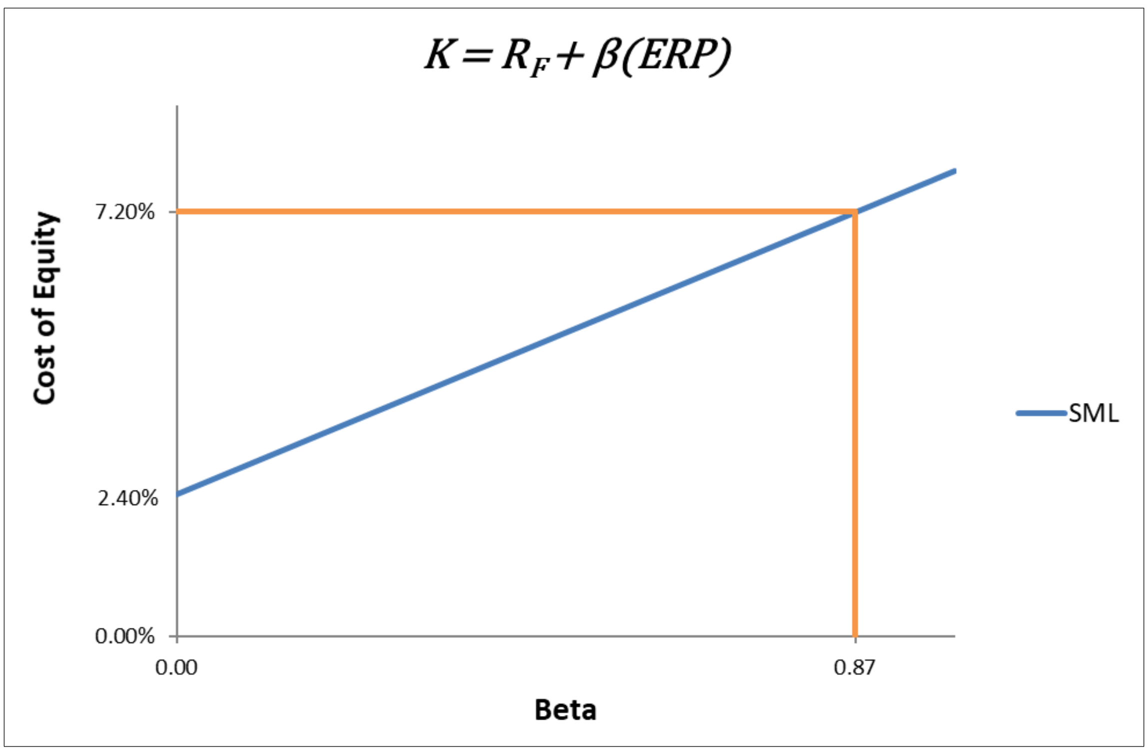
[80] Aswath Damodaran, *Implied Equity Risk Premium Update*, DAMODARAN ONLINE http://pages.stern.nyu.edu/~adamodar/.

[81] Exhibit DJG-10.

1 **Q. Please explain the final results of your CAPM analysis.**

2 A. Using the inputs for the risk-free rate, beta coefficient, and ERP discussed above, I estimate that UGI's CAPM cost of equity is 7.2%.[82] The CAPM may be displayed graphically through what is known as the Security Market Line ("SML"). The following figure shows the expected return (cost of equity) on the y-axis, and the average beta for the proxy group on the x-axis. The SML intercepts the y-axis at the level of the risk-free rate. The slope of the SML is the equity risk premium.

Figure 11:
CAPM Graph



[82] Exhibit DJG-11.

The SML provides the rate of return that will compensate investors for the beta risk of that investment. Thus, at an average beta of 0.87 for the proxy group, the estimated CAPM cost of equity for UGI is 7.2%.

D. Response to Mr. Moul's CAPM Analysis

Q. Mr. Moul's CAPM analysis yields notably higher results. Did you find specific problems with Mr. Moul's CAPM assumptions and inputs?

A. Yes, I did. Mr. Moul's estimates a CAPM cost of equity of 13.55%.[83] Mr. Moul has overestimated each input to the CAPM, and he includes an inappropriate size premium in his model. Each of these problems is discussed further below.

1. Beta

Q. Describe Mr. Moul's beta input to the CAPM.

A. Mr. Moul used a beta of 1.0 in his CAPM.[84] This beta is much higher than the average beta of Mr. Moul's proxy group as reported by Value Line, which is only 0.87.[85] The difference between a beta of 0.87 and 1.0 is significant, especially considering the fact that the beta of the entire market is 1.0. The betas reported by Value Line show that the proxy group is less risky than the market average, while the inflated beta derived by Mr. Moul would indicate the proxy group of utilities is riskier than the market average. Mr. Moul is essentially suggesting that the betas published by Value Line, an objective and widely-used source in utility regulation, are notably underestimated.

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[83] Direct Testimony of Paul R. Moul, p. 42, lines 4-6.

[84] Direct Testimony of Paul R. Moul, p. 43, lines 11-13.

[85] Exhibit DJG-8.

Q. Do you agree with Mr. Moul's beta input?

A. No. By using a beta of 1.0, Mr. Moul is implying that UGI is equal to the risk of the average company in the U.S. market. Such a proposition contradicts any objective or intuitive understanding of a regulated utility's position and operations in the U.S. market. In fact, it is more accurate to say that UGI, and its utility peers, are among the least risky companies in the world. UGI is a regulated monopoly with a captive customer base who provides an essential product with a relatively inelastic demand – operating under a regulatory framework that would essentially prevent it from experiencing financial failure. Competitive firms in the market do not enjoy the same risk-mitigating framework and protections. I have also discussed my disagreement with Mr. Moul's beta input from a technical perspective when I addressed his leverage adjustment above. In short, it is inappropriate to use Value Line betas as a starting point and increasing them to account for leverage. The Commission should reject Mr. Moul's CAPM results for his beta input alone. However, his estimate for the ERP is also unreasonably high, as further discussed below.

2. <u>Equity Risk Premium</u>

Q. Did Mr. Moul rely on a reasonable measure for the ERP?

A. No, he did not. Mr. Moul used an input of 9.78% for the ERP, which is not realistic.[86] The ERP is one of three inputs in the CAPM equation, and it is one of the most important factors for estimating the cost of equity in this case. As discussed above, I used three widely accepted methods for estimating the ERP, including consulting expert surveys, calculating

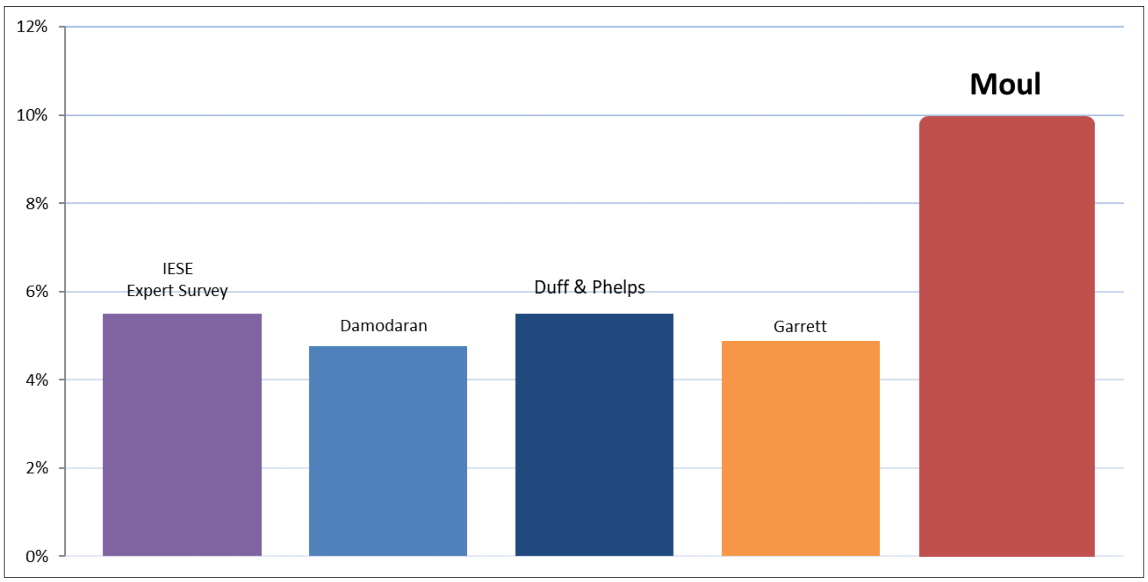
[86] Direct Testimony of Paul R. Moul, p. 45, lines 19-20.

the implied ERP based on aggregate market data, and considering the ERPs published by reputable analysts. The highest ERP found from my research and analysis is only 5.5%.

Q. Please discuss and illustrate how Mr. Moul's ERP compares with other estimates for the ERP.

A. The 2021 IESE Business School expert survey reports an average ERP of 5.5%. Similarly, Duff & Phelps recently estimated an ERP of 5.5%. Dr. Damodaran, one of the leading experts on the ERP, recently estimated an ERP of only 4.8%.[87] The chart in the following figure illustrates that Mr. Moul's ERP estimate is far out of line with other reasonable, objective estimates for the ERP.[88]

Figure 12:
Equity Risk Premium Comparison



[87] Aswath Damodaran, *Implied Equity Risk Premium Update*, DAMODARAN ONLINE, http://pages.stern.nyu.edu/~adamodar/. Dr. Damodaran estimates several ERPs using various assumptions.

[88] The ERP estimated by Dr. Damodaran is the highest of several ERP estimates under slightly differing assumptions.

When compared with other independent sources for the ERP, as well as my estimate, Mr. Moul's ERP estimate is clearly not within the range of reasonableness. As a result, his CAPM cost of equity estimate is overstated.

3. Size Premium

Q. Describe Mr. Moul's size premium adjustment to his CAPM.

A. Mr. Moul adds 1.02% to his CAPM on the basis that UGI is smaller than the proxy group.[89]

Q. Do you agree with Mr. Moul's size premium?

A. No. The "size effect" phenomenon arose from a 1981 study conducted by Banz, which found that "in the 1936 – 1975 period, the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[90] According to Ibbotson, Banz's size effect study was "[o]ne of the most remarkable discoveries of modern finance."[91] Perhaps there was some merit to this idea at the time, but the size effect phenomenon was short lived. Banz's 1981 publication generated much interest in the size effect and spurred the launch of significant new small cap investment funds. However, this "honeymoon period lasted for approximately two years. . . ."[92] After 1983, U.S. small-cap stocks actually underperformed relative to large cap stocks. In other words, the size effect essentially reversed. In *Triumph of the Optimists*, the authors conducted an extensive

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[89] Direct Testimony of Paul R. Moul, p. 46, lines 10-12.

[90] Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks* 3-18 (Journal of Financial Economics 9 (1981)).

[91] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 99 (Morningstar 2015).

[92] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 131 (Princeton University Press 2002).

empirical study of the size effect phenomenon around the world. They found that after the size effect phenomenon was discovered in 1981, it disappeared within a few years:

> It is clear . . . that there was a global reversal of the size effect in virtually every country, with the size premium not just disappearing but going into reverse. Researchers around the world universally fell victim to Murphy's Law, with the very effect they were documenting – and inventing explanations for – promptly reversing itself shortly after their studies were published.[93]

In other words, the authors assert that the very discovery of the size effect phenomenon likely caused its own demise. The authors ultimately concluded that it is "inappropriate to use the term 'size effect' to imply that we should automatically expect there to be a small-cap premium," yet, this is exactly what utility witnesses often do in attempting to artificially inflate the cost of equity with a size premium. Other prominent sources have agreed that the size premium is a dead phenomenon. According to Ibbotson:

> The unpredictability of small-cap returns has given rise to another argument against the existence of a size premium: that markets have changed so that the size premium no longer exists. As evidence, one might observe the last 20 years of market data to see that the performance of large-cap stocks was basically equal to that of small cap stocks. In fact, large-cap stocks have outperformed small-cap stocks in five of the last 10 years.[94]

In addition to the studies discussed above, other scholars have concluded similar results. According to Kalesnik and Beck:

[93] *Id*. at 133.

[94] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 112 (Morningstar 2015).

> Today, more than 30 years after the initial publication of Banz's paper, the empirical evidence is extremely weak even before adjusting for possible biases. . . . The U.S. long-term size premium is driven by the extreme outliers, which occurred three-quarters of a century ago. . . . Finally, adjusting for biases . . . makes the size premium vanish. If the size premium were discovered today, rather than in the 1980s, it would be challenging to even publish a paper documenting that small stocks outperform large ones.[95]

For all of these reasons, the Commission should reject the arbitrary size premium proposed by the Company.

Q. Have other commissions recently rejected Mr. Moul's size adjustment?

A. Yes. Recently, in the Application of Palmetto Wastewater Reclamation ("PWR"), the Public Service Commission of South Carolina rejected Mr. Moul's size premium adjustment.[96] Relying in part on my testimony in the PWR case, the South Carolina commission agreed that "Mr. Moul's 1.02% size adjustment is not appropriate."[97]

VII. <u>OTHER COST OF EQUITY ISSUES</u>

Q. Are there any other issues raised in the Company's testimony to which you would like to respond?

A. Yes. In his testimony, Mr. Moul suggests that certain firm-specific risks and other factors should have an increasing effect on the cost of equity, apparently beyond that which is indicated by the CAPM and DCF Model. Mr. Moul also relies on comparable and expected

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[95] Vitali Kalesnik and Noah Beck, *Busting the Myth About Size* (Research Affiliates 2014), available at <u>https://www.researchaffiliates.com/Our%20Ideas/Insights/Fundamentals/Pages/284_Busting_the_Myth_About_Size.aspx</u> (emphasis added).

[96] Order issued December 21, 2021, Application of Palmetto Wastewater Reclamation, before the Public Service Commission of South Carolina, p. 24.

[97] *Id*.

earnings to support his cost of equity estimate. Finally, Mr. Moul also suggests that management performance should have an increasing effect on UGI's authorized ROE.

A. Firm-Specific Business Risks

Q. Describe Mr. Moul's testimony regarding business risks.

A. In his Direct Testimony, Mr. Moul suggests that the Company is exposed to additional risks beyond those inherent in the proxy group. According to Mr. Moul, such risks include regulatory risks and operational risks, among other risks.[98] Mr. Moul also suggests that his cost of equity estimates for UGI reflect the inclusion of a weather normalization adjustment ("WNA").

Q. Do you agree with Mr. Moul that these firm-specific risk factors should influence UGI's cost of equity or awarded ROE?

A. No. All companies face business risks, including the other utilities in the proxy group; business risks are not unique to UGI. As discussed above, it is a well-known concept in finance that firm-specific risks are unrewarded by the market. This is largely because firm-specific risk can be eliminated through portfolio diversification. Scholars widely recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing.[99]

Unlike interest rate risk, inflation risk, and other market risks that affect all companies in the stock market, the risk factors discussed by Mr. Moul are merely business risks specific to UGI. Investors do not require an additional term for these firm-specific

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[98] *See* Direct testimony of Paul R. Moul, pp. 7-13.

[99] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

business risks. Another way to consider this issue is to look at the CAPM and DCF Model. Did the creators of these highly regarded cost of equity models, which have been relied upon for decades by companies and investors to make crucial business decisions, simply neglect to add an input for business risks? Of course not. The DCF Model considers stock price, dividends, and a long-term growth rate. The CAPM considers the risk-free rate, beta, and the equity risk premium. Neither model includes an input for business risks due to the well-known truth that investors do not expect a return for such risks. Therefore, the Company's firm-specific business risks, while perhaps relevant to other issues in the rate case, have no meaningful effect on the cost of equity estimate. Rather, it is market risk that is rewarded by the market, and this concept is thoroughly addressed in my CAPM analysis discussed above. Thus, the Commission should reject any additional premium Mr. Moul has added to an already overstated cost of equity estimate to account for any firm-specific risks. This concept was also discussed and illustrated above in my testimony.[100]

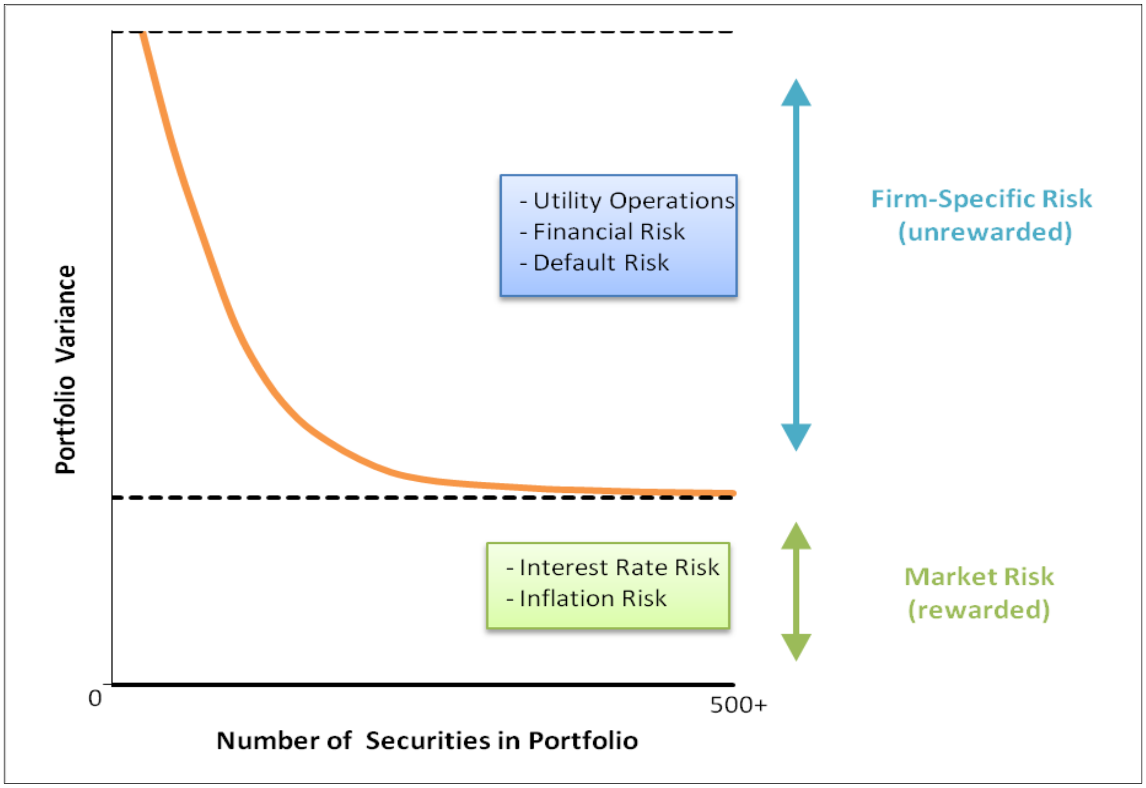
Q. Is UGI's proposed WNA a type of firm-specific business risk that should not directly affect the Company's cost of equity estimate?

A. Yes. OCA witness Jerome Mierzwa makes specific recommendations regarding the WNA in his direct testimony. Regardless of what the Commission decides regarding the WNA, it would not affect the Company's cost of equity estimate, nor should it impact a fair authorized ROE. Regulatory mechanisms relate to firm-specific risks, which are not rewarded by the market, and thus do not materially impact the cost of equity.

These important concepts are again illustrated in the figure below.

[100] *See* Section IV above.

Figure 13:
Effects of Portfolio Diversification



The financial models presented in my testimony (particularly the CAPM) directly measure market risk, which is the type of risk the Commission should focus on when determining a fair authorized ROE.

B. Comparable Earnings

Q. Please summarize Mr. Moul's comparable earnings approach.

A. Mr. Moul also analyzed the returns realized by non-regulated companies as an indication of UGI's cost of equity.[101] The results of his comparable earnings approach indicate a cost of equity for UGI of 12.7%.[102]

Q. Do you agree with Mr. Moul's analyses?

A. No. There are two notable problems with Mr. Moul's comparable earnings approach: (1) earned returns do not indicate the cost of equity; and (2) there is no marginal value in analyzing competitive firms beyond those of the utility proxy group in terms of assessing a comparable risk profile. First, the earned return of any company should have a meaningful effect on its cost of equity. Conceptually, "earned" returns and "expected" returns are different from each other. For example, we might conduct a cost of equity analysis on Walmart's stock and determine that, based on the risk inherent in that investment, we should "expect" a 10% return on our investment (i.e., the cost of equity from Walmart's perspective). Suppose that Walmart, however, has a bad year and only "earned" a 5% ROE. This does not mean that going forward we will now "expect" a return of only 5% on our equity investment in Walmart. Likewise, the same would be true if Walmart had a good year and earned a 20% return. In finance, the "expected" return on equity as investor (which is synonymous with the "cost" of equity from the company's perspective) is simply based on the risk inherent in that investment, and is not directly

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[101] Direct testimony of Paul R. Moul, pp. 46-49.

[102] *Id*. at p. 49, line 22.

influenced by the company's actual, earned return for any given period of time. Thus, Mr. Moul's analysis of earned returns does not add any value for assessing the cost of equity for UGI beyond the results of the CAPM and DCF Model.

The second problem with Mr. Moul's comparable earnings approach is that it uses the earned returns of non-regulated, non-utility companies as an indication of UGI's cost of equity. Despite the title of Mr. Moul's model, competitive, non-utility companies are decisively *incomparable* to UGI. Primarily, the risk profiles of competitive firms will tend to be higher than those of low-risk utilities; thus, their cost of equity estimates will generally be higher. Not surprisingly, the results of Mr. Moul's "comparable" earnings approach are higher than those produced by the models he conducted on the utility proxy group.[103] There is simply no marginal value added to the process of estimating utility cost of equity by using non-utility, non-regulated firms in a proxy group that should contain firms with relatively similar risk profiles to the regulated utility being analyzed. Moreover, the results of Mr. Moul's comparable earnings approach is *more than 500 basis points* above a reasonable estimate for UGI's market-based cost of equity. In addition, Mr. Moul's results are more than 400 basis points above the current "ceiling" for utility cost of equity, which is discussed further below.

[103] Direct Testimony of Paul R. Moul, Exhibit PRM-1, Sch. 1, p. 2.

C. <u>Management Performance Premium</u>

Q. Please describe Mr. Moul's management performance premium.

A. Mr. Moul includes an additional 0.2% to his cost of equity estimate for the "Company's exemplary management."[104]

Q. Do you agree with Mr. Moul's management performance premium?

A. No. Such a premium is completely unrelated to UGI's cost of equity estimate. In financial textbooks, treatises, and other authoritative literature, I have not seen anyone suggest that this type of premium should be added to a cost of equity estimate. It is inappropriate to add an arbitrary and unsupported premium on top of awarded ROE recommendation that is at least 300 basis points higher than UGI's actual cost of equity.

Q. Did the Commission recently reject a management performance premium in the UGI Gas case?

A. Yes. In the last rate case for the UGI Gas division, UGI Gas proposed a 25-basis point premium for management effectiveness.[105] The Commission found that "such an upward adjustment is contrary to the public interest."[106] The Company's management performance claim in this case encompasses activities commenced as early as 2010 or projected to occur well past the end of the FPFTY.[107] Similarly, communications tools implemented by UGI

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[104] Direct Testimony of Paul R. Moul, p. 4, line 14.

[105] *Pa. PUC v. UGI Energy – Gas Div.*, Docket No. R-2020-3018929, Order at 161-168 (June 22, 2021) (UGI Gas Order).

[106] *Id*. at pg. 167.

[107] OCA-XI-3 (Reduction in interruptions in CEMI areas discussed by UGI Witness McDonald direct page 15 based on comparison of 2010-2014 and 2016-2018 measures); OCA-XI-9 (UGI Witness McDonald's direct page 19 discussion of 26,000 poles relates to plans for 2023-2025); OCA-XI-11 (Two of the 6 substation retirements discussed by UGI Witness McDonald direct page 19 will be retired by the end of the FPFTY).

in 2015 and 2018 came several years after introduction by another Exelon affiliate.[108] OCA witness Roger Colton's review of the Company's customer service performance does not support the Company's claim. The Company already has an obligation to provide service that is safe, adequate, reasonable and efficient. I recommend the Commission deny the Company's proposed management performance premium in this case for the same reasons that it was denied in the UGI Gas case.

Q. Have you quantified the financial impact to ratepayers that Mr. Moul's management performance premium would have?

A. Yes. As addressed in the direct testimony of OCA witness Mugrace, an increase of 0.2% to the ROE for Mr. Moul's management performance premium would increase the revenue requirement by $4.9 million.

VIII. COST OF EQUITY SUMMARY

Q. Please summarize the results of the CAPM and DCF Model discussed above.

A. The following figure shows the cost of equity results from each model I employed in this case.[109]

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[108] OCA-XI-12 (ComEd was the first Exelon utility to launch a mobile application in 2012. UGI first deployed in February 2018. ComEd was the first Exelon utility to develop two-way outage text features in 2012. UGI first deployed this in October 2015).

[109] Exhibit DJG-12.

Figure 14:
Cost of Equity Summary

Model	Cost of Equity
Discounted Cash Flow Model	6.7%
Capital Asset Pricing Model	7.2%
Average	**7.0%**

The average cost of equity resulting from my DCF Model and the CAPM is 7.0%.

Q. Please comment on the Commission's preference for DCF results.

A. It is my understanding that in prior cases, the Commission has indicated a preference for the results of the DCF Model to estimate cost of equity, while using the CAPM results as an alternative to verify the reasonableness of the results. As shown above, when reasonable inputs are used in both models (as applied to the proxy group in this case under current market conditions), the results of the models are relatively close. I would also add that unlike the DCF Model, the CAPM was specifically designed to estimate cost of equity, and it has direct inputs designed to assess market risk and the relative impacts of market risks on individual firms. The CAPM also avoids some of the circular reference problems inherent in the DCF Model when it issued to set the authorized ROE in utility rate cases.

IX. <u>CAPITAL STRUCTURE</u>

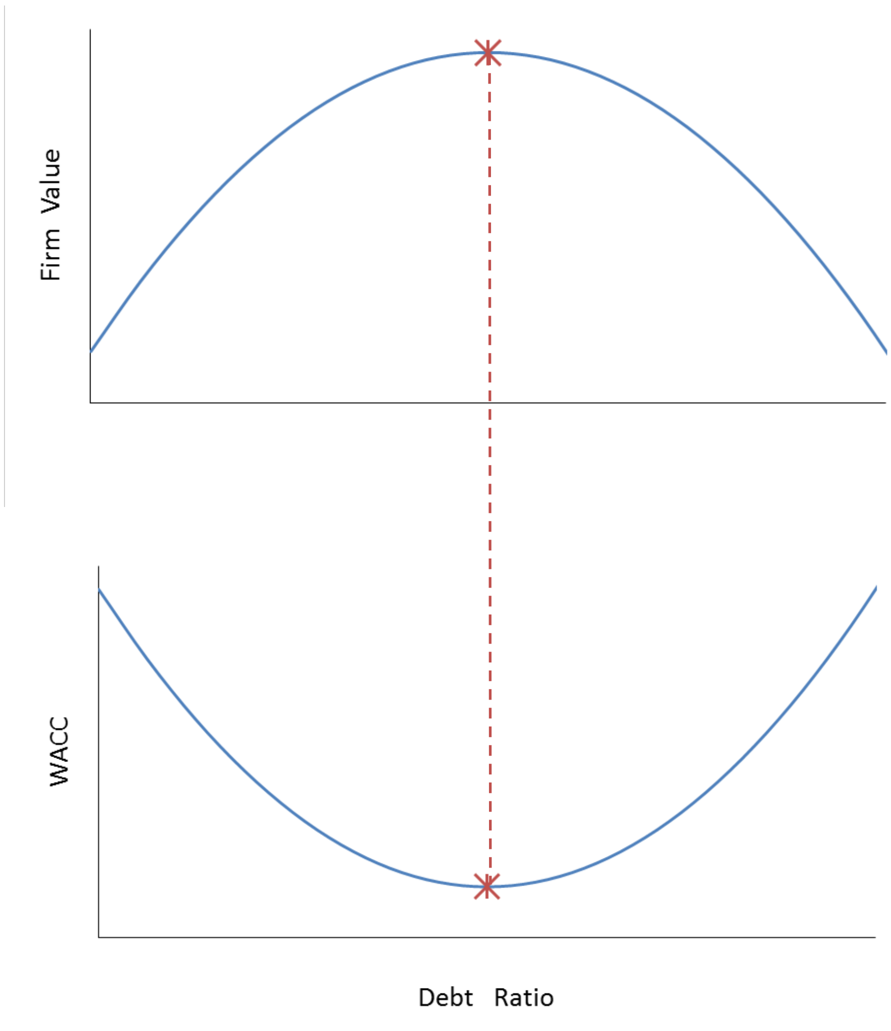
Q. Describe in general the concept of a company's capital structure.

A. "Capital structure" refers to the way a company finances its overall operations through external financing. The primary sources of long-term, external financing are debt capital and equity capital. Debt capital usually comes in the form of contractual bond issues that require the firm to make payments, while equity capital represents an ownership interest in the form of stock. Because a firm cannot pay dividends on common stock until it satisfies its debt obligations to bondholders, stockholders are referred to as "residual claimants." The fact that stockholders have a lower priority to claims on company assets increases their risk and the required return relative to bondholders. Thus, equity capital has a higher cost than debt capital. Firms can reduce their WACC by recapitalizing and increasing their debt financing. In addition, because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation.

Q. Is it true that, by increasing debt, competitive firms can add value and reduce their WACC?

A. Yes, it is. A competitive firm can add value by increasing debt. After a certain point, however, the marginal cost of additional debt outweighs its marginal benefit. This is because the more debt the firm uses, the higher interest expense it must pay, and the likelihood of loss increases. This also increases the risk of non-recovery for both bondholders and shareholders, causing both groups of investors to demand a greater return on their investment. Thus, if debt financing is too high, the firm's WACC will increase instead of decrease. The following figure illustrates these concepts.

Figure 15:
Optimal Debt Ratio



As shown in this figure, a competitive firm’s value is maximized when the WACC is minimized. In both graphs, the debt ratio is shown on the x-axis. By increasing its debt ratio, a competitive firm can minimize its WACC and maximize its value. At a certain point, however, the benefits of increasing debt do not outweigh the costs of the additional risks to both bondholders and shareholders, as each type of investor will demand higher returns for the additional risk they have assumed.[110]

Q. Does the rate base rate of return model effectively incentivize utilities to operate at the optimal capital structure?

A. No. While it is true that competitive firms maximize their value by minimizing their WACC, this is not the case for regulated utilities. Under the rate base rate of return model, a higher WACC results in higher rates, all else held constant. The basic revenue requirement equation is as follows:

Equation 7:
Revenue Requirement for Regulated Utilities

$$RR = O + d + T + \boldsymbol{r}(A - D)$$

where:	RR	=	*revenue requirement*
	O	=	*operating expenses*
	d	=	*depreciation expense*
	T	=	*corporate tax*
	$\boldsymbol{r}$	=	***weighted average cost of capital (WACC)***
	A	=	*plant investments*
	D	=	*accumulated depreciation*

As shown in this equation, utilities can increase their revenue requirement by <u>increasing</u> their WACC, not by minimizing it. Thus, because there is no incentive for a regulated utility to minimize its WACC, a commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC.

[110] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 440-41 (3rd ed., South Western Cengage Learning 2010).

Q. Can utilities generally afford to have higher debt levels than other industries?

A. Yes. Because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios (or "leverage"). As aptly stated by Dr. Damodaran:

> Since financial leverage multiplies the underlying business risk, it stands to reason that firms that have high business risk should be reluctant to take on financial leverage. It also stands to reason that firms that operate in stable businesses should be much more willing to take on financial leverage. Utilities, for instance, have historically had high debt ratios but have not had high betas, mostly because their underlying businesses have been stable and fairly predictable.[111]

Note that the author explicitly contrasts utilities with firms that have high underlying business risk. Because utilities have low levels of risk and operate a stable business, they should generally operate with relatively high levels of debt to achieve their optimal capital structure.

Q. Are the capital structures of the proxy group a source that can be used to assess a prudent capital structure?

A. Yes. However, while the capital structures of the proxy group might provide some indication of an appropriate capital structure for the utility being studied, it is preferable to also consider additional types of analyses. The average debt ratios of a utility proxy group will likely be lower than what would be observed in a pure competitive environment. As I explain above, this is because utilities do not have a financial incentive to operate at the optimal capital structure.

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[111] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 196 (3rd ed., John Wiley & Sons, Inc. 2012).

Q. How can utility regulatory commissions help overcome the fact that utilities do not have a natural financial incentive to minimize their cost of capital?

A. While under the rate base rate of return model utilities do not have a natural financial incentive to minimize their cost of capital, competitive firms, in contrast, can and do maximize their value by minimizing their cost of capital. Competitive firms minimize their cost of capital by including a sufficient amount of debt in their capital structures. They do not do this because it is required by a regulatory body, but rather because their shareholders demand it in order to maximize value. The Commission can provide this incentive to UGI by acting as a surrogate for competition and setting rates consistent with a capital structure that is similar to what would be appropriate in a competitive, as opposed to a regulated, environment.

Q. Please describe how you assessed the reasonableness of UGI's proposed capital structure in this case.

A. In this case, I examined the capital structures of the proxy group, as well as the capital structure of UGI's parent company, UGI Corp. Finally, I also looked at capital structures observed in other competitive industries to assess the overall reasonableness of my recommendation.

Q. Please describe the debt ratios of the proxy group.

A. Again, Mr. Moul and I used the same proxy group of utilities for our cost of capital analyses. The proxy group of utilities reported an average debt ratio of 53%, which is considerably higher than UGI's proposed debt ratio.[112]

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[112] Exhibit DJG-14.

Q. What is the capital structure of UGI's parent company, UGI Corp.?

A. At the end of 2021, UGI Corp. reported a debt ratio of 53.4%, which is similar to the average debt ratio of the proxy group, and notably higher than the Company's proposed debt ratio of only 45%.

Q. Did you also look at other competitive firms around the country to compare their debt ratios?

A. Yes. In fact, there are currently nearly 2,000 firms in various industries across the country with debt ratios of 50% or greater, with an average debt ratio of 61 percent.[113] The following figure shows a sample of these industries, with debt ratios of at least 56%.

[113] Exhibit DJG-15.

Figure 16:
Industries with Debt Ratios of 56% or Greater

Industry	# Firms	Debt Ratio
Air Transport	21	85%
Hospitals/Healthcare Facilities	31	80%
Hotel/Gaming	66	77%
Brokerage & Investment Banking	31	76%
Retail (Automotive)	32	72%
Food Wholesalers	15	68%
Retail (Grocery and Food)	15	68%
Rubber& Tires	2	67%
Bank (Money Center)	7	67%
Advertising	49	67%
Computers/Peripherals	46	67%
Auto & Truck	26	66%
Real Estate (Operations & Services)	51	66%
Retail (Special Lines)	76	64%
Cable TV	11	63%
Oil/Gas Distribution	21	63%
Packaging & Container	26	62%
Telecom. Services	42	61%
Recreation	60	61%
Broadcasting	28	60%
Transportation (Railroads)	4	60%
R.E.I.T.	238	60%
Power	50	60%
Telecom (Wireless)	17	59%
Transportation	17	59%
Beverage (Soft)	32	58%
Utility (Water)	14	57%
Retail (Distributors)	68	57%
Office Equipment & Services	18	57%
Aerospace/Defense	73	57%
Household Products	118	56%
Computer Services	83	56%
Green & Renewable Energy	20	56%
Total / Average	**1,408**	**64%**

Many of the industries shown here, like public utilities, are generally well-established industries with large amounts of capital assets. The shareholders of these industries demand higher debt ratios in order to maximize their profits. There are several notable industries that are relatively comparable to public utilities in some respects. These debt ratios, as well as the average debt ratio of the utility proxy group, are notably higher than UGI's proposed debt ratio of only 44.88%.

Q. What is your recommendation regarding the Company's capital structure?

A. The analysis strongly indicates that UGI's proposed debt ratio is too low to be considered fair for ratemaking. An insufficiently low debt ratio causes the weighted average cost of capital to be unreasonably high. The table below compares the various debt ratios discussed in my testimony, and it highlights the unreasonableness of UGI's proposed debt ratio.

Figure 17:
Debt Ratio Comparison

Source	Debt Ratio
Power	60%
Telecom (Wireless)	59%
Utility (Water)	57%
Green & Renewable Energy	56%
Proxy Group of Utilities	**53%**
UGI Corp.	**53%**
Garrett Proposal	**50%**
Company Proposal	**45%**

Based on my findings, I recommend the Commission impute a capital structure for ratemaking purposes consisting of 50% debt and 50% equity. Although my findings indicate UGI's debt ratio should arguably be higher than 50%, I am recommending a 50% debt ratio in the interest of reasonableness and gradualism.

Q. If the Commission were to adopt UGI's proposed debt ratio, would that decision further reduce UGI's low-risk profile?

A. Yes. As illustrated in the optimal capital structure table above, increasing the debt ratio to an optimal level effectively minimizes the weighted average cost of capital. However, if UGI's authorized ROE is higher than its cost of equity, it will increase the WACC beyond its lowest optimal level. Thus, if the Commission were to approve UGI's low debt ratio, it should also strongly consider a meaningful reduction in its authorized ROE.

Q. Does this conclude your testimony?

A. Yes. To the extent I have not addressed an issue or proposal raised by the Company in this proceeding, it should not be construed that I agree with the same.

APPENDIX A:

DISCOUNTED CASH FLOW MODEL THEORY

The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. In its most general form, the DCF Model is expressed as follows:[114]

Equation 8:
General Discounted Cash Flow Model

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n}{(1+k)^n}$$

where:	P_0	=	*current stock price*
	$D_1 \ldots D_n$	=	*expected future dividends*
	k	=	*discount rate / required return*

The General DCF Model would require an estimation of an infinite stream of dividends. Because this would be impractical, analysts use more feasible variations of the General DCF Model, which are discussed further below.

The DCF Models rely on the following four assumptions:[115]

1. Investors evaluate common stocks in the classical valuation framework; that is, they trade securities rationally at prices reflecting their perceptions of value;

2. Investors discount the expected cash flows at the same rate (K) in every future period;

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[114] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 410 (9th ed., McGraw-Hill/Irwin 2013).

[115] *See* Roger A. Morin, *New Regulatory Finance* 252 (Public Utilities Reports, Inc. 2006) (1994).

3. The K obtained from the DCF equation corresponds to that specific stream of future cash flows alone; and

4. Dividends, rather than earnings, constitute the source of value.

The General DCF can be rearranged to make it more practical for estimating the cost of equity. Regulators typically rely on some variation of the Constant Growth DCF Model, which is expressed as follows:

Equation 9:
Constant Growth Discounted Cash Flow Model

$$K = \frac{D_1}{P_0} + g$$

where:	K	=	*discount rate / required return on equity*
	D_1	=	*expected dividend per share one year from now*
	P_0	=	*current stock price*
	g	=	*expected growth rate of future dividends*

Unlike the General DCF Model, the Constant Growth DCF Model solves for the required return (*K*) directly. In addition, by assuming that dividends grow at a constant rate, the dividend stream from the General DCF Model may be substituted with a term representing the expected constant growth rate of future dividends (*g*). The Constant Growth DCF Model may be considered in two parts. The first part is the dividend yield (D_1/P_0), and the second part is the growth rate (*g*). In other words, the required return in the DCF Model is equivalent to the dividend yield plus the growth rate.

In addition to the four assumptions listed above, the Constant Growth DCF Model relies on the following four additional assumptions:[116]

[116] *See* Roger A. Morin, *New Regulatory Finance* 254–56 (Public Utilities Reports, Inc. 2006) (1994).

1. The discount rate (K) must exceed the growth rate (g);

2. The dividend growth rate (g) is constant in every year to infinity;

3. Investors require the same return (K) in every year; and

4. There is no external financing; that is, growth is provided only by the retention of earnings.

Because the growth rate in this model is assumed to be constant, it is important not to use growth rates that are unreasonably high. In fact, the constant growth rate estimate for a regulated utility with a defined service territory should not exceed the growth rate for the economy in which it operates.

The basic form of the Constant Growth DCF Model described above is sometimes referred to as the "Annual" DCF Model. This is because the model assumes an annual dividend payment to be paid at the end of every year, as well as an increase in dividends once each year. In reality, however, most utilities pay dividends on a quarterly basis. The Constant Growth DCF equation may be modified to reflect the assumption that investors receive successive quarterly dividends and reinvest them throughout the year at the discount rate. This variation is called the Quarterly Approximation DCF Model.[117]

Equation 10:
Quarterly Approximation Discounted Cash Flow Model

$$K = \left[\frac{d_0(1+g)^{1/4}}{P_0} + (1+g)^{1/4}\right]^4 - 1$$

where: K = *discount rate / required return*
d_0 = *current quarterly dividend per share*
P_0 = *stock price*
g = *expected growth rate of future dividends*

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[117] *See* Roger A. Morin, *New Regulatory Finance* 348 (Public Utilities Reports, Inc. 2006) (1994).

The Quarterly Approximation DCF Model assumes that dividends are paid quarterly, and that each dividend is constant for four consecutive quarters. All else held constant, this model results in the highest cost of equity estimate for the utility in comparison to other DCF Models because it accounts for the quarterly compounding of dividends. There are several other variations of the Constant Growth (or Annual) DCF Model, including a Semi-Annual DCF Model, which is used by the Federal Energy Regulatory Commission ("FERC"). These models, along with the Quarterly Approximation DCF Model, have been accepted in regulatory proceedings as useful tools for estimating the cost of equity.

APPENDIX B:

CAPITAL ASSET PRICING MODEL THEORY

The Capital Asset Pricing Model ("CAPM") is a market-based model founded on the principle that investors demand higher returns for incurring additional risk.[118] The CAPM estimates this required return. The CAPM relies on the following assumptions:

1. Investors are rational, risk-adverse, and strive to maximize profit and terminal wealth;

2. Investors make choices based on risk and return. Return is measured by the mean returns expected from a portfolio of assets; risk is measured by the variance of these portfolio returns;

3. Investors have homogenous expectations of risk and return;

4. Investors have identical time horizons;

5. Information is freely and simultaneously available to investors;

6. There is a risk-free asset, and investors can borrow and lend unlimited amounts at the risk-free rate;

7. There are no taxes, transaction costs, restrictions on selling short, or other market imperfections; and

8. Total asset quality is fixed, and all assets are marketable and divisible.[119]

While some of these assumptions may appear to be restrictive, they do not outweigh the inherent value of the model. The CAPM has been widely used by firms, analysts, and regulators for decades to estimate the cost of equity capital.

The basic CAPM equation is expressed as follows:

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[118] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963).

[119] *Id*.

Equation 11:
Capital Asset Pricing Model

$$K = R_F + \beta_i(R_M - R_F)$$

where:	K	=	*required return*
	R_F	=	*risk-free rate*
	β	=	*beta coefficient of asset i*
	R_M	=	*required return on the overall market*

There are essentially three terms within the CAPM equation that are required to calculate the required return (K): (1) the risk-free rate (R_F); (2) the beta coefficient (β); and (3) the equity risk premium ($R_M - R_F$), which is the required return on the overall market less the risk-free rate.

Raw Beta Calculations and Adjustments.

A stock's beta equals the covariance of the asset's returns with the returns on a market portfolio, divided by the portfolio's variance, as expressed in the following formula:[120]

Equation 12:
Beta

$$\beta_i = \frac{\sigma_{im}}{\sigma_m^2}$$

where:	β_i	=	*beta of asset i*
	σ_{im}	=	*covariance of asset i returns with market portfolio returns*
	$\sigma^2{}_m$	=	*variance of market portfolio*

Betas that are published by various research firms are typically calculated through a regression analysis that considers the movements in price of an individual stock and movements in the price of the overall market portfolio. The betas produced by this regression analysis are considered "raw" betas. There is empirical evidence that raw betas should be adjusted to account

[120] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180–81 (3rd ed., South Western Cengage Learning 2010).

for beta's natural tendency to revert to an underlying mean.[121] Some analysts use an adjustment method proposed by Blume, which adjusts raw betas toward the market mean of one.[122] While the Blume adjustment method is popular due to its simplicity, it is arguably arbitrary, and some would say not useful at all. According to Dr. Damodaran: "While we agree with the notion that betas move toward 1.0 over time, the [Blume adjustment] strikes us as arbitrary and not particularly useful."[123] The Blume adjustment method is especially arbitrary when applied to industries with consistently low betas, such as the utility industry. For industries with consistently low betas, it is better to employ an adjustment method that adjusts raw betas toward an industry average, rather than the market average. Vasicek proposed such a method, which is preferable to the Blume adjustment method because it allows raw betas to be adjusted toward an industry average, and also accounts for the statistical accuracy of the raw beta calculation.[124] In other words, "[t]he Vasicek adjustment seeks to overcome one weakness of the Blume model by not applying the same adjustment to every security; rather, a security-specific adjustment is made depending on the statistical quality of the regression."[125] The Vasicek beta adjustment equation is expressed as follows:

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[121] *See* Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 84–92 (Financial Management Autumn 1990).

[122] See Marshall Blume, *On the Assessment of Risk*, Vol. 26, No. 1 The Journal of Finance 1 (1971).

[123] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 187 (3rd ed., John Wiley & Sons, Inc. 2012).

[124] Oldrich A. Vasicek, *A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas* 1233–1239 (Journal of Finance, Vol. 28, No. 5, December 1973).

[125] 2012 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook 77–78 (Morningstar 2012).

Equation 13:
Vasicek Beta Adjustment

$$\beta_{i1} = \frac{\sigma^2_{\beta_{i0}}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_0 + \frac{\sigma^2_{\beta 0}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_{i0}$$

where:	β_{i1}	=	*Vasicek adjusted beta for security i*
	β_{i0}	=	*historical beta for security i*
	β_0	=	*beta of industry or proxy group*
	$\sigma^2_{\beta 0}$	=	*variance of betas in the industry or proxy group*
	$\sigma^2_{\beta i0}$	=	*square of standard error of the historical beta for security i*

The Vasicek beta adjustment is an improvement on the Blume model because the Vasicek model does not apply the same adjustment to every security. A higher standard error produced by the regression analysis indicates a lower statistical significance of the beta estimate. Thus, a beta with a high standard error should receive a greater adjustment than a beta with a low standard error. As stated in Ibbotson:

> While the Vasicek formula looks intimidating, it is really quite simple. The adjusted beta for a company is a weighted average of the company's historical beta and the beta of the market, industry, or peer group. How much weight is given to the company and historical beta depends on the statistical significance of the company beta statistic. If a company beta has a low standard error, then it will have a higher weighting in the Vasicek formula. If a company beta has a high standard error, then it will have lower weighting in the Vasicek formula. An advantage of this adjustment methodology is that it does not force an adjustment to the market as a whole. Instead, the adjustment can be toward an industry or some other peer group. <u>This is most useful in looking at companies in industries that on average have high or low betas</u>.[126]

Thus, the Vasicek adjustment method is statistically more accurate and is the preferred method to use when analyzing companies in an industry that has inherently low betas, such as the utility industry. The Vasicek method was also confirmed by Gombola, who conducted a study

[126] 2012 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook 78 (Morningstar 2012).

specifically related to utility companies. Gombola concluded that "[t]he strong evidence of auto-regressive tendencies in utility betas lends support to the application of adjustment procedures such as the . . . adjustment procedure presented by Vasicek."[127] Gombola also concluded that adjusting raw betas toward the market mean of 1.0 is too high, and that "[i]nstead, they should be adjusted toward a value that is less than one."[128] In conducting the Vasicek adjustment on betas in previous cases, it reveals that utility betas are even lower than those published by Value Line.[129] Gombola's findings are particular important here, because his study was conducted specifically on utility companies. This evidence indicates that using Value Line's betas in a CAPM cost of equity estimate for a utility company may lead to overestimated results. Regardless, adjusting betas to a level that is higher than Value Line's betas is not reasonable, and it would produce CAPM cost of equity results that are too high.

[127] Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 92 (Financial Management Autumn 1990) (emphasis added).

[128] Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 91–92 (Financial Management Autumn 1990) (emphasis added).

[129] *See e.g.* Responsive Testimony of David J. Garrett, filed March 21, 2016 in Cause No. PUD 201500273 before the Corporation Commission of Oklahoma (OG&E's 2015 rate case), at pp. 56–59.

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EDUCATION

University of Oklahoma — Norman, OK
Master of Business Administration — 2014
Areas of Concentration: Finance, Energy

University of Oklahoma College of Law — Norman, OK
Juris Doctor — 2007
Member, American Indian Law Review

University of Oklahoma — Norman, OK
Bachelor of Business Administration — 2003
Major: Finance

PROFESSIONAL DESIGNATIONS

Society of Depreciation Professionals
Certified Depreciation Professional (CDP)

Society of Utility and Regulatory Financial Analysts
Certified Rate of Return Analyst (CRRA)

The Mediation Institute
Certified Civil / Commercial & Employment Mediator

WORK EXPERIENCE

Resolve Utility Consulting PLLC — Oklahoma City, OK
Managing Member — 2016 – Present
Provide expert analysis and testimony specializing in depreciation and cost of capital issues for clients in utility regulatory proceedings.

Oklahoma Corporation Commission — Oklahoma City, OK
Public Utility Regulatory Analyst — 2012 – 2016
Assistant General Counsel — 2011 – 2012
Represented commission staff in utility regulatory proceedings and provided legal opinions to commissioners. Provided expert analysis and testimony in depreciation, cost of capital, incentive compensation, payroll and other issues.

Perebus Counsel, PLLC — Oklahoma City, OK
Managing Member — 2009 – 2011
Represented clients in the areas of family law, estate planning, debt negotiations, business organization, and utility regulation.

Moricoli & Schovanec, P.C. — Oklahoma City, OK
Associate Attorney — 2007 – 2009
Represented clients in the areas of contracts, oil and gas, business structures and estate administration.

TEACHING EXPERIENCE

University of Oklahoma — Norman, OK
Adjunct Instructor – "Conflict Resolution" — 2014 – 2021
Adjunct Instructor – "Ethics in Leadership"

Rose State College — Midwest City, OK
Adjunct Instructor – "Legal Research" — 2013 – 2015
Adjunct Instructor – "Oil & Gas Law"

PUBLICATIONS

American Indian Law Review — Norman, OK
"Vine of the Dead: Reviving Equal Protection Rites for Religious Drug Use" — 2006
(31 Am. Indian L. Rev. 143)

PROFESSIONAL ASSOCIATIONS

Oklahoma Bar Association — 2007 – Present

Society of Depreciation Professionals — 2014 – Present
Board Member – President — 2017
Participate in management of operations, attend meetings, review performance, organize presentation agenda.

Society of Utility Regulatory Financial Analysts — 2014 – Present

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater / East Whiteland Township	A-2021-3026132	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
Public Service Commission of South Carolina	Kiawah Island Utility, Inc.	2021-324-WS	Cost of capital, awarded rate of return, capital structure	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater / Willistown Township	A-2021-3027268	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45621	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Arkansas Public Service Commission	Southwestern Electric Power Company	21-070-U	Cost of capital, depreciation rates, net salvage	Western Arkansas Large Energy Consumers
Federal Energy Regulatory Commission	Southern Star Central Gas Pipeline	RP21-778-002	Depreciation rates, service lives, net salvage	Consumer-Owned Shippers
Railroad Commission of Texas	Participating Texas gas utilities in consolidated proceeding	OS-21-00007061	Securitization of extraordinary gas costs arising from winter storms	The City of El Paso
Public Service Commission of South Carolina	Palmetto Wastewater Reclamation, Inc.	2021-153-S	Cost of capital, awarded rate of return, capital structure, ring-fencing	South Carolina Office of Regulatory Staff
Public Utilties Commission of the State of Colorado	Public Service Company of Colorado	21AL-0317E	Cost of capital, depreciation rates, net salvage	Colorado Energy Consumers
Pennsylvania Public Utility Commission	City of Lancaster - Water Department	R-2021-3026682	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 51802	Depreciation rates, service lives, net salvage	The Alliance of Xcel Municipalities
Pennsylvania Public Utility Commission	The Borough of Hanover - Hanover Municipal Waterworks	R-2021-3026116	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Delmarva Power & Light Company	9670	Cost of capital and authorized rate of return	Maryland Office of People's Counsel
Oklahoma Corporation Commission	Oklahoma Natural Gas Company	PUD 202100063	Cost of capital, awarded rate of return, capital structure	Oklahoma Industrial Energy Consumers
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45576	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	El Paso Electric Company	PUC 52195	Depreciation rates, service lives, net salvage	The City of El Paso

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Pennsylvania Public Utility Commission	Aqua Pennsylvania	R-2021-3027385	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Public Service Company of New Mexico, Avangrid, NM Green Holdings, PNM Resources	20-00222-UT	Ring fencing, capital structure	Albuquerque Bernalillo County Water Utility Authority
Public Service Commission of the State of Montana	NorthWestern Energy	D2021.02.022	Cost of capital, awarded rate of return, capital structure	Montana Consumer Counsel
Pennsylvania Public Utility Commission	PECO Energy Company	R-2021-3024601	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Southwestern Public Service Company	20-00238-UT	Cost of capital and authorized rate of return	The New Mexico Large Customer Group; Occidental Permian
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 202100055	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Pennsylvania Public Utility Commission	Duquesne Light Company	R-2021-3024750	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Columbia Gas of Maryland	9664	Cost of capital and authorized rate of return	Maryland Office of People's Counsel
Indiana Utility Regulatory Commission	Southern Indiana Gas Company, d/b/a Vectren Energy Delivery of Indiana, Inc.	45447	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Southwestern Electric Power Company	PUC 51415	Depreciation rates, service lives, net salvage	Cities Advocating Reasonable Deregulation
New Mexico Public Regulatory Commission	Avangrid, Inc., Avangrid Networks, Inc., NM Green Holdings, Inc., PNM, and PNM Resources	20-00222-UT	Ring fencing and capital structure	The Albuquerque Bernalillo County Water Utility Authority
Indiana Utility Regulatory Commission	Indiana Gas Company, d/b/a Vectren Energy Delivery of Indiana, Inc.	45468	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of Nevada	Nevada Power Company and Sierra Pacific Power Company, d/b/a NV Energy	20-07023	Construction work in progress	MGM Resorts International, Caesars Enterprise Services, LLC, and the Southern Nevada Water Authority
Massachusetts Department of Public Utilities	Boston Gas Company, d/b/a National Grid	D.P.U. 20-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Public Service Commission of the State of Montana	ABACO Energy Services, LLC	D2020.07.082	Cost of capital and authorized rate of return	Montana Consumer Counsel
Maryland Public Service Commission	Washington Gas Light Company	9651	Cost of capital and authorized rate of return	Maryland Office of People's Counsel

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Florida Public Service Commission	Utilities, Inc. of Florida	20200139-WS	Cost of capital and authorized rate of return	Florida Office of Public Counsel
New Mexico Public Regulatory Commission	El Paso Electric Company	20-00104-UT	Cost of capital, depreciation rates, net salvage	City of Las Cruces and Doña Ana County
Public Utilities Commission of Nevada	Nevada Power Company	20-06003	Cost of capital, awarded rate of return, capital structure, earnings sharing	MGM Resorts International, Caesars Enterprise Services, LLC, Wynn Las Vegas, LLC, Smart Energy Alliance, and Circus Circus Las Vegas, LLC
Wyoming Public Service Commission	Rocky Mountain Power	20000-578-ER-20	Cost of capital and authorized rate of return	Wyoming Industrial Energy Consumers
Florida Public Service Commission	Peoples Gas System	20200051-GU 20200166-GU	Cost of capital, depreciation rates, net salvage	Florida Office of Public Counsel
Wyoming Public Service Commission	Rocky Mountain Power	20000-539-EA-18	Depreciation rates, service lives, net salvage	Wyoming Industrial Energy Consumers
Public Service Commission of South Carolina	Dominion Energy South Carolina	2020-125-E	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	The City of Bethlehem	2020-3020256	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Railroad Commission of Texas	Texas Gas Services Company	GUD 10928	Depreciation rates, service lives, net salvage	Gulf Coast Service Area Steering Committee
Public Utilities Commission of the State of California	Southern California Edison	A.19-08-013	Depreciation rates, service lives, net salvage	The Utility Reform Network
Massachusetts Department of Public Utilities	NSTAR Gas Company	D.P.U. 19-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Georgia Public Service Commission	Liberty Utilities (Peach State Natural Gas)	42959	Depreciation rates, service lives, net salvage	Public Interest Advocacy Staff
Florida Public Service Commission	Florida Public Utilities Company	20190155-EI 20190156-EI 20190174-EI	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Illinois Commerce Commission	Commonwealth Edison Company	20-0393	Depreciation rates, service lives, net salvage	The Office of the Illinois Attorney General
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 49831	Depreciation rates, service lives, net salvage	Alliance of Xcel Municipalities
Public Service Commission of South Carolina	Blue Granite Water Company	2019-290-WS	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Railroad Commission of Texas	CenterPoint Energy Resources	GUD 10920	Depreciation rates and grouping procedure	Alliance of CenterPoint Municipalities
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater / East Norriton Township	A-2019-3009052	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Southwestern Public Service Company	19-00170-UT	Cost of capital and authorized rate of return	The New Mexico Large Customer Group; Occidental Permian
Indiana Utility Regulatory Commission	Duke Energy Indiana	45253	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Maryland Public Service Commission	Columbia Gas of Maryland	9609	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-190334	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45235	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of the State of California	Pacific Gas & Electric Company	18-12-009	Depreciation rates, service lives, net salvage	The Utility Reform Network
Oklahoma Corporation Commission	The Empire District Electric Company	PUD 201800133	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Arkansas Public Service Commission	Southwestern Electric Power Company	19-008-U	Cost of capital, depreciation rates, net salvage	Western Arkansas Large Energy Consumers
Public Utility Commission of Texas	CenterPoint Energy Houston Electric	PUC 49421	Depreciation rates, service lives, net salvage	Texas Coast Utilities Coalition
Massachusetts Department of Public Utilities	Massachusetts Electric Company and Nantucket Electric Company	D.P.U. 18-150	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201800140	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2018.9.60	Depreciation rates, service lives, net salvage	Montana Consumer Counsel and Denbury Onshore
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45159	Depreciation rates, grouping procedure, demolition costs	Indiana Office of Utility Consumer Counselor
Public Service Commission of the State of Montana	NorthWestern Energy	D2018.2.12	Depreciation rates, service lives, net salvage	Montana Consumer Counsel

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 201800097	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Wal-Mart
Nevada Public Utilities Commission	Southwest Gas Corporation	18-05031	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	Texas-New Mexico Power Company	PUC 48401	Depreciation rates, service lives, net salvage	Alliance of Texas-New Mexico Power Municipalities
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201700496	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Maryland Public Service Commission	Washington Gas Light Company	9481	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Indiana Utility Regulatory Commission	Citizens Energy Group	45039	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Entergy Texas, Inc.	PUC 48371	Depreciation rates, decommissioning costs	Texas Municipal Group
Washington Utilities & Transportation Commission	Avista Corporation	UE-180167	Depreciation rates, service lives, net salvage	Washington Office of Attorney General
New Mexico Public Regulation Commission	Southwestern Public Service Company	17-00255-UT	Cost of capital and authorized rate of return	HollyFrontier Navajo Refining; Occidental Permian
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 47527	Depreciation rates, plant service lives	Alliance of Xcel Municipalities
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2017.9.79	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Florida Public Service Commission	Florida City Gas	20170179-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-170485	Cost of capital and authorized rate of return	Washington Office of Attorney General
Wyoming Public Service Commission	Powder River Energy Corporation	10014-182-CA-17	Credit analysis, cost of capital	Private customer
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201700151	Depreciation, terminal salvage, risk analysis	Oklahoma Industrial Energy Consumers
Public Utility Commission of Texas	Oncor Electric Delivery Company	PUC 46957	Depreciation rates, simulated analysis	Alliance of Oncor Cities

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Nevada Public Utilities Commission	Nevada Power Company	17-06004	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	El Paso Electric Company	PUC 46831	Depreciation rates, interim retirements	City of El Paso
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-24	Accelerated depreciation of North Valmy plant	Micron Technology, Inc.
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-23	Depreciation rates, service lives, net salvage	Micron Technology, Inc.
Public Utility Commission of Texas	Southwestern Electric Power Company	PUC 46449	Depreciation rates, decommissioning costs	Cities Advocating Reasonable Deregulation
Massachusetts Department of Public Utilities	Eversource Energy	D.P.U. 17-05	Cost of capital, capital structure, and rate of return	Sunrun Inc.; Energy Freedom Coalition of America
Railroad Commission of Texas	Atmos Pipeline - Texas	GUD 10580	Depreciation rates, grouping procedure	City of Dallas
Public Utility Commission of Texas	Sharyland Utility Company	PUC 45414	Depreciation rates, simulated analysis	City of Mission
Oklahoma Corporation Commission	Empire District Electric Company	PUD 201600468	Cost of capital, depreciation rates	Oklahoma Industrial Energy Consumers
Railroad Commission of Texas	CenterPoint Energy Texas Gas	GUD 10567	Depreciation rates, simulated plant analysis	Texas Coast Utilities Coalition
Arkansas Public Service Commission	Oklahoma Gas & Electric Company	160-159-GU	Cost of capital, depreciation rates, terminal salvage	Arkansas River Valley Energy Consumers; Wal-Mart
Florida Public Service Commission	Peoples Gas	160-159-GU	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Arizona Corporation Commission	Arizona Public Service Company	E-01345A-16-0036	Cost of capital, depreciation rates, terminal salvage	Energy Freedom Coalition of America
Nevada Public Utilities Commission	Sierra Pacific Power Company	16-06008	Depreciation rates, net salvage, theoretical reserve	Northern Nevada Utility Customers
Oklahoma Corporation Commission	Oklahoma Gas & Electric Co.	PUD 201500273	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201500208	Cost of capital, depreciation rates, terminal salvage	Public Utility Division

Utility Regulatory Proceedings

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Oklahoma Corporation Commission	Oklahoma Natural Gas Company	PUD 201500213	Cost of capital, depreciation rates, net salvage	Public Utility Division

Proxy Group Summary

Company	Ticker	Market Cap. ($ millions)	Market Category	Value Line Safety Rank	Financial Strength
Atmos Energy Corp	ATO	14,400	Large Cap	1	A+
Chesapeake Utilities Corp	CPK	2,300	Mid Cap	2	A
New Jersey Resources Corporation	NJR	3,900	Mid Cap	2	A+
NiSource Inc	NI	11,200	Large Cap	3	B+
Northwest Natural Holding Company	NWN	1,400	Small Cap	3	A
ONE Gas Inc	OGS	4,000	Mid Cap	2	B++
South Jersey Industries Inc	SJI	2,800	Mid Cap	3	B++
Southwest Gas Holdings Inc	SWX	4,000	Mid Cap	3	A
Spire Inc.	SR	3,300	Mid Cap	2	B++

Value Line Investment Survey

DCF Stock and Index Prices

Exhibit DJG-3

Ticker	^GSPC	ATO	CPK	NJR	NI	NWN	OGS	SJI	SWX	SR
30-day Average	4398	114.42	135.72	44.22	30.18	53.08	85.07	33.82	75.10	68.33
Standard Deviation	139.9	4.13	3.75	1.59	1.05	2.41	3.28	2.06	4.14	2.58
02/23/22	4226	105.39	129.55	39.83	28.21	46.60	75.45	23.27	65.36	62.22
02/24/22	4289	104.75	127.04	41.10	28.33	46.97	77.61	32.55	67.34	63.91
02/25/22	4385	109.09	131.57	43.13	28.98	49.70	81.21	32.81	69.00	65.51
02/28/22	4374	109.81	132.50	43.26	28.93	52.01	83.09	33.63	70.94	66.44
03/01/22	4306	109.93	131.53	42.25	28.65	52.22	82.35	33.70	69.59	65.35
03/02/22	4387	111.14	134.63	43.17	29.19	53.89	84.14	33.97	72.59	66.46
03/03/22	4363	113.74	136.03	44.39	29.67	54.88	85.78	34.24	71.78	68.29
03/04/22	4329	116.15	139.71	44.87	30.48	55.98	87.36	34.29	73.63	70.08
03/07/22	4201	116.01	141.41	45.06	30.11	55.81	88.87	34.52	74.30	70.84
03/08/22	4171	113.40	138.23	45.17	29.61	56.27	88.47	34.45	72.40	69.51
03/09/22	4278	112.18	137.85	43.64	29.65	55.39	83.84	34.74	70.75	67.91
03/10/22	4260	113.29	140.52	44.25	29.92	56.40	86.07	34.83	72.31	68.23
03/11/22	4204	113.74	140.03	43.66	29.79	55.00	86.15	34.55	72.59	68.63
03/14/22	4173	112.86	137.51	43.18	29.61	54.56	85.83	34.28	77.41	67.93
03/15/22	4262	114.11	137.50	43.43	29.85	53.10	85.10	34.32	76.96	67.79
03/16/22	4358	114.35	135.32	43.57	30.09	53.18	83.45	34.58	77.94	67.09
03/17/22	4412	114.47	135.86	43.49	30.14	52.75	83.87	34.40	76.51	67.36
03/18/22	4463	112.73	131.24	43.46	30.09	52.68	82.50	34.01	78.61	66.35
03/21/22	4461	115.24	134.60	44.27	30.36	53.34	84.48	33.97	78.15	67.67
03/22/22	4512	114.16	132.61	44.18	30.22	52.64	83.56	33.94	76.21	67.27
03/23/22	4456	114.31	131.24	43.79	30.25	52.66	83.27	33.91	76.42	66.88
03/24/22	4520	115.67	132.10	44.26	30.54	53.14	84.20	34.01	78.06	67.13
03/25/22	4543	118.52	134.52	45.52	31.14	55.05	86.84	34.14	79.09	69.20
03/28/22	4576	117.79	134.14	45.89	31.05	54.59	87.20	34.13	79.31	69.47
03/29/22	4632	119.18	138.49	46.38	31.43	55.48	87.71	34.45	78.50	70.98
03/30/22	4602	120.37	138.24	46.36	31.61	51.34	88.50	34.41	79.01	71.76
03/31/22	4530	119.49	137.76	45.86	31.80	51.72	88.24	34.55	78.29	71.76
04/01/22	4546	121.41	140.57	47.17	32.08	51.91	89.53	34.85	80.04	72.63
04/04/22	4583	119.18	140.21	46.08	31.72	51.73	88.38	34.76	80.73	72.14
04/05/22	4525	120.23	138.99	45.88	31.86	51.29	89.11	34.46	79.24	73.20

All prices are adjusted closing prices reported by Yahoo! Finance, http://finance.yahoo.com

DCF Dividend Yields

Exhibit DJG-4

Company	Ticker	[1] Dividend	[2] Stock Price	[3] Dividend Yield
Atmos Energy Corp	ATO	0.680	114.42	0.59%
Chesapeake Utilities Corp	CPK	0.480	135.72	0.35%
New Jersey Resources Corporation	NJR	0.363	44.22	0.82%
NiSource Inc	NI	0.235	30.18	0.78%
Northwest Natural Holding Company	NWN	0.482	53.08	0.91%
ONE Gas Inc	OGS	0.620	85.07	0.73%
South Jersey Industries Inc	SJI	0.310	33.82	0.92%
Southwest Gas Holdings Inc	SWX	0.620	75.10	0.83%
Spire Inc.	SR	0.685	68.33	1.00%
Average		**$0.50**	**$71.10**	**0.77%**

[1] 2022 Q1 reported quarterly dividends per share. Nasdaq.com
[2] Average stock price from Exhibit DJG-3
[3] = [1] / [2] (quarterly dividend yield)

DCF Terminal Growth Rate Determinants

Terminal Growth Determinants	Rate	
Nominal GDP	3.8%	[1]
Real GDP	1.8%	[2]
Inflation	2.0%	[3]
Risk Free Rate	2.4%	[4]
Highest	**3.8%**	

[1],[2] [3] CBO, The 2021 Long-Term Budget Outlook, p. 34

[4] I/B/E/S growth rate from Exhibit PRM-1, Sch. 9

[5] From Exhibit DJG-7

DCF Final Results

[1]	[2]	[3]	[4]
Dividend (d_0)	Stock Price (P_0)	Growth Rate (g)	**DCF Result**
$0.50	$71.10	3.80%	**6.7%**

[1] Average proxy dividend from Exhibit DJG-4

[2] Average proxy stock price from Exhibit DJG-3

[3] Highest growth determinant from Exhibit DJG-5

[4] Quarterly DCF Approximation = $[d_0(1 + g)^{0.25}/P_0 + (1 + g)^{0.25}]^4 - 1$

CAPM Risk-Free Rate

Date	Rate
02/23/22	2.29%
02/24/22	2.28%
02/25/22	2.29%
02/28/22	2.17%
03/01/22	2.11%
03/02/22	2.24%
03/03/22	2.24%
03/04/22	2.16%
03/07/22	2.19%
03/08/22	2.24%
03/09/22	2.29%
03/10/22	2.38%
03/11/22	2.36%
03/14/22	2.47%
03/15/22	2.49%
03/16/22	2.46%
03/17/22	2.50%
03/18/22	2.42%
03/21/22	2.55%
03/22/22	2.60%
03/23/22	2.52%
03/24/22	2.51%
03/25/22	2.60%
03/28/22	2.57%
03/29/22	2.53%
03/30/22	2.48%
03/31/22	2.44%
04/01/22	2.44%
04/04/22	2.48%
04/05/22	2.57%
Average	**2.40%**

*Daily Treasury Yield Curve Rates on 30-year T-bonds, http://www.treasury.gov/resources-center/data-chart-center/interest-rates/

CAPM Beta Coefficient

Company	Ticker	Beta
Atmos Energy Corp	ATO	0.80
Chesapeake Utilities Corp	CPK	0.80
New Jersey Resources Corporation	NJR	1.00
NiSource Inc	NI	0.85
Northwest Natural Holding Company	NWN	0.80
ONE Gas Inc	OGS	0.80
South Jersey Industries Inc	SJI	1.00
Southwest Gas Holdings Inc	SWX	0.95
Spire Inc.	SR	0.85
Average		0.87

Betas from Value Line Investment Survey

Exhibit DJG-9

CAPM Implied Equity Risk Premium Estimate

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Year	Market Value	Operating Earnings	Dividends	Buybacks	Earnings Yield	Dividend Yield	Buyback Yield	Gross Cash Yield
2015	17,900	885	382	572	4.95%	2.14%	3.20%	5.33%
2016	19,268	920	397	536	4.77%	2.06%	2.78%	4.85%
2017	22,821	1,066	420	519	4.67%	1.84%	2.28%	4.12%
2018	21,027	1,282	456	806	6.10%	2.17%	3.84%	6.01%
2019	26,760	1,305	485	729	4.88%	1.81%	2.72%	4.54%
2020	31,659	1,019	480	520	3.22%	1.52%	1.64%	3.16%

Cash Yield	4.67%	[9]
Growth Rate	2.85%	[10]
Risk-free Rate	2.40%	[11]
Current Index Value	4,398	[12]

	[13]	[14]	[15]	[16]	[17]
Year	1	2	3	4	5
Expected Dividends	211	217	223	230	236
Expected Terminal Value					4960
Present Value	197	189	181	173	3658
Intrinsic Index Value	4398	[18]			
Required Return on Market	7.3%	[19]			
Implied Equity Risk Premium	**4.9%**	[20]			

[1-4] S&P Quarterly Press Releases, data found at https://us.spindices.com/indices/equity/sp-500, Q4 2018
[1] Market value of S&P 500
[5] = [2] / [1]
[6] = [3] / [1]
[7] = [4] / [1]
[8] = [6] + [7]
[9] = Average of [8]
[10] = Compound annual growth rate of [2] = (end value / beginning value)^ $^{1/4}$-1
[11] Risk-free rate from DJG-1-7
[12] 30-day average of closing index prices from DJG-1-3 (^GSPC column)
[13-16] Expected dividends = [9]*[12]*(1+[10]) ^{n} ; Present value = expected dividend / (1+[11]+[19]) ^{n}
[17] Expected terminal value = expected dividend * (1+[11]) / [19] ; Present value = (expected dividend + expected terminal value) / (1+[11]+[19]) ^{n}
[18] = Sum([13-17]) present values.
[19] = [20] + [11]
[20] Internal rate of return calculation setting [18] equal to [12] and solving for the discount rate

CAPM Equity Risk Premium Results

IESE Business School Survey	5.5%	[1]
Duff & Phelps Report	5.5%	[2]
Damodaran (average)	4.8%	[3]
Garrett	4.9%	[4]
Average	**5.2%**	
Highest	**5.5%**	

CAPM Final Result

[1]	[2]	[3]	[4]
Risk-Free Rate	Proxy Beta	Risk Premium	**CAPM Result**
2.40%	0.872	5.5%	**7.2%**

[1] From DJG-7, risk-free rate exhibit
[2] From DJG-8, beta exhibit (avg. beta of proxy group)
[3] From DJG-10, equity risk premium exhibit
[4] = [1] + [2] * [3]

Cost of Equity Summary

Model	Cost of Equity
Discounted Cash Flow Model	6.7%
Capital Asset Pricing Model	7.2%
Average	**7.0%**

Market Cost of Equity vs. Awarded Returns

	[1]		[2]		[3]		[4]	[5]	[6]	[7]
	Electric Utilities		Gas Utilities		Total Utilities		S&P 500	T-Bond	Risk	Market
Year	ROE	#	ROE	#	ROE	#	Returns	Rate	Premium	COE
1990	12.70%	38	12.68%	33	12.69%	71	-3.06%	8.07%	3.89%	11.96%
1991	12.54%	42	12.45%	31	12.50%	73	30.23%	6.70%	3.48%	10.18%
1992	12.09%	45	12.02%	28	12.06%	73	7.49%	6.68%	3.55%	10.23%
1993	11.46%	28	11.37%	40	11.41%	68	9.97%	5.79%	3.17%	8.96%
1994	11.21%	28	11.24%	24	11.22%	52	1.33%	7.82%	3.55%	11.37%
1995	11.58%	28	11.44%	13	11.54%	41	37.20%	5.57%	3.29%	8.86%
1996	11.40%	18	11.12%	17	11.26%	35	22.68%	6.41%	3.20%	9.61%
1997	11.33%	10	11.30%	12	11.31%	22	33.10%	5.74%	2.73%	8.47%
1998	11.77%	10	11.51%	10	11.64%	20	28.34%	4.65%	2.26%	6.91%
1999	10.72%	6	10.74%	6	10.73%	12	20.89%	6.44%	2.05%	8.49%
2000	11.58%	9	11.34%	13	11.44%	22	-9.03%	5.11%	2.87%	7.98%
2001	11.07%	15	10.96%	5	11.04%	20	-11.85%	5.05%	3.62%	8.67%
2002	11.21%	14	11.17%	19	11.19%	33	-21.97%	3.81%	4.10%	7.91%
2003	10.96%	20	10.99%	25	10.98%	45	28.36%	4.25%	3.69%	7.94%
2004	10.81%	21	10.63%	22	10.72%	43	10.74%	4.22%	3.65%	7.87%
2005	10.51%	24	10.41%	26	10.46%	50	4.83%	4.39%	4.08%	8.47%
2006	10.32%	26	10.40%	15	10.35%	41	15.61%	4.70%	4.16%	8.86%
2007	10.30%	38	10.22%	35	10.26%	73	5.48%	4.02%	4.37%	8.39%
2008	10.41%	37	10.39%	32	10.40%	69	-36.55%	2.21%	6.43%	8.64%
2009	10.52%	40	10.22%	30	10.39%	70	25.94%	3.84%	4.36%	8.20%
2010	10.37%	61	10.15%	39	10.28%	100	14.82%	3.29%	5.20%	8.49%
2011	10.29%	42	9.92%	16	10.19%	58	2.10%	1.88%	6.01%	7.89%
2012	10.17%	58	9.94%	35	10.08%	93	15.89%	1.76%	5.78%	7.54%
2013	10.03%	49	9.68%	21	9.93%	70	32.15%	3.04%	4.96%	8.00%
2014	9.91%	38	9.78%	26	9.86%	64	13.52%	2.17%	5.78%	7.95%
2015	9.85%	30	9.60%	16	9.76%	46	1.38%	2.27%	6.12%	8.39%
2016	9.77%	42	9.54%	26	9.68%	68	11.77%	2.45%	5.69%	8.14%
2017	9.74%	53	9.72%	24	9.73%	77	21.61%	2.41%	5.08%	7.49%
2018	9.64%	37	9.62%	26	9.63%	63	-4.23%	2.68%	5.96%	8.64%
2019	9.66%	67	9.71%	32	9.68%	99	31.22%	1.92%	5.20%	7.12%
2020	9.44%	43	9.46%	34	9.45%	77	18.01%	0.93%	4.72%	5.65%
2021	9.40%	55			9.40%	55	18.01%	1.51%	4.24%	5.75%

[1], [2], [3] Average annual authorized ROE for electric and gas utilities, RRA Regulatory Focus: Major Rate Case Decisions; EEI Rate Review

[3] = [1] + [2]

[4], [5], [6] Annual S&P 500 return, 10-year T-bond Rate, and equity risk premium published by NYU Stern School of Business

[7] = [5] + [6] ; Market cost of equity represents the required return for investing in all stocks in the market for a given year

Proxy Company Debt Ratios

Company	Ticker	Debt Ratio
Atmos Energy Corp	ATO	38%
Chesapeake Utilities Corp	CPK	40%
New Jersey Resources Corporation	NJR	57%
NiSource Inc	NI	61%
Northwest Natural Holding Company	NWN	49%
ONE Gas Inc	OGS	62%
South Jersey Industries Inc	SJI	64%
Southwest Gas Holdings Inc	SWX	55%
Spire Inc.	SR	53%
Average		53%

Debt ratios from Value Line Investment Survey

Competitive Industry Debt Ratios

Industry	# Firms	Debt Ratio
Air Transport	21	85%
Hospitals/Healthcare Facilities	31	80%
Hotel/Gaming	66	77%
Brokerage & Investment Banking	31	76%
Retail (Automotive)	32	72%
Food Wholesalers	15	68%
Retail (Grocery and Food)	15	68%
Rubber& Tires	2	67%
Bank (Money Center)	7	67%
Advertising	49	67%
Computers/Peripherals	46	67%
Auto & Truck	26	66%
Real Estate (Operations & Services)	51	66%
Retail (Special Lines)	76	64%
Cable TV	11	63%
Oil/Gas Distribution	21	63%
Packaging & Container	26	62%
Telecom. Services	42	61%
Recreation	60	61%
Broadcasting	28	60%
Transportation (Railroads)	4	60%
R.E.I.T.	238	60%
Power	50	60%
Telecom (Wireless)	17	59%
Transportation	17	59%
Beverage (Soft)	32	58%
Utility (Water)	14	57%
Retail (Distributors)	68	57%
Office Equipment & Services	18	57%
Aerospace/Defense	73	57%
Household Products	118	56%
Computer Services	83	56%
Green & Renewable Energy	20	56%
Chemical (Diversified)	4	55%
Trucking	34	55%
Farming/Agriculture	36	54%
Environmental & Waste Services	58	54%
Apparel	39	54%
Paper/Forest Products	11	54%
Retail (Online)	60	53%
Chemical (Basic)	35	53%
Real Estate (Development)	19	52%
Business & Consumer Services	160	52%
Coal & Related Energy	18	52%
Construction Supplies	48	51%
Total / Average	**1,930**	**61%**

http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/dbtfund.htm

Weighted Average Rate of Return Proposal

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long-Term Debt	50.0%	3.98%	1.99%
Common Equity	50.0%	8.50%	4.25%
Total	100.0%		6.24%

Hamada Model

Unlevering Beta

Proposed Debt Ratio	45%	[1]
Proposed Equity Ratio	55%	[2]
Debt / Equity Ratio	81%	[3]
Tax Rate	21%	[4]
Equity Risk Premium	5.5%	[5]
Risk-free Rate	2.4%	[6]
Proxy Group Beta	0.87	[7]
Unlevered Beta	0.53	[8]

Relevered Betas and Cost of Equity Estimates

[9]	[10]	[11]	[12]
Debt Ratio	D/E Ratio	Levered Beta	Cost of Equity
0%	0%	0.531	5.32%
20%	25%	0.636	5.89%
30%	43%	0.711	6.30%
40%	67%	0.810	6.85%
50%	100%	0.950	7.62%
55%	122%	1.043	8.13%
60%	150%	1.160	8.77%

[1] Company proposed debt ratio

[2] Company proposed equity ratio

[3] = [1] / [2]

[4] Tax rate

[5] Equity risk premium from Exhibit DJG-11

[6] Risk-free rate from Exhibit DJG-11

[7] Average proxy beta from Exhibit DJG-11

[8] = [7] / (1 + (1 - [4]) * [3])

[9] Various debt ratios (Garrett proposed highlighted)

[10] = [9] / (1 - [9])

[11] = [8] * (1 + (1 - [4]) * [10])

[12] = [6] + [11] * [5]

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, David J. Garrett, hereby state that the facts set forth in my Direct Testimony, OCA Statement 2, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 20, 2022
*327282

Signature: ______________________
David J. Garrett

Consultant Address: Resolve Utility Consulting, PLLC
101 Park Avenue
Suite 1125
Oklahoma City, OK 73102

OCA Statement 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	Docket No. R-2021-3030218
UGI UTILITIES, INC. – GAS DIVISION	)	

DIRECT TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 20, 2022

EXETER

ASSOCIATES, INC.

10480 Little Patuxent Parkway, Suite 300

Columbia, Maryland 21044

TABLE OF CONTENTS

Page

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Canisius College in Buffalo, New York in 1981 with a Bachelor of Science Degree in Marketing. In 1985, I received a Master's Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation ("NFGD") as a Management Trainee in the Research and Statistical Services ("RSS") Department. I was promoted to Supervisor RSS in January 1987. While employed with NFGD, I conducted various financial and statistical analyses related to the company's market research activity and state regulatory affairs. In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's ("NFG Supply's") rate department where my responsibilities included utility cost-of-service and rate design analysis, expense and revenue requirement forecasting, and activities related to federal regulation. I was also responsible for preparing NFG Supply's Federal Energy Regulatory Commission ("FERC") Purchased Gas Adjustment ("PGA") filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFGD's 1307(f) proceedings.

In April 1990, I accepted a position as a Utility Analyst with Exeter. In December 1992, I was promoted to Senior Regulatory Analyst. Effective April 1996, I became a Principal of Exeter. Since joining Exeter, I have specialized in evaluating the gas purchasing practices and policies of natural gas utilities, utility class cost-of-service and rate design analyses, sales and rate forecasting, performance-based incentive regulation, revenue requirement analysis, the unbundling of utility services, and evaluation of customer choice natural gas transportation programs.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON UTILITY RATES IN REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony on nearly 400 occasions in proceedings before the FERC and utility regulatory commissions in Arkansas, Delaware, Georgia, Illinois, Indiana, Louisiana, Maine, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, Ohio, Rhode Island, South Carolina, Texas, Utah, and Virginia, as well as before the Pennsylvania Public Utility Commission ("Commission").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On January 28, 2022, UGI Utilities, Inc. – Gas Division ("UGI Gas" or "Company") filed a request with the Commission to increase its distribution base rates by $82.7 million, or 12.4 percent ("Filing"). The increase proposed for Residential customers is 18.1%. Exeter was retained by the Pennsylvania Office of Consumer Advocate ("OCA") to review the reasonableness of the cost-of-service study and rate design proposals included in UGI Gas' Filing. My testimony addresses UGI Gas' cost-of-service study and rate design proposals.

Q. HAVE YOU PREPARED EXHIBITS TO ACCOMPANY YOUR TESTIMONY?

A. Yes, I have. Schedules JDM-1 through JDM-3 are attached to my direct testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. My findings and recommendations are as follows:

- Typical of a natural gas distribution company ("NGDC"), a significant percentage of UGI Gas' plant, nearly 55 percent, is comprised of transmission and distribution mains (collectively "Mains") investment;

- UGI Gas' class cost of service study misallocates its Mains plant investment and related costs, producing study results that do not reasonably reveal an accurate indication of class allocated cost responsibilities. UGI Gas' study also misallocates several other cost items including manufactured gas remediation costs, forfeited discounts, and reconnection fees.

- The Peak & Average Study presented by the OCA in this proceeding reflects an allocation of Mains investment that is consistent with established Commission precedent and cost-of-service principles and corrects other misallocations of costs in the Company's study;

- The revenue distribution in this proceeding should be guided by the results of the OCA's Peak & Average Study;

- UGI Gas' current monthly Residential customer charge is $14.60. The Company is proposing to increase this charge to $19.95, or by 37 percent. UGI Gas' proposal to increase the Residential customer charge to $19.95 should be rejected, and the charge should be established at no higher than $16.00;

- The balancing service charges to be assessed to non-Choice transportation customers under Rate NNS ("No-Notice Service") and Rate MBS (Monthly Balancing Service) which are based on the interstate pipeline charges assessed to UGI Gas should not be revised as discussed in my testimony;

- UGI Gas' current practice of assessing Rate LFD transportation customers a charge for released interstate pipeline capacity based on the Company's weighted average cost of firm transportation capacity, or demand ("WACOD"), which includes 50 percent of the demand charges associated with peaking services, should be extended to Rate XD customers that accept an assignment of capacity; and

- UGI Gas' proposed Weather Normalization Adjustment ("WNA") mechanism should be rejected. If not rejected, there should be a 3% deadband included like the pilot WNA Rider utilized by Columbia Gas of Pennsylvania.

Q. AS AN INITIAL MATTER, SEVERAL OF THE RATE SCHEDULES INCLUDED IN THE COMPANY'S TARIFF REFER TO THE FORMER NORTH, CENTRAL, AND SOUTH RATE DISTRICTS. PLEASE EXPLAIN HOW THESE RATE DISTRICTS WERE ESTABLISHED.

A. Prior to October 1, 2018, UGI Gas had two wholly-owned subsidiaries that were natural gas distribution companies ("NGDCs") subject to this Commission's jurisdiction. Those subsidiaries were UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas ("UGI CPG"). UGI PNG began its operations as a UGI Gas company on August 24, 2006, the effective date of UGI Corporation's purchase of the natural gas distribution assets of the former PG Energy Division of Southern Union Company. UGI CPG, formerly PPL Gas Utilities Corporation, was acquired by UGI Corporation effective October 1, 2008.

On March 8, 2018, UGI Gas filed a Petition with the Commission to merge UGI PNG and UGI CPG into UGI Gas, and to thereafter operate as three rate districts adopting the former tariffs of UGI Gas, UGI PNG, and UGI CPG. A *Joint Petition for Approval of Settlement of All Issues* ("Merger Settlement") was subsequently reached and approved by the Commission in an Order entered on September 20, 2018 at Docket Nos. A-2018-3000381, A-2018-3000382, and A-2018-3000383 ("Merger Order").

The merger was completed on October 1, 2018 and UGI Gas commenced operations under three rate districts. UGI PNG began operating as the North Rate District, UGI CPG began operating as the Central Rate District, and UGI Gas began operating as the South Rate District. Each Rate District maintained separate: (a) base rates; (b) gas supply portfolios; (c) purchased gas cost ("PGC") rates; (d) sets of rules applicable to natural gas suppliers ("NGS") serving Choice and non-Choice transportation customers; and (e) tariffs.

On January 28, 2019, UGI Gas filed for a base rate increase at Docket No. R-2018-3006814 ("2019 Rate Case"). In that proceeding, the Company proposed to consolidate its base rate districts and operate under a single uniform tariff with uniform Residential and Commercial base rates and associated surcharges and riders across its system. The 2019 Rate Case was resolved by a settlement which was approved by the Commission in an Opinion and Order entered October 4, 2019. With a limited number of exceptions, the 2019 Rate Case settlement provided for the adoption of single uniform tariff for all rate districts. Several of those rate district exceptions currently remain in place.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Including this introductory section, my testimony is divided into seven sections. In the section following the introduction section, I detail the reasons that support a finding that UGI Gas' cost of service study produces an inaccurate indication of the allocated costs of serving the Company's various customer classes. The next section addresses class revenue requirement allocations. The fourth section of my testimony addresses UGI Gas' proposed Residential rate design. The next section of my testimony addresses UGI Gas' proposed charges for service under Rates NNS and MBS. The sixth section of my testimony addresses the charges assessed for interstate pipeline capacity released to Rate XD transportation customers. The final section of my testimony addresses UGI Gas' proposed WNA mechanism.

II. COST ALLOCATION

Q. PLEASE DESCRIBE THE COST OF SERVICE STUDY SUBMITTED BY UGI GAS IN THIS PROCEEDING.

A. UGI Gas' cost of service study is presented by Ms. Constance E. Heppenstall of Gannett Fleming Valuation & Rate Consultants, LLC. In a cost of service study, costs are assigned to the various customer classes based on, to the best ability of the cost practitioner performing the study to determine, the classes that have "caused" the utility to incur such costs. Customers cause the utility to incur costs by demanding the services for which the Company incurs costs.

Ms. Heppenstall claims that UGI Gas' study is based on the Average and Excess Demand Method ("A&E method") of allocating costs to service classifications (customer classes). The A&E method is identified in *Gas Rate Fundamentals* (published in 1987 by the American Gas Association's Rate Committee), in which it is described. The three basic categories of cost responsibility identified in UGI Gas' study are commodity, capacity, and customer costs.

Commodity costs are the costs that tend to vary with the quantity of gas used. In UGI Gas' study, commodity costs include production investment and operation and maintenance costs. Commodity costs were allocated to customer classes on the basis of average daily sales volumes.

Capacity costs are costs associated with meeting the peak demands of the UGI Gas system. Capacity costs include transmission and distribution expenses, and capital costs not associated with the customer cost category. Capacity costs were allocated to the customer classes on a combined basis of average use and excess demand (demand in excess of average use). For presentation purposes, commodity and capacity costs have been combined into a volumetric function in the Company's cost study.

Customer costs are costs associated with serving customers regardless of their usage or demand characteristics. Customer costs include the expenses and capital costs related to meters, services, and expenses related to meter reading and billing. Customer costs were allocated to the customer classes on the bases of the numbers of meters, services, and customers.

Q. PLEASE IDENTIFY THE CUSTOMER CLASSES INCLUDED IN UGI GAS' COST OF SERVICE STUDY.

A. The Company's cost of service study includes the following customer classes:

- Residential (Rates R and RT);
- Non-Residential (Rates N and NT);
- Delivery Service (Rate DS);
- Large Firm Delivery Service (Rate LFD);
- Extended Large Firm Delivery Service (Rate XD); and
- Interruptible Service (Rate IS).

Rates R and N are sales services provided by UGI Gas, and Rates RT and NT are transportation services. Rates DS, LFD, and XD are also transportation services. Historically, both sales and transportation service were available under Rate IS; however, the Company no longer provides sales service under Rate IS.

Q. HOW DID UGI GAS ALLOCATE ITS MAINS PLANT INVESTMENT, ITS SINGLE LARGEST RATE BASE ITEM?

A. The investment in Mains associated with serving Rate XD customers is directly assigned to this class. For all other classes, the remaining Mains investment was allocated using Ms. Heppenstall's version of the A&E method. Under the A&E method described in *Gas Rate Fundamentals*, the average daily demand and the total system coincident peak demand of each customer class are determined. The ratio developed by dividing average demands by total system coincident peak demand is referred to as the system average load factor. Under the A&E method described in *Gas Rates Fundamentals*, a portion of main investment equal to the system average load factor is classified as commodity-related and is allocated to class based on average daily demands. The balance, or the difference between total system coincident peak demand and average daily demands (i.e., 1 minus system average load factor), is considered Excess Demand. Excess Demand is allocated to each class based on each class' relative contribution to the total non-coincident peak demand of all the classes served.[1]

In summary, the A&E method claims to separately identify those costs associated with meeting average demands and allocates those costs to customer class based on average demands. It also separately identifies the costs associated with meeting demands in excess of average demands and allocates those costs to customer classes based on the non-coincident peak demands of each class. The A&E method presented in *Gas Rates Fundamentals* assumes a significant difference between each customer class' demand at the time of system peak (coincident peak demand), and each customer class' non-coincident peak demand. For illustrative purposes, shown below are the coincident and non-coincident peak demands of the customer classes included in the A&E method example presented in *Gas Rates Fundamentals*.

[1] The coincident peak demand of a customer class is that class' demand at the time of system peak. The non-coincident peak demand of a customer class is that class' maximum demand, regardless of whether that maximum demand occurred at the time of system peak.

Table 1. Class Demands Reflected in *Gas Rates Fundamentals* - A&E Method

	Peak Demand (Mcf)	
Class of Service	**Coincident**	**Non-Coincident**
Residential	1,570	3,000
Commercial	714	1,250
Industrial	599	1,100
Interruptible	1,284	3,000
Total	**4,167**	**8,350**

Q. DOES THE A&E METHOD PRODUCE A REASONABLE ALLOCATION OF MAINS COSTS ON THE UGI GAS SYSTEM?

A. No, it does not. In *Gas Rate Fundamentals*, the A&E method is described as an approach that captures the cost responsibility related to both the average annual volumetric use of capacity and to the additional capacity required to meet maximum system loads (peak demand). As explained later in my testimony, the A&E method, while claiming to recognize the importance of average annual volumetric use, actually assigns excessive cost responsibility to peak demands on the UGI Gas system. In addition, on systems such as UGI Gas' with little or no customer class load diversity, the A&E method collapses into a pure peak allocation method. That is, 100 percent of Mains investment would be allocated based on each class' contribution to the total system peak under the A&E method, and no costs would be allocated on average demands.

Q. WHAT DO YOU MEAN BY LOAD DIVERSITY?

A. Load diversity refers to the difference between the total system demand at the time of peak and the sum of the total non-coincident peak demands of each of the customer classes. The greater this difference, the greater the load diversity. Diversity can be captured in the concept of a load diversity ratio. A load diversity ratio can be calculated by dividing non-coincident peak demand by total system demand at the time of peak. Since the system peak demand cannot be greater than the sum of all class non-coincident peaks, the load diversity factor cannot be less than 1.0.

Q. PLEASE DEMONSTRATE HOW THE A&E METHOD COLLAPSES INTO A PURE PEAK METHOD WHEN NO SYSTEM LOAD DIVERSITY EXISTS.

A. There are several ways to demonstrate that the A&E method, while purporting to give significant weight to average demands, in fact, does not. One way is simply to examine the algebraic logic of the A&E formula. In algebraic terms, peak demands can be stated as the sum of average demands and excess demands:

(1) Peak Demand = Average Demand + Excess Demand.

Excess Demand, however, is simply Peak Demand less the Average Demand:

(2) Excess Demand = Peak Demand - Average Demand.

Substituting equation (2) for the Excess Demand term of equation (1) yields:

(3) Peak Demand = Average Demand + Peak Demand - Average Demand.

Equation (3) collapses into a useless identity:

(4) Peak Demand = Peak Demand

The algebra above holds true when there is no system diversity and average demands are weighted by system load factor and peak demands are weighted by one-minus-system load factor, as the *Gas Rate Fundamentals* description requires. Stated differently, the formula used by Ms. Heppenstall is:

$$\text{Allocation} = \text{Average}_{\text{Demand}} + (\text{Peak}_{\text{Demand}} - \text{Average}_{\text{Demand}})$$

The term in the parentheses is Excess Demand, but the whole right-hand side of the equation after the = sign is simply the definition of peak demand. Thus, where, as here, there is no load diversity, the algebra underpinning of the A&E allocation methodology is shown to be identical to the allocation of costs on a pure peak demand basis.

A second way to show that the A&E method appears to give substantial weight to average demands but, in fact, does not, is through an arithmetic example utilizing UGI Gas' customer classes. Table 2 below shows the resulting pure peak allocation factors and the resulting A&E allocation factors reflected in the study filed by UGI Gas with its application when the factors are developed consistent with the *Gas Rate Fundamentals* description.

Table 2. Comparison of Average & Excess and Peak Factors

Rate Class (a)	**Average Demand** (b)	**Peak Demand** (c)	**Excess Demand** (d)	**A&E Factor** (e)	**Peak Factor** (f)
Residential (R)	142,485	649,604	507,119	50.22%	50.22%
Non-Residential (N)	85,232	431,709	346,477	33.37%	33.37%
Large Firm Delivery Service (LFD)	64,765	115,419	50,654	8.92%	8.92%
Delivery Service (DS)	26,335	96,848	70,513	7.49%	7.49%
Total	**318,817**	**1,293,580**	**974,763**	**100.00%**	**100.00%**

Notes:
Load Factor = 24.6 percent.
A&E Factor = (Class Average Demand / Total Average Demand) x Load Factor + (Class Excess Demand / Total Excess Demand) x (1 – Load Factor).

This table shows that when average demands are weighted by the system load factor and when peak demands are based on the maximum system load, the resulting A&E allocation factors are identical to the pure peak allocation factors. As shown above, the A&E method, while appearing to arithmetically consider class average demands in the allocation of demand related costs, effectively provides no weight to average demands.

Q. HOW DO MS. HEPPENSTALL'S A&E ALLOCATION FACTORS DIFFER FROM THOSE REFLECTED IN TABLE 2?

A. Table 3 below shows the pure peak allocation factors calculated in Table 2 and the A&E allocation factors calculated by Ms. Heppenstall for each customer class in the study filed by UGI Gas in its application.

Table 3. Comparison of Company Peak and Average & Excess Allocation Factors

Rate Class	Pure Peak Factor	Company A&E Factor	Difference
Residential (R)	0.5022	0.4685	(0.0337)
Non-Residential (N)	0.3337	0.3058	(0.0279)
Delivery Service (DS)	0.0749	0.0728	(0.0021)
Large Firm Delivery Service (LFD)	0.0892	0.1061	0.0169
Interruptible Delivery Service (IS)	0.0000	0.0468	0.0468

For practical purposes, Mr. Heppenstall's A&E allocation factors and pure peak allocation factors are comparable, the difference being UGI Gas' inclusion of the average demands of interruptible customers. I would further note that in the cost of service study presented by Mr. Heppenstall, the excess demands of interruptible customers are assumed to be zero. As shown in Table 1, this is inconsistent with the application of the A&E method discussed in *Gas Rates Fundamentals*. I address the allocation of peak demand costs to interruptible customers later in my testimony.

Q. WHAT IS THE IMPORTANCE OF THIS FINDING THAT THE AVERAGE AND EXCESS ALLOCATION METHOD DOES NOT GIVE SIGNIFICANT WEIGHT TO ANNUAL OR AVERAGE DEMANDS?

A. Ms. Heppenstall apparently believes, as I strongly believe, that a significant portion of UGI Gas' Mains plant and related expenses are properly allocated on average demands. In her cost of service study, Ms. Heppenstall shows that she intended to weight average demands 42.1 percent (UGI Gas Exhibit D, Schedule F, page 18), but in actuality, Ms. Heppenstall's Mains allocation factors are nearly identical to the results obtained when average demand allocation factors are weighted at zero, and pure peak allocation factors are weighted at 100 percent. I agree with Ms. Heppenstall that a significant portion of Mains costs should be allocated on average demands, and I will further address this subject later in my testimony when I present a class cost of service study that does, in fact, allocate a portion of Mains costs on the basis of average demands.

Q. IS IT APPROPRIATE FOR UGI GAS TO ALLOCATE ITS DISTRIBUTION SYSTEM COSTS ON CLASS PEAK DEMANDS ONLY?

A. No. The peak day demands utilized in UGI Gas' cost of service study are based on demands which would be expected to occur on the coldest day during the last 30 years (design peak day demand). If Ms. Heppenstall's allocation of UGI Gas' Mains costs on the basis of design day peak demands were in accord with the principle of cost-causality then demands for natural gas deliveries only under design peak day weather conditions would have to be the only cause for the existence and customer utilization of UGI Gas' Mains for gas delivery service. Design peak day demands represent the maximum demands that are expected under the most severe weather assumptions used for planning purposes. While a portion of UGI Gas' Mains costs are associated with, and hence, should be allocated on peak demands, it is wrong to claim that most Mains costs are caused by end-use consumer demands on the coldest day which is experienced in UGI Gas' service territory every 30 years or so. Quite simply, if UGI Gas' customers had a demand for gas only on design peak days, there wouldn't be a UGI Gas distribution system. The costs of delivered gas supplies on that one design peak day would be prohibitively high, and the cost of delivering gas through UGI Gas' distribution system on that one day simply could not compete with alternative energy costs.

Q. IF LOCAL GAS DISTRIBUTION SYSTEMS ARE NOT BUILT SOLELY TO MEET THE MOST SEVERE DAY WHICH MAY BE EXPERIENCED, WHY DO NGDCS INCUR DISTRIBUTION MAINS INVESTMENT COSTS?

A. The basic reason, of course, why NGDCs like UGI Gas invest in their distribution systems is to meet the annual demands for gas by end-use customers. This is the reason for the existence of the NGDC in the first place. Without sufficient annual gas usage over which to amortize the annual costs of providing service, there would be no gas distribution system. Additionally, as I will describe later, a small amount of the total cost of distribution service is related to installing a system with enough throughput capacity to meet peak demands as well as annual demands. Because Mains exist and are related to both annual demands and peak demands, both annual and peak demands must be recognized in the allocation of Mains costs, if the allocation is to be in accordance with the principle of cost-causality.

Q. HOW DOES UGI GAS DETERMINE WHETHER TO INVEST IN ITS DISTRIBUTION SYSTEM AND EXTEND ITS MAINS TO CONNECT CUSTOMERS?

A. UGI Gas' decisions to extend its Mains are guided by its Mains Extension Policy.

Q. DOES THE COMPANY'S MAINS EXTENSION POLICY CONSIDER PEAK DAY DEMANDS?

A. No, it does not. With the general exception of Mains extension up to 150 feet for new customers, estimated annual base rate revenues are considered in the Company's Mains extension decision making process. The Company's base rate revenues are primarily collected on a volumetric basis. This policy is set forth in Item 5 of the Rules and Regulations of the Company's current tariff. Therefore, anticipated annual customer usage is the primary factor influencing UGI Gas' Main extension decision-making process. The exception for mains extension of up to 150 feet is a very recent change to the Company's Main extension policy, which was adapted in the Settlement approved in the Company's most recent prior base rate case in Docket No. R-2019-3015162. Therefore, nearly all of UGI Gas Mains extensions to current customers served from its distribution system was decided based on customer annual base rate revenues

Q. WHY IS IT PROPER TO ALLOCATE MAINS INVESTMENT ON THE BASIS OF ANNUAL AS WELL AS PEAK DEMANDS?

A. The allocation of Mains investment costs on the basis of both annual and peak demands is in accord with the principle of allocating costs on the basis of cost causality. Natural gas is of little or no value to an end user if that gas cannot be delivered to the location of the gas burning equipment. UGI Gas' distribution system imparts locational value to the natural gas delivered across that system by allowing for the movement of that gas from its acquisition source to each customer's location. UGI Gas' distribution system exists, and related costs are incurred, to deliver gas to its customers whenever, over the course of each year, its customers demand gas. In other words, UGI Gas' system was built and costs were incurred to deliver gas both at the time of peak system demand and generally throughout the year. Because costs are incurred to deliver gas generally throughout the year, and additional costs are incurred to meet peak demands, UGI Gas' Mains costs must be allocated on the basis of both annual and peak demands if those costs are to be allocated in accord with the principle of cost causality. UGI Gas' failure to properly allocate its Mains costs associated with average demands, and its allocation of its Mains system investment costs on peak demands, violates the principle of cost-causality.

Q. PLEASE EXPLAIN YOUR STATEMENT THAT COSTS ARE INCURRED TO DELIVER BOTH ANNUAL AND PEAK VOLUMES ACROSS UGI GAS' SYSTEM.

A. UGI Gas' firm customers are projected to move approximately 325,000,000 Mcf across UGI Gas' system during the cost of service study annual test period. This equates to an average demand of about 890,300 Mcf each day. UGI Gas' peak demand is about 2,115,000 Mcf. UGI Gas could not meet its customers' annual gas demands with a system capability any smaller than 890,300 Mcf. In other words, if there were no variance in the daily demands on UGI Gas' system, the capacity of that system would have to be designed to accommodate the daily movement of 890,300 Mcf just to meet annual demands. To meet peak demands, UGI Gas' system capacity must be 2.4 times greater than 890,300 Mcf. Thus, some costs are related to the average deliveries each day on the UGI Gas' system, and some costs are related to the movement of gas when demands are above the average demand.

Rational investment decision analysis requires the consideration of annual volumes delivered across a NGDC's system. A gas distribution system would not exist if all demand related costs were the responsibility of peak demands. A viable gas market is dependent upon the ability to amortize delivery costs over a sufficient volume of service so as to result in a unit cost that can be recovered at a price at which gas can be sold and still compete with other energy sources. The association of costs with annual as well as peak demands, and the allocation of costs on the basis of both annual and peak demands for gas are absolutely essential to the economic feasibility of a gas delivery system. To largely ignore annual demands and allocate total Mains costs on peak demands, as UGI Gas' cost of service study does, is inconsistent with the consideration of annual demands which are absolutely essential to the economic justification of the very costs being allocated.

Q. HOW DO THE COSTS OF PROVIDING FOR THE MOVEMENT OF GAS TO MEET PEAK DEMANDS COMPARE TO THE COSTS OF PROVIDING FOR THE MOVEMENT OF GAS TO MEET LESSER DEMANDS?

A. Many of the costs associated with the distribution delivery system are not significantly affected by pipe size. These costs would include planning, surveying, excavating, hauling, pipe bed preparation, unloading and stringing of pipe, municipal inspection, backfill, and pavement and sidewalk replacement. Therefore, total costs do not increase at a one-to-one ratio with increases in maximum demands. The additional costs associated with meeting elevated demands are largely related to the cost of the pipe itself.

Moreover, throughput capability increases not at a one-to-one ratio with the size of the pipe, but at a rate equal to the square of the pipe's diameter. Doubling the diameter of a pipe, for example, increases its capacity by four times the original capacity. Thus, the additional costs of providing additional capacity are lower than the average costs of providing capacity. This means that the costs associated with providing capacity for the movement of average demands are greater on a unit basis than are the costs associated with providing capacity for additional demands. UGI Gas' distribution system exists to deliver annual system requirements. There are costs that are uniquely associated with meeting peak demands, and as such peak demands should bear some cost responsibility.

Q. ARE GAS FLOWS ON THE DESIGN PEAK DAY SO IMPORTANT THAT MOST OF UGI GAS' TOTAL TRANSMISSION AND DISTRIBUTION SYSTEM COSTS ARE DIRECTLY RELATED TO, AND CAUSED BY, PEAK DAY DEMAND REQUIREMENTS?

A. No. Peak demands are not the major cause of UGI Gas' demand related Mains cost, and it is therefore wrong to allocate Mains-related costs on the basis of peak demands, as Ms. Heppenstall has done. Only the marginal costs incurred to meet peak demands above other demands are caused by, or directly related to, peak requirements. The UGI Gas delivery system would not be viable and simply would not exist if the only demand for gas was the demand associated with extreme weather conditions. The UGI Gas delivery system exists because the total annual demand for gas is sufficient to warrant its existence. It is an extreme and erroneous view that the Mains costs associated with UGI Gas' delivery network are caused by peak day demands. Because UGI Gas' system exists to deliver annual gas requirements, but some additional costs are related to the delivery of gas during periods of elevated demand, it is appropriate to allocate its Mains costs on both annual and peak demands. The allocation of distribution system-related costs largely on the basis of peak demands, as UGI Gas has done, misallocates substantial costs.

Q. TO WHAT EXTENT DO THE COSTS OF MEETING PEAK GAS FLOW REQUIREMENTS EXCEED THE COSTS OF MEETING AVERAGE GAS FLOW REQUIREMENTS?

A. UGI Gas' firm peak day demand is about 2.4 times its firm average demand. A pipe's cross-sectional area, and correspondingly its capacity, varies with the square of its radius. Therefore, doubling the size of a pipe's radius (or diameter), increases the capacity of the pipe four-fold. For example, doubling the diameter of a 2-inch pipe to 4 inches increases the capacity by 4 times the capacity of the 2-inch pipe. Increasing the diameter of a 2-inch pipe to 8 inches increases the capacity by 16 times. The costs of meeting increased flow requirements that are caused by, or associated with, elevated demands is answered by the relationship of the change in total capacity costs and to the change in capacity.

I explained earlier that since many capacity costs do not change significantly with the size of the pipe, the increased costs associated with meeting increased capacity requirements is expected to be small. Indeed, it is largely these economies of scale that lead to falling average costs of service and the provision of gas distribution service more economically by one monopoly provider, like UGI Gas, rather than by many competing providers.

Q. DO YOU HAVE UGI GAS-SPECIFIC DATA ILLUSTRATING THAT THE INCREASED COSTS ASSOCIATED WITH MEETING INCREASED DEMANDS ARE SMALL?

A. Yes. Table 4 identifies the average original per-foot to install distribution mains for the pipe sizes with a total investment in excess of $100 million.

Table 4. Cost of Installed Distribution Mains	
Diameter (inches)	**Average Cost (per foot)**
2	$21.52
4	$29.68
6	$37.42
8	$56.21
12	$95.56

As shown on Table 4 the average cost of installing a 2-inch main was $21.52 per foot, while the average cost of installing a 4-inch main was $29.68 per foot. Thus, for a fourfold increase in capacity, UGI Gas' total average costs increased by 34 percent (($29.68 - $21.52) / $21.52). Based on this example, a doubling of the pipe size (and hence a quadrupling of capacity) increased capacity costs by 38 percent, indicating that increased demands above average demands can be accommodated at increased distribution mains costs that are approximately 9 percent (38 percent / fourfold increase in capacity) of the costs of meeting average demands:

2-inch	**4-inch**	**Cost per Foot Increase**	**Percent**	**Capacity Increase**	**Cost of Peak**
(a)	(b)	(c) = (b)-(a)	(d) = (c)/(a)	(e)	(f) ~ (d)/(e)
$21.52	$29.68	$8.16	38 %	4	9 %

Table 4 also indicates that the average cost of installing an 8-inch main was $56.21 per foot. Thus, for a 16-fold increase in capacity, UGI Gas' total average costs increased by more than 161 percent (($56.21 - $21.52) / $21.52) over the cost of a 2-inch pipe. Based on this example, a quadrupling of pipe size (and hence a 16-fold increase in capacity) increased capacity costs by about 161 percent, indicating that increased demands above average demands can be accommodated at an increased distribution mains costs that are approximately 10 percent (161 percent / 16-fold increase in capacity) of the costs of meeting average demands:

		Cost per Foot		Capacity	Cost of
2-inch	**8-inch**	**Increase**	**Percent**	**Increase**	**Peak**
(a)	(b)	(c) = (b)-(a)	(d) = (c)/(a)	(e)	(f) ~ (d)/(e)
$21.52	$56.21	$34.69	161%	16	10 %

Given these two UGI Gas-specific examples above, significantly less than half of distribution mains costs are associated with meeting elevated peak demand requirements and could be allocated based on peak demands, and the remainder is related to customers' annual demands for natural gas and could be allocated on average demands.

Q. PLEASE COMPARE YOUR VIEWS ON HOW MAINS RELATED COSTS SHOULD BE ALLOCATED WITH UGI GAS' VIEW.

A. UGI Gas supports the allocation of its Mains costs 42.1 percent on the basis of average demands and 57.9 percent on the basis of excess demands (UGI Gas Exhibit D, Schedule F, page 18). The A&E method utilized by Ms. Heppenstall results in an allocation of Mains costs essentially based on a pure peak method of allocation. I have shown that there are incremental costs, small though they may be, associated with building a gas delivery system with sufficient capacity to meet peak demands, which are higher than average demands.

Under Ms. Heppenstall's cost allocation procedures essentially no Mains costs are allocated on the basis of customer average demands, which is the basic service that UGI Gas provides and the very reason UGI Gas exists in the first place. UGI Gas' proposed cost allocation method, which in fact does not allocate costs on the basis of the primary service (annual delivery of gas) that UGI Gas provides, and without which the UGI Gas distribution system would not exist, violates the principle of allocating costs in accord with cost-causality. On the other hand, my subsequent recommendation to actually accomplish the allocation of a portion of Mains costs on the basis of average demands that cause those costs, and the allocation of a portion of Mains costs on the basis of the peak demands that cause the peak-related distribution costs, is consistent with Ms. Heppenstall's belief and her attempt to allocate a portion of costs on average demands, and comports with the principle that costs should be allocated to the service units that cause the costs.

Q. HOW CAN MAINS INVESTMENT COSTS BE PROPERLY ALLOCATED?

A. The additional costs of providing capacity in order to meet peak demands, as opposed to lesser demands, should be allocated on a peak demand basis. I demonstrated earlier that no more than approximately 10 percent of UGI Gas' Mains costs are associated with meeting increased demands, and hence, a small portion of Mains costs should be allocated on the basis of peak demands. I conservatively recommend that 50 percent of UGI Gas' Mains system costs, instead of a lesser amount, be allocated on the basis of peak demands. The remaining 50 percent of UGI Gas' Mains costs, being related to, or caused by, UGI Gas' annual gas requirements, should be allocated on annual or average demands. This 50 percent peak/50 percent average (Peak & Average) allocation is a conservative recommendation regarding the recognition of annual, or average, deliveries, as it recommends far less than the approximately 90 percent cost responsibility associated with annual demands.

Q. HAS THIS COMMISSION PREVIOUSLY APPROVED USE OF THE PEAK & AVERAGE METHOD?

A. Yes. In Columbia Gas of Pennsylvania, Inc. ("Columbia") Docket No. R-2020-3018835, the Commission recently endorsed the use of the Peak & Average Method. In that proceeding the Commission found:

> Furthermore, distribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality. It is not reasonable to allocate distribution mains investment based solely on design peak day demands as in Columbia Gas' Customer-Demand ACCOSS. The basic reason Columbia Gas invests in its distribution system is to meet the annual demands for gas by customers. Additionally, a portion of the total cost of distribution service is related to installing a system with enough throughput capacity to meet design peak demands in excess of annual demands. (Order at 217).
>
> For all these reasons, we find that the Peak & Average allocation methodology is the most appropriate allocation methodology to use in this proceeding because it is based on the premise of load-based investment. Accordingly, we shall deny Columbia Gas' Exceptions Nos. 18 and 19, and the OSBA's Exception No. 1, and PSU's Exception No. 1 as they relate to their respective ACCOSS arguments and adopt the OCA's P&A ACCOSS as proffered by OCA Witness Mr. Mierzwa in OCA Statement No. 4, at 5-33, and the OCA's Main Brief, at 150-155. (Order at 218).

A. The Commission has also endorsed the Peak & Average Method in other proceedings. In National Fuel Gas Distribution's ("NFGD") 1994 base rate proceeding, the Commission accepted the Peak & Average methodology, stating, "[t]he Peak and Average method that allocates Mains equally is a sound and reasonable method of cost allocation and should remain intact." <u>Pa. P.U.C. v. National Fuel Gas Distribution Co</u>., 83 Pa. PUC 262 (1994). See also, <u>Pa. P.U.C. v. National Fuel Gas Distribution Co</u>., 73 Pa. PUC 552 (1990); <u>Pa. P.U.C. v. Equitable Gas Co</u>., 73 Pa. PUC 301 (1990); <u>Pa.</u>

P.U.C. v. National Fuel Gas Distribution Corp. 72 Pa. PUC 1 (1989); Pa. P.U.C. v. Peoples Gas Co., 69 Pa. PUC 138 (1989).

Q. HAVE OTHER COMMISSIONS ACCEPTED THE USE OF THE PEAK AND AVERAGE METHOD?

A. Yes. The Indiana Utility Regulatory Commission ("IURC") has strongly endorsed the use of the Peak & Average methodology. See In re Citizens Gas & Coke Utility, IURC Cause No. 42767, (Oct. 19, 2006). The IURC found that the Peak & Average method was the "equitable and realistic" method for allocating distribution Mains costs, and provided the following analysis:

> Based upon the record evidence, this Commission concludes that the OUCC's cost-of-service study is most reflective of cost causation and possesses a high degree of objectivity upon which the Commission may place reliance in establishing the rates and charges in this proceeding.
>
> While we do not doubt that distribution Mains must be constructed with peak demand in mind, distributions Mains do not only serve customers on peak demand days. Therefore, a measure of the costs of distribution Mains must be allocated to customers based on their usage that takes place on non-peak days. For example, a customer that does not take service at all on the peak demand day-and therefore contributes nothing to peak demand requirements of distribution Mains-but receives service through distribution Mains at other times should be responsible for some portion of distribution main costs
>
> The OUCC's approach is much more equitable and realistic. Rather than allocating distribution main costs exclusively based on either peak demand day or average annual consumption, the OUCC used a compromise approach that allocated these costs based on both. Under the OUCC's cost of service study, 80% of distribution main costs are allocated based on average demand. (Public's Ex. No. 6 at 13.) In this way, the OUCC's approach allocates part of distribution main costs to customers who receive service through

> distribution Mains throughout the year but who may not receive much or any service on the peak demand day
>
> For the reasons set forth above, we find the OUCC's cost of service study most accurately reflects the manner in which distribution main costs are actually incurred. See, In Re Citizens Gas & Coke Utility, IURC Cause No. 39066, at 31 (Nov. 1, 1999). We therefore adopt the OUCC's cost of service study to implement the rates increase approved in this Cause.

In re Citizens Gas & Coke Utility, IURC Cause No. 42767, at 74-75 (Oct.19, 2006).

The Illinois Commerce Commission ("ICC") has accepted the Peak & Average method for allocating transmission and distribution costs in the natural gas industry. The ICC explained the reasoning behind utilizing a Peak & Average methodology in their decision as follows:

> Generally, [Central Illinois Public Service Company or "CIPS"] and [Union Electric Company or "UE"] gas transmission and distribution facilities exist because there is a daily need for such facilities. Regardless of when CIPS and UE experience their respective peak and the level of the peak, customers depend on the continued operation of the Ameren gas transmission and distribution systems to meet their daily needs. On the day that the peak does occur. Ameren's own Mr. Carls testifies that CIPS' and UE's respective systems are built to accommodate the system peak without regard to each class' peak. In light of the nature in which the transmission and distribution systems are used and because of the relatively declining cost of increasing capacity, peak demand is not the appropriate emphasis in allocating demand costs…As the Commission concluded in Docket 94-0040, a utility cannot justify its transmission and distribution investment on demands for a single day. The allocation method that properly weights peak demand is the [Average & Peak or "A&P"] method, the same method that the Commission adopted in CIPS' and UE's last gas rate cases. The A&P method properly emphasizes the average component to reflect the role of year-round demands in shaping transmission and distribution investments.

Central Ill. Pub. Service Co. Proposed General Increase in Natural Gas Rates, et al., 2003 Ill. PUC Lexis 824, 231-232 (2003).

Q. IS MS. HEPPENSTALL'S EXCLUSION OF INTERRUPTIBLE CUSTOMERS FROM AN ALLOCATION OF PEAK (EXCESS) DEMAND CAPACITY COSTS REASONABLE?

A. No. Interruptible customers benefit from the use of UGI Gas' peak demand component of Mains when not required to meet the requirements of firm customers on a design day. As indicated previously, UGI Gas' design day has a probability of occurrence once every 30 years. Therefore, it would be reasonable to assign a portion of peak demand capacity costs to interruptible customers. At a minimum, it would be reasonable, to assign peak demand costs to interruptible customers based on average daily usage. This would be consistent with the current practice of the FERC which designs rates for interruptible service based on a 100 percent load factor basis. That is, rates for interruptible service are designed assuming that the peak demand of an interruptible customer is equal to the customer's average daily usage. Under my recommendation, interruptible customers would be assigned peak demand costs based on a demand of 39,847 Dth. On the peak day during the winter of 2020-2021, interruptible customer usage was 156,500 Dth.

Q. DO YOU HAVE OTHER CONCERNS WITH UGI GAS' COST OF SERVICE STUDY?

A. Yes. I also have concerns with the Company's allocation of manufactured gas plant remediation costs, forfeited discounts, and reconnection fees.

Q. PLEASE EXPLAIN YOUR CONCERN WITH THE COMPANY'S ALLOCATION OF MANUFACTURED GAS PLANT REMEDIATION COSTS.

A. These expenses relate to site remediation of former manufactured gas plant sites. These plants were in operation during the period 1851-1955. Manufactured gas plant remediation costs are indicated in Accounts 740-742, 923, and 930 in the Company's cost of service study. The costs in Accounts 740-742 are allocated based in Factor 1 in the Company's cost of service study. Factor 1 allocates costs to customer class based on PGC sales volumes. The costs in Accounts 923 and 930 are allocated based on Factor 12 which allocates costs to customer class based on the overall allocation of operations and maintenance expenses. It is unreasonable to allocate the costs in Accounts 740-742 solely to current sales customers. It is unlikely that any of UGI Gas' current sales customers caused these costs to be incurred. Since these costs cannot be directly assigned to current customers, I recommend that they be allocated consistent with the allocation of the manufactured gas plant remediation costs in Accounts 923 and 930.

Q. PLEASE EXPLAIN YOUR CONCERN WITH THE COMPANY'S ALLOCATION OF FORFEITED DISCOUNTS.

A. Forfeited discounts have been assigned to each class based on Factor 20, which allocates costs based on an analysis of penalty revenues by class. I recommend that forfeited discounts be allocated based on actual forfeited discounts for the most recent 12 month period available (12-months ended January 2022, per Attachment OCA-I-18).

Q. PLEASE EXPLAIN YOUR CONCERN WITH THE COMPANY'S ALLOCATION OF RECONNECTION FEES?

A. The Company's cost of service study includes a separate line item for Reconnection Charges. However, there are no reconnection fees reflected on this line item in the Company's study. In the Company's study, reconnection fees totaling $580,00 have been included the Other Miscellaneous Revenue line item and allocated to customer class based on Factor 16, which provides for an allocation based on the overall allocated cost of service. (1&E-RS-24). I recommend that reconnection fees be removed from the Other Miscellaneous Revenue line item and be included in the Reconnection Charges line item and allocated based on actual reconnection fees for the most recent 12-month period available (12-month ended January 2022, per Attachment OCA-I-42).

Q. ARE THERE OTHER CHANGES THAT SHOULD BE MADE TO THE COMPANY'S COST OF SERVICE STUDY?

A. Yes. In the response to OCA-I-24, the Company indicated that there was an error in the allocation of the costs in Account 874 in its initially filed study. This error should be corrected.

Q. HAVE YOU PREPARED A COST OF SERVICE STUDY FOR THE UGI GAS SYSTEM THAT ADDRESSES YOUR CONCERNS WITH THE COMPANY'S STUDY?

A. Yes. Schedule JDM-1 presents the results of a cost of service study that I have performed for the UGI Gas system under present rates. My study is modeled after the Company's study but reflects the allocation of Mains utilizing the Peak & Average method. By allocating 50 percent of Mains investment costs on the basis of average demand in this study, I, as UGI Gas attempted to, have recognized the critical fact that UGI Gas' existence as a viable business entity relies upon, and thus, its distribution Mains investment costs are caused by, end-user annual gas requirements. I have also recognized that some additional costs are incurred to install Mains that can flow peak demand requirements in excess of average requirements by allocating a 50 percent portion of Mains investment costs on the basis of peak demands. This includes an allocation of peak demand costs to interruptible customers. Allocating 50 percent of UGI Gas' Mains costs based on peak demands results in a conservative recognition of volumetric cost responsibility, for the reasons previously discussed.

For the reasons previously discussed, my study also revised the allocation of manufactured gas plant remediation costs, forfeited discounts, and reconnection fees. These changes to UGI Gas' cost of service study correct significant misallocations of costs of UGI Gas' total cost of service and produce a cost study that is consistent with the principle that costs should be allocated to the service units that cause the costs to be incurred. I have also corrected the error in the allocation of costs in Account 874.

Q. HOW DO THE RESULTS OF YOUR RECOMMENDED PEAK & AVERAGE COST OF SERVICE STUDY COMPARE TO THE RESULTS OF UGI GAS' A&E STUDY?

A. Table 5 below compares the results of UGI Gas' and the OCA's cost of service studies at present rates.

Table 5. Combined Class Cost of Service and Rate of Return Present Rates

	Company			OCA Study		
	Cost of	Rate of Return		Cost of	Rate of Return	
Class	**Service**	**Percent**	**Unitized**	**Service**	**Percent**	**Unitized**
Residential (R)	$471,011,760	4.33%	0.70	$459,777,045	4.70%	0.77
Non-Residential (N)	$146,888,226	7.28%	1.18	$138,643,184	8.15%	1.33
Delivery Service (DS)	$32,808,421	8.61%	1.40	$32,985,303	8.52%	1.39
Large Firm Delivery Service (LFD)	$41,387,804	9.44%	1.54	$50,480,154	6.36%	1.04
Extended Large Firm Delivery Service (XD)	$28,012,485	14.01%	2.28	$30,405,440	12.32%	2.01
Interruptible (IT)	$17,906,171	13.46%	2.19	$25,712.852	7.11%	1.16
Overall	**$738,014,867**	**6.14%**	**1.00**	**$738,003.977**	**6.14%**	**1.00**

III. CLASS REVENUE REQUIREMENTS

Q. PLEASE DESCRIBE HOW UGI GAS IS PROPOSING TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG ITS CUSTOMER CLASSES IN THIS PROCEEDING.

A. UGI Gas claims it is proposing to move each rate class toward the cost of service indicated by its study. UGI Gas' proposed revenue distribution is presented in Table 6.

Table 6. Company Proposed Revenue Distribution

Class	Present Rates	Proposed Rates	Increase	Percent
Residential (R)	$377,368,713	$445,483,863	$68,115,150	18.1%
Non-Residential (N)	$138,825,398	$153,278,225	$14,452,827	10.4%
Delivery Service (DS)	$33,778,394	$34,432,339	$653,945	1.9%
Large Firm Delivery Service (LFD)	$44,861,623	$46,392,850	$1,531,227	3.4%
Extended Large Firm Delivery Service (XD)	$36,697,802	$35,735,967	($961,835)	-2.6%
Interruptible (IT)	$24,012,357	$22,963,170	($1,049,187)	-4.4%
Total	**$655,544,286**	**$738,286,415**	**$82,742,129**	**12.6%**

Q. WHAT ARE SOME OF THE PRINCIPLES OF A SOUND REVENUE ALLOCATION?

A. A sound revenue allocation should:

- Utilize class cost of service study results as a guide;
- Provide stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers or the utility (gradualism);
- Yield the total revenue requirement;
- Provide for simplicity, certainty, convenience of payment, understandability, public acceptability and feasibility of application; and
- Reflect fairness in the apportionment of the total cost of service among the various customer classes.[2]

Q. IS UGI GAS' PROPOSED REVENUE ALLOCATION REASONABLE?

A. No. UGI Gas' proposed revenue distribution is based on its cost of service study, and as explained in the prior section of my testimony, UGI Gas' cost of service study violates the principle of allocating costs on the basis of cost-causality, and does not reasonably reflect the costs of providing service to the various customer classes. The

[2] *Principles of Public Utility Rates*, Second Edition, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen; Public Utility Reports, Inc., 1988, pages 383-384.

OCA's cost of service study, which corrects the flaws in UGI Gas' study, should be used as guide for the allocation of any increase authorized by the Commission in this proceeding

Although UGI Gas' revenue allocation is guided by its cost of service study results, the Company is not proposing to set rates based on the results indicated by its cost of service study, but has proposed a revenue allocation which reflects movement toward the indicated cost of service for each customer class. More specifically, as indicated in Table 4 of the direct testimony of UGI Gas witness Ms. Sherry A. Epler (Statement No. 8), the Company is proposing increases which move each customer class approximately 55 percent toward the system average rate of return. Overall, such an approach could generally be reasonable if that cost of service study provided a reasonable indication of the cost of service for each class. A revenue allocation based on the OCA's cost of service study which moves each customer class toward the system average rate of return based on UGI Gas' proposed revenue requirement is presented in Table 7. Table 8 identifies the movement toward the cost of service for each customer class.

Table 7. OCA Proposed Cost of Service Study Revenue Distribution

Class	**Present Rates**	**Proposed Rates**	**Increase**	**Percent**
Residential (R)	$377,368,713	$437,650,632	$60,281,919	16.0%
Non-Residential (N)	$138,825,398	$151,804,131	$12,978.733	9.3%
Delivery Service (DS)	$33,778,394	$35,906,433	$2,128,040	6.3%
Large Firm Delivery Service (LFD)	$44,861,623	$50,514,565	$5,652,942	12.6%
Extended Large Firm Delivery Service (XD)	$36,697,802	$36,697,801	$0	0.0%
Interruptible (IT)	$24,012,357	$25,712,852	$1,700,496	7.1%
Total	**$655,544,286**	**$738,286,415**	**$82,742,129**	**12.6%**

Table 8. Unitized Rates of Return

Class	Present Rates	Proposed Rates
Residential (R)	0.77	0.88
Non-Residential (N)	1.33	1.18
Delivery Service (DS)	1.39	1.19
Large Firm Delivery Service (LFD)	1.04	1.00
Extended Large Firm Delivery Service (XD)	2.01	1.51
Interruptible (IT)	1.16	1.00
Total	**1.00**	**1.00**

Q. HOW DID YOU DEVELOP YOUR PROPOSED REVENUE ALLOCATION?

A. For Rate XD, the Company has proposed a rate decrease. I don't believe it is appropriate for a customer class to receive a rate decrease when overall, rates are increasing. Therefore, I recommend no change to the percent rates of Rate XD customers. The Company has also proposed a rate decrease for Interruptible Service customers. Under my cost of service study, Interruptible Service customers are contributing revenues that are less than the indicated cost of service. I have proposed a rate increase for Interruptible Service customers which increase their revenue contribution to the indicated cost of service. I have also proposed a rate increase for Rate LFD sufficient to increase their revenues to the cost of service indicated by my cost of service study. For Rate DS, I have proposed an increase equal to over half the system average increase. This moves the rate of return for Rate DS 50% toward the indicated cost of service. I have reduced the increase proposed by the Company for Rate N by an amount equal to the additional revenues I have assigned to Rate DS. This moves the rate of return for Rate N approximately 50% toward the indicated cost of service. Finally, I have proposed an increase for Rate R to account for the remaining revenue deficiency. This moves the rate of return for Rate R 50% toward the indicated cost of service.

Q. IF THE COMMISSION AUTHORIZES AN INCREASE FOR UGI GAS WHICH IS LESS THAN ITS REQUESTED INCREASE, HOW DO YOU RECOMMEND YOUR REVENUE ALLOCATION BE ADJUSTED TO ACCOUNT FOR THE LESS THAN REQUEST INCREASE?

A. As explained in the Direct Testimony of OCA witness Dante Mugrace (OCA Statement 1), the OCA has found that UGI Gas has a revenue sufficiency of $38.7 million, and that no increase in the Company's current rates is warranted. If the Commission determines that an increase in UGI Gas's current rates is appropriate, but that increase is less than the Company's requested increase of $82.7 million, I recommend a proportionate scale-back of my revenue distribution to reflect the increase authorized by the Commission.

IV. RATE DESIGN

Q. PLEASE DESCRIBE UGI GAS' CURRENT AND PROPOSED RESIDENTIAL RATES.

A. Residential customers are currently assessed a monthly customer charge of $14.60 and a volumetric distribution charge of $4.1104 per Mcf. UGI Gas is proposing to increase the monthly Residential customer charge to $19.95, or 37 percent, and increase the volumetric distribution charge to $4.9996 per Mcf, or 22 percent.

Q. SHOULD UGI GAS' PROPOSED INCREASE IN THE RESIDENTIAL CUSTOMER CHARGE BE APPROVED?

A. No, it should not, for several reasons. First, UGI Gas' proposed Residential customer charge proposal is out of line with the Residential customer charges of other NGDCs in the Commonwealth. Second, UGI Gas' proposed Residential customer charge violates the principle of gradualism. Finally, a high fixed monthly customer charge is inconsistent with the Commission's general goal of fostering energy conservation. I would note that OCA witness Mr. Roger Colton is also addressing UGI Gas' proposed Residential customer charge and has found that the proposed charge would have a disproportionately negative impact on low-income and low-use customers.

Q. HOW DOES UGI GAS' PROPOSED RESIDENTIAL CUSTOMER CHARGE COMPARE WITH THE MONTHLY RESIDENTIAL CUSTOMER CHARGES OF OTHER NGDCS IN THE COMMONWEALTH?

A. Table 9 provides a comparison of UGI Gas' Residential customer charge proposal with the customer charges of other Pennsylvania NGDCs. If adopted, UGI Gas' proposed monthly Residential customer charge of $19.95 would be significantly higher than that of any other NGDC in the Commonwealth.

Table 9. Comparison of Residential Customer Charges for Pennsylvania NGDCs

UGI Gas (proposed)	**$19.95**
Columbia Gas of Pennsylvania	$16.75
UGI Gas (current)	$14.60
Peoples Gas	$15.75
Philadelphia Gas Works	$14.90
Peoples Natural Gas	$14.50
PECO Energy Company	$13.63
National Fuel Gas Company	$12.00

Q. PLEASE EXPLAIN YOUR COMMENT THAT UGI GAS' RESIDENTIAL CUSTOMER CHARGE PROPOSAL VIOLATES THE PRINCIPLE OF GRADUALISM.

A. Gradualism is an important factor in developing a sound rate design and refers to stability and predictability in rates with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity. In short, gradualism refers to the avoidance of rate shock. UGI Gas' Residential customer charge proposal represents an increase of 37 percent in that rate. Such a significant increase should be avoided.

Q. WHY IS A HIGH FIXED MONTHLY CUSTOMER CHARGE INCONSISTENT WITH THE COMMISSION'S GENERAL GOAL OF FOSTERING ENERGY CONSERVATION?

A. The more revenue that is collected through the fixed monthly charge, the lower the volumetric charge. The higher the volumetric charge, the greater the incentive is to lower usage. In the UGI Gas' base rate proceeding in Docket No. R-2018-3006814, UGI Gas proposed a consolidated natural gas Energy Efficiency and Conservation

("EE&C") Plan to reduce ratepayers' natural gas bills, and increase comfort levels. The EE&C Plan was approved by the Commission. Higher customer charges may counter the EE&C Plan's effectiveness, as it limits the amount of potential bill savings through the reduction of variable charges, which may in turn, discourage ratepayers from implementing energy conservation measures.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE RESIDENTIAL CUSTOMER CHARGE THAT SHOULD BE ESTABLISHED IN THIS PROCEEDING?

A. Based on UGI Gas' requested increase, a Residential customer charge of $16.00 would be reasonable. A Residential customer charge of $16.00 would provide for consistency with the customer charges of other Pennsylvania NGDCs, and better promote the Commission's energy conservation goals. To the extent the Commission authorizes an increase that is less than the Company's requested increase, I recommend that the $16.00 charge be proportionately scaled-back to reflect the reduction in UGI Gas' requested increase. This would provide for a Residential customer charge that is consistent with the charges of other Pennsylvania NGDCs, provide for gradualism, and better promote energy conservation than the charge proposed by the Company.

V. <u>RATES NNS AND MBS</u>

Q. PLEASE DESCRIBE THE SERVICE PROVIDED BY UGI GAS' CURRENT RATE DISTRICTS UNDER RATE NO-NOTICE SERVICE.

A. Transportation customers served under Rate Schedules DS, LFD, XD, and IS are required to use their best efforts to balance deliveries on their behalf with their usage. On a daily basis, transportation customers are allowed imbalance tolerances which if exceeded, will result in the assessment of Daily Balancing Charges. The current daily imbalance tolerance is +/- 4.5 percent. The Daily Balancing Charges assessed for exceeding the daily imbalance tolerance vary depending on whether the imbalance occurs on a Critical Day or Non-Critical Day.[3]

Under Rate NNS, the Company either forwards or banks supplies to customers on a daily basis in amounts necessary to balance the customers' daily deliveries with daily consumption. In essence, Rate NNS increases the daily imbalance tolerance available to transportation customers. Customers elect the amount of NNS they wish to purchase (No-Notice Allowance or "NNA"). Customers may elect an NNA in an amount no less than the daily imbalance tolerance applicable to the maximum firm daily contract requirements ("DFR") to 100 percent of their DFR. Therefore, customers can elect an NNA of between 4.5 percent and 100 percent of their DFR. NNA revenues are currently credited to PGC customers.

Q. WHAT IS UGI GAS PROPOSING WITH RESPECT TO RATE NNS IN THIS PROCEEDING?

A. The current charge for Rate NNS is $0.4880 per Mcf/day of elected NNA. UGI Gas is proposing a charge of $0.1860 per Mcf/day of elected NNA based on what the Company claims is the cost of interstate storage service that can be utilized for balancing excess or shortfall requirements on the Company's system. Revenues received for Rate NNS will continue to be credited to PGC rates.

Q. IS THE PROPOSED CHARGE FOR RATE NNS REASONABLE?

A. The proposed Rate NNS charge is not reasonable. UGI Gas' interstate pipeline storage resources are the primary assets used by the Company to provide service under Rate NNS. The charges incurred by the Company for these storage services include fixed daily deliverability and seasonal capacity demand charges; variable storage

[3] Critical Days are days determined by the Company in its sole desecration, when variations in supply or demand could jeopardize the safety or reliability of service.

transportation-related fuel and commodity charges; and variable storage injection, withdrawal, and fuel charges. As shown on UGI Gas Exhibit SAE-8, the proposed Rate NNS charge is based on a storage trip cost of $0.1330 per Mcf .[4] The storage trip costs only include the variable costs associated with providing service under Rate NNS. PGC and non-Choice transportation customers are currently responsible for all of the demand charges associated with the interstate pipeline storage resources utilized to provide Rate NNS, and under UGI Gas' Rate NNS rate design, receive no contribution for the demand charges associated with the storage resources utilized to provide service under Rate NNS. This is unreasonable. PGC and non-Choice transportation customers should receive a contribution toward the fixed costs associated with the storage assets utilized to provide service under Rate NNS. I recommend that the storage trip cost be adjusted to include the demand charges associated with providing service under Rate NNS on a 100 percent load factor basis. This would be consistent with the current practices of the FERC which design rates for interruptible service based on a 100 percent load factor basis. As shown in Schedule JDM-2, inclusion of storage demand charges on a 100 percent load factor basis in calculating the storage trip cost would increase the storage trip cost to $1.425 per Mcf, and would increase the charge for Rate NNS service to $1.9960 per Mcf/day of elected NNA.

Q. PLEASE DESCRIBE THE SERVICE PROVIDED BY UGI GAS UNDER RATE MBS ("MONTHLY BALANCING SERVICE").

A. In addition to imposing daily imbalance requirements on transportation customers served under Rates DS, LFD, XD, and IS, monthly imbalance requirements are imposed. Usage in excess of deliveries of up to 5 percent (delivery shortfall) on a monthly basis are sold to a transportation customer or cashed-out, at a price reflective

[4] The storage trip cost reflects the variable charges incurred to inject and withdraw 1 Mcf of gas.

of a market price of gas in each former Rate District. Deliveries in excess of usage (excess deliveries) of up to 5 percent in a month are purchased by the Company from transportation customers, or cashed-out, at a price reflective of a market price. For delivery shortfalls in excess of 5 percent, multipliers are applied to the cash-out price which increases the price depending on the magnitude of the delivery shortfall. For excess deliveries in excess of 5 percent, multipliers are applied to the cash-out price which decreases the price depending on the magnitude of the excess delivery. Rate MBS is a monthly balancing service offered by the Company that allows transportation imbalances of up to 10 percent for the month, an increase of 5 percent, to be carried forward in the customer's MBS account for delivery of excess deliveries, or receipt of shortfalls, in subsequent months. Like the charges under Rate NNS, the charges collected under Rate MBS are currently credited to PGC customers.

Q. WHAT IS UGI GAS PROPOSING WITH RESPECT TO RATE MBS IN THIS PROCEEDING?

A. The charges applicable under Rate MBS currently vary by customer class. The current and proposed charges for service under Rate MBS are summarized in Table 10.

Table 10. Summary of Current and Proposed Charges under Rate MBS

Class	Current	Proposed
DS/IS	$0.0277	$0.0437
LFD	$0.0160	$0.0263
XD	$0.0165	$0.0221

Q. ARE THE PROPOSED CHARGES FOR SERVICE UNDER RATE MBS REASONABLE?

A. The proposed Rate MBS charges are not reasonable. As shown on UGI Gas Exhibit SAE-9, the proposed Rate MBS charges are based on an anticipated average transportation customer monthly imbalance of 2.5737 percent. Rate MBS provides for an additional monthly imbalance tolerance of 5 percent.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE DESIGN OF RATES FOR SERVICE UNDER RATE MBS?

A. I recommend that Rate MBS be designed based on a transportation customer monthly imbalance of to 5 percent to reflect the additional 5 percent monthly imbalance tolerance provided under Rate MBS. The charges for service under Rate MBS that reflect my recommended adjustment are developed and presented on Schedule JDM-3.

VI. <u>CAPACITY ASSIGNMENT</u>

Q. DOES THE COMPANY CURRENTLY RESERVE INTERSTATE PIPELINE CAPACITY TO MEET THE REQUIREMENTS OF ITS NON-CHOICE TRANSPORTATION CUSTOMERS?

A. Yes. UGI Gas currently maintains interstate pipeline capacity which it releases, or assigns, to non-Choice Transportation customers (Rates DS, LFD, and XD). For Rate DS customers, or their natural gas supplier, are assigned interstate pipeline firm transportation capacity based on the weighted average cost of the demand associated with the capacity reserved by the Company, inclusive of delivered supply services ("WACOD"). Per the settlement approved in Docket Nos. R-2018-3006814, also included in the WACOD calculation are 100 percent of the demand charges for peaking services. Rate LFD customers are similarly assessed a WACOD for assigned capacity with the exception that, pursuant to the settlement approved in Docket No. R-2018-3006814, the WACOD calculation includes 50 percent of the demand charges associated with peaking services. In the former South Rate District, Rate XD customers are assigned Columbia Gas Transmission ("TCO") firm transportation ("FT") pipeline capacity, and are assessed the same rates UGI Gas is charged for that capacity by TCO. UGI Gas is proposing to maintain its current capacity assignment procedures.

Q. IS UGI GAS' PROPOSAL TO CONTINUE THE EXISTING PROCEDURES FOR THE RELEASE OF CAPACITY TO RATE XD CUSTOMERS IN THE FORMER SOUTH RATE DISTRICT REASONABLE?

A. No. The TCO capacity released to Rate XD customers in the former South District is among the Company's lowest cost capacity resources. Rate XD customers should not have preferential access to the Company's lowest cost capacity resources while PGC and Choice transportation customers are held responsible for the costs associated with the Company's higher cost capacity resources. For example, the current monthly demand charge for TCO FT capacity is $9.59 Dth per day, while UGI Gas' WACOD for FT capacity is $14.90 and the WACOD of peaking capacity is $14.94 Dth (Response to OCA-I-43). Capacity should be released to Rate XD customers based on the WACOD calculation applicable for LFD customers. It is my understanding that Rate XD customers currently maintain service contracts that specifically provide for the assignment of TCO capacity. Therefore, Rate XD customers should continue to be assigned TCO capacity until their current service contracts expire, at which time Rate XD customers should be assessed the same charges for released capacity that are assessed to Rate LFD customers.

VII. WEATHER NORMALIZATION ADJUSTMENT MECHANISM

Q. PLEASE DESCRIBE THE WEATHER NORMALIZATION ADJUSTMENT MECHANISM PROPOSED BY UGI GAS.

A. The WNA proposed by UGI would apply to Residential customers receiving service under Rates R and RT, and Non-Residential customers receiving service under Rates N and NT. Under the WNA, the amount billed to each customer will be adjusted to offset what the Company claims is the usage impact caused by variations between actual heating degree days ("HDD") and normal HDD. Actual usage on each customer's bill will be utilized to calculate the WNA. The WNA would apply during the months of October through May.

Q. PLEASE EXPLAIN HOW THE WNA WILL BE CALCULATED FOR EACH CUSTOMER.

A. Based on three-years of usage for each customer during the period June 21 through September 20, the Company will determine each customer's Baseload Month Commodity usage (BLMC), or non-temperature sensitive usage. For each month during the billing periods for October through May, normal HDD will be divided by actual HDD to determine the percentage variance from normal weather. A customer's Actual Monthly Commodity usage (AMC) will then be reduced by the customer's BLMC to determine the customer's weather sensitive usage, and weather sensitive usage will then be multiplied by the percentage variance from normal weather to determine weather-normalized usage. Each customer will then be billed or credited for the variance between weather-normalized and actual usage through the proposed WNA mechanism.

Q. HAS THE COMMISSION ADOPTED A STATEMENT OF POLICY CONCERNING ALTERNATIVE RATE MAKING MECHANISMS SUCH THE WNA MECHANISM PROPOSED BY UGI GAS?

A. Yes. In an Order entered July 18, 2019, in Docket No. M-2015-2518883, the Commission set forth its Statement of Policy with respect to alternative ratemaking methodologies. In its Statement of Policy, the Commission identified 14 factors it would consider in evaluating an alternative ratemaking mechanism. The Statement of Policy required a utility proposing an alternative ratemaking mechanism to explain how each of these 14 factors impact the rates of each customer class.

Q. DOES THE COMPANY ADDRESS THESE 14 FACTORS IN ITS DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, the 14 factors are identified in the Direct Testimony of Mr. John D. Taylor (Statement No. 11). Mr. Taylor also addresses how the WNA mechanism allegedly aligns with the Commission's Statement of Policy on alternative ratemaking.

Q. WHAT ARE THE 14 FACTORS FOR CONSIDERATION IDENTIFIED IN THE COMMISSION'S STATEMENT OF POLICY ON ALTERNATIVE RATEMAKING, WHAT IS MR. TAYLOR'S RESPONSE TO THE 14 FACTORS, AND WHAT IS YOUR RESPONSE TO MR. TAYLOR'S CLAIMS?

A. Each rate consideration identified in the Statement of Policy is listed below along with the Company's claimed relevant effect of the WNA Mechanism on each rate consideration. Also identified below is my response to the Company's claim:

Consideration 1	Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.
	<u>UGI GAS:</u> UGI Gas' proposed WNA is designed to recover distribution revenues needed to satisfy the cost-of-service requirement determined in this proceeding, while mitigating the variance between actual and projected distribution revenues due to weather. UGI Gas recovers a significant portion of fixed costs through volumetric rates. These fixed costs do not vary with the amount of gas delivered to

customers and are composed of fixed operation and maintenance ("O&M") expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. In the absence of Straight Fixed Variable ("SFV") rate design; where all fixed costs are recovered in a fixed monthly charge, a WNA mechanism will better align distribution revenues with cost causation principles; appropriately accounting for variation in usage due to weather.

<u>OCA</u>: The Company's response does not indicate how the WNA mechanism aligns revenues with cost causation as to fixed and variable costs. In addition, as subsequently discussed in my testimony, the WNA does not appropriately account for variations in customer usage due to weather and is biased in the Company's favor during colder-than-normal billing periods.

Consideration 2 — Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

<u>UGI GAS:</u> UGI Gas' WNA proposal has no identifiable impact on capacity utilization.

<u>OCA</u>: I agree with the Company's response.

Consideration 3 — Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

<u>UGI GAS:</u> Customer specific usage factors corresponding to their individual demand (the BLMC for each customer) is continually updated and reflects the level of demand associated with the customer's anticipated consumption levels.

<u>OCA</u>: The BLMC is a customer's baseload demand and, therefore, only reflects a small portion of a customer's demand during the October through May proposed effective period of the WNA mechanism. Therefore, the Company's response is incomplete.

Consideration 4 — How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.

	<u>UGI GAS</u>: Since the proposed WNA mechanism is applying rates which are based upon the specific revenue allocation and rate design approved by the Commission, it will mitigate the potential for interclass or intraclass cost shifting related to weather driven usage variances from those weather assumptions used in establishing rates.
	<u>OCA</u>: The WNA does not result in interclass or intraclass cost shifting.
Consideration 5	Please explain how the WNA limits or eliminates disincentives for the promotion of efficiency programs.
	<u>UGI GAS</u>: The proposed WNA only addresses variations due to weather. The WNA does not negatively impact energy efficiency programs. Moreover, UGI Gas maintains a robust Energy Efficiency & Conservation ("EE&C") program, which it has voluntarily implemented for its customers and will use to continue promoting energy efficiency measures.
	<u>OCA</u>: The WNA does not limit or eliminate incentives for the promotion of efficiency programs.
Consideration 6	Please explain how the WNA impacts customer incentives to employ efficiency measures and distributed energy resources.
	<u>UGI GAS</u>: Customers will continue to have an incentive to employ energy efficiency measures and distributed energy resources because a reduction in usage still reduces their overall bill and the portion of their bill that is subject to the WNA mechanism.
	<u>OCA</u>: As discussed by OCA witness Mr. Roger Colton, the WNA will disproportionately and adversely affect low-income customers.
Consideration 7	Please explain how the WNA impacts low-income customers and support consumer assistance programs.
	<u>UGI GAS</u>: Under the WNA mechanism, certain customers enrolled in the Customer Assistance Program ("CAP") who pay an "average bill" amount will see lower bill variability for distribution costs during colder than average periods, while CAP customers who are paying on a percent-of-income basis will see little to no impact.
	<u>OCA</u>: As discussed by OCA witness Mr. Roger Colton, the WNA will disproportionately and adversely affect low-

income customers. In addition, as subsequently explained, the WNA will not appropriately adjust a customer's bill to reflect normalized usage during colder-than-normal billing periods.

Consideration 8	Please explain how the WNA impacts customer rate stability principles.
	UGI GAS: The WNA mechanism will provide customers more stable annual bills and directly mitigate volatility in their monthly costs.
	OCA: As discussed by OCA witness Mr. Roger Colton, budget billing would better protect Residential customers from bill volatility due to weather volatility. In addition, as subsequently explained, the WNA will not appropriately adjust a customer's bill to reflect normalized usage during colder-than-normal billing periods.
Consideration 9	Please explain how weather impacts utility revenue under the WNA.
	UGI GAS: The proposed WNA adjusts a customer's bill due to variations from normal weather and is employed for usage during the heating season months (October – May). It only applies to certain of the Company's customer classes (Rates R, RT, N and NT) and it does not ensure the utility will recover 100% of its authorized distribution revenues, but it does reduce the amount of weather-related variation in both customer bills and associated utility distribution revenues.
	OCA: I generally agree with the Company's response. However, as subsequently explained, the WNA will not appropriately adjust a customer's bill to reflect normalized usage during colder-than-normal billing periods.
Consideration 10	Please explain how the WNA impacts the frequency of rate case filings and affects regulatory lag.
	UGI GAS: The WNA is not anticipated to impact the frequency of rate cases or have an impact on regulatory lag.
	OCA: A reduction to the frequency of rate case filings would be a benefit of an alternative ratemaking mechanism. The WNA does not provide this benefit.

Consideration 11	Please explain if the WNA interacts with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).
	UGI GAS: The Company's proposed WNA (appearing as Rider C – WNA in the Tariff) only applies to distribution related charges that are recovering the base distribution revenue requirement from applicable WNA customer classes for the heating season of October through May. Specifically, the billing for the Company's Riders, including Rider F – USP, Rider G – EE&C, and Rider B – PGC, will continue to be based on actual monthly usage.
	OCA: The WNA will not interact with other revenue sources.
Consideration 12	Please explain whether the WNA includes appropriate consumer protections.
	UGI GAS: The WNA mechanism will result in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates. UGI Gas will not recover additional distribution revenues due to colder than average temperatures that result in higher-than-normal usage from customers.
	OCA: The WNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony.
Consideration 13	Please explain whether the WNA is understandable to customers.
	UGI GAS: UGI Gas' WNA is not a new concept to the regulated utility industry. Similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. UGI Gas has proposed a WNA tariff that provides detailed information to the customer of how the mechanism works based on successful working versions found in the tariffs of other Pennsylvania natural gas distribution companies that have implemented a WNA tariff. Further, educational materials and customer service training will be developed upon approval of the mechanism, as well

as appropriate notice being provided to customers related to the WNA being approved pursuant to the Commission's alternative ratemaking notice requirements

<u>OCA</u>: UGI has not provided any evidence to indicate that the WNA will be understandable to customers.

Consideration 14 Please explain how the WNA will support improvements in utility reliability.

<u>UGI GAS</u>: UGI Gas' cost of service is inclusive of investments and costs to continue to enhance the safety and reliability of its system. The proposed WNA will help minimize the volatility of the recovery of these costs.

<u>OCA</u>: The WNA does not provide an incentive to increase the safety and reliability of the UGI Gas System.

Q. SHOULD THE WNA MECHANISM BE APPROVED BY THE COMMISSION?

A. No. The WNA mechanism should not be approved for the following reasons:

- The proposed WNA mechanism embodies a take-or-pay pricing policy.
- The proposed WNA mechanism inappropriately adjusts rates without considering other changes in total revenues and costs.
- The proposed WNA mechanism is biased to the Company's benefit during colder-than normal billing periods.
- UGI Gas has not demonstrated that its current system of rates and charges result in inadequate revenue stability, and does not decrease the frequency of rate case filings by UGI Gas.

Based on these concerns, the WNA mechanism should not be approved.

Q. DOES THE PROPOSED WNA MECHANISM EMBODY A TAKE-OR-PAY PRICING POLICY?

A. Yes. In the marketplace, consumers pay for the goods and services they receive. Under the proposed WNA mechanism, consumers would pay for distribution service they do and do not receive. No matter how much distribution service is actually purchased by

UGI Gas' Residential customers, ultimately, under the proposed WNA mechanism, those customers would pay for a normalized level of service whether they take delivery or not. This conversion of a volumetric rate into rates that yield a given revenue, regardless of the amount of service purchased, converts the Company's volumetric rate into a take-or-pay billing feature.

Q. PLEASE EXPLAIN HOW WNA COULD RESULT IN INAPPROPRIATE REVENUE ADJUSTMENTS.

A. The proposed WNA mechanism operates to adjust revenues, automatically, between rate cases, simply as a function of Rate R, RT, N, and NT distribution revenues being different from normalized revenues due to weather. There is no review of UGI Gas' costs. For example, an NGDC's O&M expenses would tend to increase as demand increase under colder-than-normal weather and tend to decline as demand decreases under warmer-than-normal weather. Under the WNA proposed by UGI Gas, and as explained by the Company, revenues billed to those rate classes subject to the WNA would be increased during warmer-than-normal billing periods from those that would be billed based on actual weather. Those billing increases would not be adjusted to reflect any decline in O&M expenses that may have occurred resulting in inappropriate revenue adjustments.

Q. YOU INDICATED THAT THE WNA IS BIASED TO THE COMPANY'S BENEFIT DURING COLDER-THAN-NORMAL BILLING PERIODS. PLEASE EXPLAIN THIS BIAS.

A. Under the WNA, actual usage is adjusted to reflect usage under normal temperatures as measured by HDD. The usage of customers per HDD increases as HDD increase. Therefore, during colder-than-normal billing periods, customer usage per HDD is higher than customer usage per HDD would be during a billing period with normal temperatures. Under the WNA, normalized customer usage is determined based on actual usage per HDD during the billing month. As a result, during a colder than normal billing period, normalized usage under the WNA is higher than it would be if normal weather were experienced, and the credit to a customer under the WNA for additional usage would be lower, which benefits the Company. Hypothetically, for example, let's say normal HDD for a month are 800 and under normal weather a customer is would use 18 Mcf, of which 2 Mcf is baseload usage (BLMC). For this customer, heat sensitive usage is .02 Mcf per HDD ((18 Mcf actual usage -2 Mcf BLMC usage)/800 HDD). Total normalized usage for this customer would be 18 Mcf and heat sensitive usage would be 16 Mcf. But, if a month is colder than normal, say for example, 1,000 HDD, usage per HDD goes up as it gets colder. Let's say that usage per HDD for this customer goes to .025 Mcf. In a month with 1,000 HDD, usage for this customer would be 27 Mcf ((.025 Mcf usage per HDD x 1,000 HDD) + 2 Mcf BLMC). That is, heat sensitive usage would be 25 Mcf and baseload usage would be 2 Mcf. Under the WNA, the 25 Mcf in heat sensitive usage would be multiplied by 80% (800 normal HDD/1000 actual HDD) which would be added to the BLMC indicating WNA adjusted usage of 22 Mcf ((80% x 25 Mcf) + 2Mcf BLMC). This is higher than normalized usage of 18 Mcf and thus results in a benefit to the Company and not the customer.

Q. HAS UGI GAS DEMONSTRATED THAT ITS CURRENT SYSTEM OF RATES AND CHARGES DO NOT PROVIDE FOR ADEQUATE REVENUE STABILITY?

A. No. UGI Gas' current system of rates and charges, which include fixed monthly customer charges, a Purchased Gas Adjustment mechanism, and a Distribution System Improvement Charge, provide for revenue stability, and UGI Gas has not demonstrated that this stability is inadequate.

Q. ARE THERE OTHER REASONS THAT THE WNA SHOULD NOT BE APPROVED AT THIS TIME?

A. Yes. The COVID-19 pandemic is another reason WNA mechanism should not be approved. There is a great deal of uncertainty concerning the impact of the pandemic on customer usage and unintended consequences could result. For example, under the WNA, the BLMC is based on a three-year average. The BLMC of Residential customers could have changed significantly as a result of the pandemic and customers could be assessed charges for these changes in usage. Alternative ratemaking mechanisms such as the WNA mechanism need to be accompanied by sufficient consumer protections.

Q. IF THE COMMISSION DISAGREES WITH YOUR RECOMMENDATION AND APPROVES THE WNA MECHANISM PROPOSED BY THE COMPANY, SHOULD THE MECHANISM BE MODIFIED?

A. Yes. Consistent with the WNA pilot of Columbia Gas of Pennsylvania, Inc., the Company's proposed WNA should be modified to include a 3 percent deadband so that the WNA is not applied if weather is less than 3 percent warmer or colder than normal. It is unreasonable to assume that weather and natural gas usage is abnormal if a particular day is only a few HDDs warmer or colder than normal. If a deadband is not adopted, the WNA would be applied if actual weather was only one HDD colder or warmer than normal. An HDD is determined by taking the average of daily high and low temperatures, and daily usage can vary due to factors other than temperature such as windspeed. In addition, HDD is not a precise measurement of the average daily temperature which should be utilized to determine temperature sensitive usage. There can be significant differences in the average daily temperature as measured by HDD, and a daily average temperature which is determined, for example, by averaging the temperatures observed each hour of the day. UGI Gas is proposing to separately calculate the WNA based on temperatures in each Delivery Region. For the South Delivery Region which is, the Company's largest Delivery Region, UGI Gas is proposing to average temperatures reported for five different weather stations to determine the WNA. Temperatures within a Delivery Region, and temperatures at the five different weather stations for the South Delivery Region can vary. Therefore, a 3 percent deadband should be adopted to help ensure that the assessment of the WNA is limited to changes in usage attributable to variations in temperature.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does at this time.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
	)	
v.	)	Docket No. R-2021-3030218
	)	
UGI UTILITIES, INC. – GAS DIVISION	)	

SCHEDULES ACCOMPANYING THE

DIRECT TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

April 20, 2022

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
UGI Gas, Maryland 21044

UGI UTILITIES, INC. - GAS DIVISION

DEVELOPMENT OF RATE OF RETURN BY SERVICE CLASSIFICATION UNDER PRESENT RATES

Item	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD-Firm	Interruptible
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1. Revenues From Tariff Sales and Transportation	$ 655,544,286	$ 377,368,713	$ 138,825,398	$ 33,778,394	$ 44,861,623	$ 36,697,802	$ 24,012,357
2. Other Revenues	10,286,468	6,227,639	2,571,585	423,202	529,571	310,372	224,099
3. Total Operating Revenues	665,830,754	383,596,352	141,396,983	34,201,596	45,391,194	37,008,174	24,236,456
4. Less: Operating Expenses	431,313,348	282,021,126	72,167,363	18,753,177	26,232,787	19,186,355	12,952,540
5. Return and Income Taxes	234,517,406	101,575,226	69,229,620	15,448,419	19,158,407	17,821,818	11,283,916
6. Less: Interest Expense	56,726,000	32,793,301	12,411,649	2,643,432	4,464,336	2,076,172	2,337,111
7. Taxable Income	177,791,406	68,781,925	56,817,971	12,804,987	14,694,071	15,745,646	8,946,805
8. Less: Income Taxes	39,835,701	15,412,433	12,731,490	2,868,170	3,290,429	3,529,443	2,003,736
9. Net Return (Ln 5 - Ln 8)	194,681,705	86,162,793	56,498,130	12,580,249	15,867,978	14,292,375	9,280,180
10. Original Cost Measure of Value (Factor 15.)	3,169,006,038	1,832,072,451	693,302,016	147,663,441	249,382,089	116,011,565	130,574,476
11. Rate of Return, Percent	6.14%	4.70%	8.15%	8.52%	6.36%	12.32%	7.11%
12. Relative Rate of Return	1.00	0.77	1.33	1.39	1.04	2.01	1.16

Schedule JDM-2

UGI Utilities, Inc. - Gas Division
No Notice Service (NNS) Rate Calculation

Notes:

1/ Storage Trip Cost ($/mcf) 1.4253

2/ Weekend Load Reduction Factor (%) 15.0%

WELF = Weekend Load Reduction Factor
WD = Weekday Day Use
WE = Weekend Day Use
AVERAGE = Average Daily Use

3/ EQ #1 **WD** **= (1/(1 - WELF)) * WE**
= (1/(1 - 0.15)) * WE
WD = 1.18 * WE

EQ #2 **AVERAGE = [(5 * WD) + (2 * WE)] / 7** — substitute EQ #1 into EQ #2 to remove variable WD
Step 1 AVERAGE = [5 * ((1/ (1 - WELF)) * WE)) + (2 * WE)] / 7
= [5 * (1/(1 - WELF)) + 2] * WE] / 7
= [5 * (1/(1 - 0.15)) + 2] * WE] / 7
7.90 * WE / 7
Step 2 WE = 0.89 * AVERAGE — solve Step 1 equation for WE

4/ EQ #3 **Wkly Imbalance = 5 x (WD - AVERAGE) + 2 (AVERAGE - WE)**
= (5 * WD) - (3 * AVERAGE) - (2 * WE) — substitute EQ #1 into EQ #3 to remove variable WD
= (5 * (1/(1-WELF) * WE) - (3 * AVERAGE) - (2 * WE)
= [(5 * (1/(1-WELF)) - 2) * WE] - (3 * AVERAGE)
= [(5 * (1/(1-0.15)) - 2) * WE] - (3 * AVERAGE)
3.90 * WE - (3 * AVERAGE) — substitute EQ# 2 step 2 into EQ #3 to remove variable WE
0.47 * AVERAGE

EQ #4 **Unit Cost Calculation ($/mcf)**
= [(Wkly Imbalance) / (7 * AVERAGE)] * STORAGE TRIP COST
= [(0.47 x Average) / (7 x AVERAGE)] x 0.133 — substitute EQ #3 for Wkly Imbalance
0.07 x 1.4253
0.0998

EQ #5 **Per Unit of Demand Calculation ($/mcf per month)**
= Unit Cost Demand x 20 days
= 0.0998 x 20
1.9960

Notes:

1/ Weighted average of storage trip costs based on SCQ of storages
2/ Aggregate load reduction for all non-Choice transportation customers electing NNS
Weekend Load Reduction factor percentage based on historical data for the period Nov 2020 through Oct 2021
3/ Assumes WD use approximately equal for all weekdays (work week)
Assumes WE use approximately equal for all weekend days
4/ Assumes levelized deliveries on all days

UGI Utilities, Inc. - Gas Division
Monthly Balancing Service (MBS) Rate Calculation

Notes:

1/	Average Capacity Charge for Storage ($/mcf)	1.2920	(A)
2/	Anticipated Average Monthly Imbalance %	5.0000%	(B)
3/	Load Factors & MBS Rate Calculation		

Rate	Load Factor	
DS	27.2%	(C)
LFD	56.1%	(C)
XD Firm	63.1%	(C)
Transportation System Average	55.4%	(D)

MBS Rate Formula
E = [(A / D) - ((A / D) * C)] * B

Rate	MBS Rate ($/mcf)	
DS	0.0849	(E)
LFD	0.0512	(E)
XD Firm	0.0430	(E)

1/ Weighted average of storage capacity and demand costs based on SCQ of storages
2/ Average monthly imbalance percentage includes all non-Choice transportation customers electing MBS
Average monthly imbalance percentage based on historical data for the period Nov 2020 through Oct 2021
3/ Load Factors based on FPFTY throughput and peak capacity for applicable customers by rate class

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts set forth in my Direct Testimony, OCA Statement 3, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 20, 2022
*327284

Signature: __/s/ Jerome D. Mierzwa________
Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3030218
UGI Utilities – Gas Division	:	

Direct Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement 4

April 20, 2022

Table of Contents

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a principal in the firm of Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving water/sewer, natural gas and electric utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Office of Consumer Advocate.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of New Hampshire, Maryland, Pennsylvania, Ohio, Michigan, Tennessee, Kansas, Wisconsin and Washington. My typical clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Illinois Office of Attorney General), federal agencies (e.g., the U.S. Department of Health and Human Services), community-based organizations (e.g., National Housing Trust, Natural Resources Defense Council, Advocacy Centre Tenants Ontario), and private utilities (e.g., Toledo Water, Entergy Services, Xcel Energy d/b/a Public Service of Colorado). In addition to state-specific and utility-specific work, I engage in national work throughout the United States. For example, in 2011, I worked with the U.S. Department of Health and Human Services (the federal LIHEAP office) to advance the review and utilization of the Home Energy Insecurity Scale as an outcomes measurement tool for the federal Low-Income Home Energy Assistance Program ("LIHEAP"). In 2007, I was part of a team that performed a multi-sponsor public/private national study of low-income energy assistance programs. In 2020, I completed a study of water affordability in twelve U.S. cities for the London-based newspaper, The Guardian. In 2021, I prepared a Water Affordability Plan for the City of Toledo (OH). A brief description of my professional background is provided in Appendix A.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained further training in both law and economics. I received my law degree in 1981 (University of Florida). I received my Master's Degree (regulatory economics) from the MacGregor School in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published three books and more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues. My most recent publication is a chapter in the book "Energy Justice: US and International Perspectives," published by Edward Elgar

Publishing in London. My chapter was titled "The equities of efficiency: distributing usage reduction dollars." It offers an objective definition of "equity" based on legal and economic doctrine.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PUC" or "Commission") on numerous occasions regarding utility issues affecting low-income customers and customer service. I have also testified in regulatory proceedings in more than 300 proceedings in 43 states and various Canadian provinces on a wide range of utility issues. A list of the states and provinces in which I have testified is listed in Appendix A.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. The purpose of my Direct Testimony is as follows.

- First, I examine the disproportionate harms that the proposed UGI Gas residential customer charge will impose on low-income customers of UGI Gas;
- Second, I examine the impact of the Company's proposed Weather Normalization Adjustment (WNA) on low-income customers;
- Third, I examine the appropriate steps for UGI Gas to take when it converts low-income customers from a non-gas fuel to natural gas service;
- Fourth, I examine the performance of UGI Gas in achieving specified universal service outcomes. I recommend that the Commission, rather than

reviewing the universal activities of UGI Gas (what the Company says it *does*), should instead review what UGI Gas *accomplishes*;

- Fifth, I examine the need to continue certain COVID-19 protections until at least UGI Gas files its next base rate case;
- Sixth, I examine the need to invest additional dollars in low-income energy efficiency in order to stabilize low-income bills in light of the harms imposed on low-income customers as a result of proposals UGI Gas advanced in this rate case;
- Seventh, I discuss the reason why I recommend deferring consideration of the proper inter-class allocation of universal service costs to a future rate case; and
- Finally, I examine the reasonableness of UGI Gas' request for an adder to its return on equity based on the Company's claims of exemplary management.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on the data and discussion presented below, I recommend as follows:

1. I recommend that the residential customer charge proposed by OCA witness Jerome Mierzwa be approved.

2. I recommend that the proposals of OCA witness Jerome Mierzwa regarding the Company's proposed WNA be adopted.

3. I recommend that UGI Gas be directed to screen customers who the Company assists in their conversion to natural gas in order to identify those converted customers as Confirmed Low-Income customers and to enroll those customers in CAP where appropriate.

    a. I further recommend that the Company add a new incremental component to its Low-Income Usage Reduction Program (LIURP) through which it will provide LIURP investments to Confirmed Low-Income customers as part of the process of converting those customers to natural gas

4. I recommend the Commission establish three measurable Outcome Objectives that UGI Gas should seek to accomplish with respect to CAP:

    a. **<u>Outcome Objective #1</u>**: UGI Gas should achieve a Confirmed Low-Income identification rate, as a percentage of estimated low-income customers, no less than the Confirmed Low-Income identification rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).

    b. **<u>Outcome Objective #2</u>**: UGI Gas should achieve a CAP participation rate, as a percentage of Confirmed Low-Income customers, no less than the CAP participation rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).

    c. **<u>Outcome Objective #3</u>**: UGI Gas should achieve a CAP default rate as a percentage of participants in the lowest poverty level range that is no less than the CAP default rate in that poverty level range for Pennsylvania gas utilities as a whole.

5. I recommend further that the Commission should determine that it will use these outcome performance metrics to review the adequacy of UGI Gas performance in future rate cases.

6. I recommend that the COVID responses that UGI had previously agreed to extend through the end of 2021 be continued until UGI Gas' next base rate case. In particular, I recommend:

    a. UGI commit to continuing to offer the extended payment plans as identified in the April 2021 Order in Docket M-2020-0319244;

    b. UGI reinstate its waiver of residential deposits for existing customers. The COVID-related payment difficulties of residential customers are not indicators of long-term payment risks. And the imposition of a cash security deposit remains an impediment to customers retiring the arrears that they have already incurred;

c. UGI reinstate its expanded hardship grant income eligibility, along with its expanded maximum hardship grant; and

d. UGI make an additional $1.0 million non-rate recoverable contribution to its hardship fund on an additional one-time basis.

7. I recommend that, to offset the harms imposed on Confirmed Low-Income customers by the relief UGI Gas seeks in this rate case, UGI Gas expand its LIURP spending by $1.425 million a year, sufficient to serve 231 additional Confirmed Low-Income customers per year. These additional LIURP jobs are in addition to the LIURP jobs that I recommend above be directed toward low-income households at the time they are converted from other fuels to natural gas.

8. I recommend that the consideration of the appropriate inter-class allocation of universal service costs be deferred to a future rate case to be considered once the economic crisis associated with the COVID-19 health pandemic has been reasonably resolved.

9. I recommend that the recommendation of OCA witness David Garrett should be adopted with respect to the UGI Gas request for an additional return on equity for exemplary management performance.

PART 1. The Impact of the Proposed UGI Gas Customer Charge on Low-Income Customers.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine how the proposed increase in the UGI Gas residential customer charge disproportionately and adversely affects low-income customers. UGI Gas proposes to increase its residential customer charge by 37%, from $14.60 per month to $19.95 per month. (UGI St. 8, at 20). As I will explain further in my testimony, this proposed increase would impose disproportionate harms on low-income customers.

Q. ARE LOW-INCOME CUSTOMERS PROTECTED AGAINST INCREASES IN THE CUSTOMER CHARGE BY THE UGI GAS CUSTOMER ASSISTANCE PROGRAM (CAP)?

A. No. UGI Gas has confirmed the low-income status of only a fraction of its low-income customers. In turn, the Company has enrolled only a fraction of its Confirmed Low-Income customers into CAP. In the past two years (2020, 2021), UGI Gas has confirmed the low-income status of only half of its estimated number of low-income customers. Most recently, UGI Gas had nearly 75,000 customers that were estimated to be low-income, but not identified as low-income on its system. In 2018, UGI Gas had confirmed the low-income status of only 40% of its low-income customers, leaving nearly 94,000 low-income customers unidentified as low-income. (OCA-II-17). In turn, UGI Gas has enrolled only a fraction of its Confirmed Low-Income customers into CAP. In 2021, fewer than 30% of the Company's Confirmed Low-Income customers were enrolled in CAP. Putting those two figures together, I find that in 2021 only 14% of the estimated low-income customer base of UGI Gas is enrolled in the Company's CAP.

Table 1. Estimated Low-Income Customers, Confirmed Low-Income Customers, CAP Participants (2018 – 2020) (OCA-II-15, OCA-II-17)

	Estimated LI	Confirmed LI	Pct Confirmed of Estimated LI	CAP Participants (December)	Pct CLI Participating in CAP	% Estimated LI Participating in CAP
2018	159,649	66,094	41%	18,282	28%	11%
2019	153,971	74,493	48%	23,451	31%	15%
2020	151,918	77,553	51%	24,023	31%	16%
2021	153,437	78,450	51%	22.025	28%	14%

This data provided in discovery is consistent with UGI Gas data reported in the Bureau of Consumer Services 2020 annual Report on Universal Service Programs and Collections

Performance.[1] BCS reports the same 2020 data for estimated low-income customers (151,918) and Confirmed Low-Income customers (77,553); it reports virtually the same number of CAP participants (24,236).

From this, we can deduce that at least 86% of UGI's estimated low-income customers are not paying a percentage of income-based CAP bill and, thus, are not insulated from the effects of the proposed increase in UGI's fixed monthly customer charge.

Q. DOES PARTICIPATION IN CAP, UNTO ITSELF, PROTECT LOW-INCOME CUSTOMERS FROM THE HARMS OF AN INCREASED CUSTOMER CHARGE?

A. No. CAP only protects low-income customers from the harms of an increased customer charge if they participate in the percentage of income-based CAP program offered by the Company. If a low-income customer instead participates in the CAP program where CAP bills are based on average bills, any increase in rates, particularly any increase in rates through the unavoidable fixed customer charge, will increase the average bill that must be paid by these CAP participants.

Not all CAP customers participate in the percentage of income part of the UGI Gas CAP. A sizable percentage of CAP participants instead participate in CAP under the average bill structure. According to UGI Gas, of the 20,601 CAP participants as of March 6, 2022, more than half (51%) (10,547) participate in the average bill CAP program.

[1] Available at https://www.puc.pa.gov/media/1709/2020-universal-service-report-final.pdf (last accessed April 16, 2022).

(CAUSE-PA-I-2). Customers participate in the average CAP program component if their budget billing amount is less than the percentage-of-income based payment.

Q. PLEASE SUMMARIZE THE EXTENT TO WHICH CAP PROTECTS LOW-INCOME CUSTOMERS.

A. UGI Gas has confirmed the low-income status of only half (51%) of its estimated number of low-income customers. UGI Gas has then enrolled only 28% of those Confirmed Low-Income customers into CAP (28% x 51% = 14%). Of those 14% of low-income customers who are enrolled in CAP, more than half (51%) are enrolled in a CAP program structure that bases the participant bills on an average bill rather than on a percentage of income. I conclude that a very small percentage of low-income customers (14% x 51% = 7%) are protected against the proposed increase in the customer charge by CAP participation.

Q. CAN YOU PLACE THE PROPOSED FIXED MONTHLY CUSTOMER CHARGE INTO SOME CONTEXT FOR LOW-INCOME CUSTOMERS OF UGI GAS?

A. Yes. First, as I explain below, the fixed customer charge is paid no matter how much or how little gas a customer uses and, in this regard, the costs are unavoidable. No amount of conservation by the customer will impact those costs. Second, as I document above, UGI Gas has an estimated 153,437 low-income customers on its system. (OCA-II-17). UGI Gas proposes to increase its unavoidable fixed customer charge by $5.35/month (from $14.60 to $19.95), or $64.20/year ($5.35 x 12 = $64.20). The total increase in unavoidable fixed charges to the UGI Gas low-income population is thus $9,850,655 ($64.20 x 153,437). In comparison, the low-income customers of UGI Gas received a total of $10,325,947 in LIHEAP grants in 2021 ($8,992,894 in Cash grants + $1,333,053 in Crisis grants). (OCA-II-2). The increased customer charge standing alone, in other words, will remove 95.4% of the total value of federal fuel assistance being delivered to low-income customers.

Q. WHY ISN'T THIS PROBLEM ASSOCIATED WITH THE RATE INCREASE AS A WHOLE RATHER THAN ASSOCIATED WITH THE INCREASED CUSTOMER CHARGE IN PARTICULAR?

A. In part, the rate increase as a whole does pose problems to low-income customers. In much larger part, however, the problem is associated with the increased fixed monthly customer charge. The increased customer charge is an unavoidable fixed monthly fee. Even if low-income customers could reduce their usage, they would not be able to avoid any part of the proposed increase in the fixed monthly customer charge. UGI Gas witness John Taylor concedes that the Company's proposed rate structure will reduce the revenue collected through the UGI Gas volumetric charge to only 64% of total revenues charged to customers. (St. 11, at 5).

Moreover, UGI has not considered how its proposed increase in the fixed monthly customer charge affects the cost-effectiveness of residential energy efficiency measures, through which a customer might reduce consumption to mitigate the impact of the Company's rate increase. (OCA-II-35).

Q. WHAT DO YOU CONCLUDE?

A. The low-income customers of UGI Gas have difficulty in paying their UGI Gas bills at the present time. (OCA-II-1). In this discovery response, UGI Gas provided the data which the Company reports to BCS each year for inclusion in the annual BCS report on Collections Performance and Universal Service Programs. The total data provided to BCS is somewhat more detailed (e.g., it includes monthly data rather than simply average annual data) than that which BCS presents in its annual report.

Increasing the UGI Gas fixed monthly customer charge will increase the payment difficulties which low-income customers currently face. Not only will the increased customer charge have the same effect on the low-income population as eliminating more than 98% of the existing federal fuel assistance that is provided, it will make it more difficult for low-income customers to control their exposure to unaffordable bills through the implementation of energy efficiency or usage conservation measures. For more than 90% of the UGI Gas low-income population, CAP does not provide affordability protections. For these reasons, I recommend that the residential customer charge proposed by OCA witness Jerome Mierzwa be approved.

Part 2. Weather Normalization Adjustment Clause.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the impact of the Company's proposed Weather Normalization Adjustment ("WNA") on low-income customers. UGI Gas witness John Taylor asserts that the WNA proposal will benefit low-income customers.

He states that "certain customers enrolled in the Customer Assistance Program (CAP) who pay an 'average bill' amount will see lower bill variability for distribution costs during colder than average periods. . ." (UGI Gas St. 11, at 16). He further asserts that "customers receive greater stability in the non-gas portion of their utility bills, a benefit during the winter months when gas prices tend to be at their highest, and a particular benefit for low-income customers with high bills during the lengthy heating seasons in UGI Gas's service areas." (Id., at 22).

Q. IS THERE A BETTER WAY TO PROTECT RESIDENTIAL CUSTOMERS GENERALLY, AND LOW-INCOME CUSTOMERS IN PARTICULAR, FROM BILL VOLATILITY DUE TO WEATHER VOLATILITY?

A. Yes. Enrolling residential customers on budget billing would provide more transparent and consistent protections to residential customers from the volatility in home heating bills. Budget billing allows a customer to spread annual bills in equal installments over an 11-month period (with Month 12 being a reconciliation month).[2] By enrolling in budget billing, a customer will know from month-to-month what their natural gas bill will be. The bills become more predictable, and thus more payable. Figure 1 below shows the variability in the aging of arrears for residential accounts from October 2018 through January 2022 (nearly three complete heating seasons). In each complete cold weather season (October 2018 – April 2019, October 2019 – April 2020, October 2020 – April 2021), the number of residential accounts experiencing short-term nonpayment (30 days arrears) increases, only to decline in the subsequent warm weather months. While the

[2] Budget bills are recalculated every three months in the event that the budget billing amount is substantially over-collecting or under-collecting revenue for the year.

2021 – 2022 heating seasons is not yet complete (data available only through January 2022), the same pattern appears to again exist.

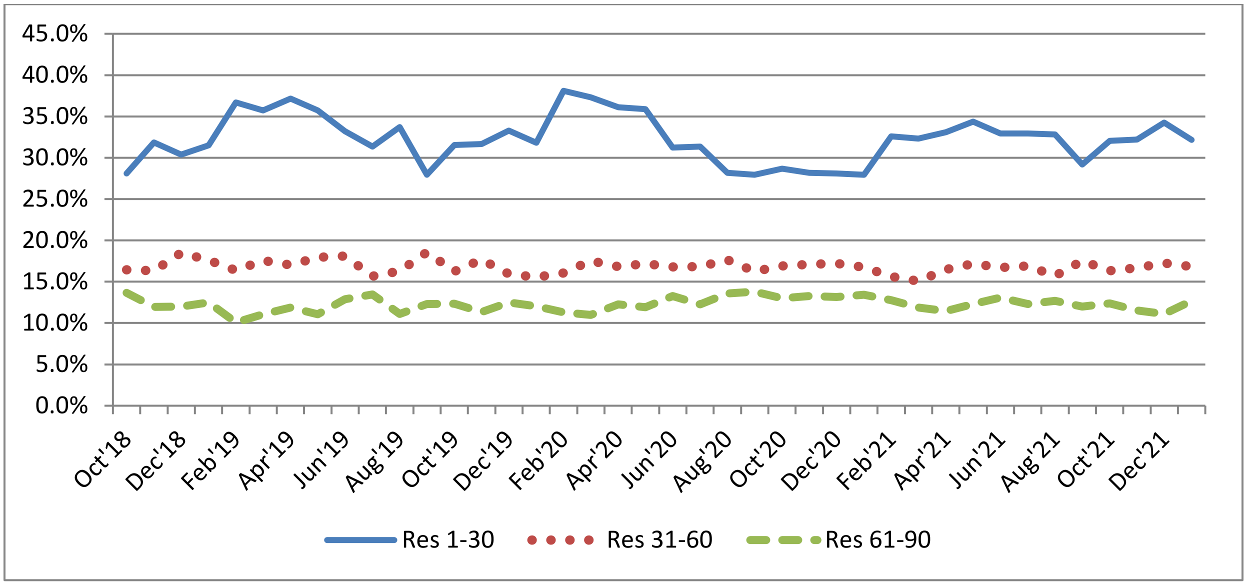

Figure 1. Aging of Arrears –Residential Accounts

The fact that this variation in payment patterns can be attributed to volatility in the level of cold weather bills can be seen in Figure 2 below. This Figure, too, shows the aging of arrears from October 2018 through January 2022. It shows, however, that the variability in dollars of arrears is even higher than the numbers of accounts in arrears. Moreover, while the number of accounts in arrears either 31 to 60 days, or 61 to 90 days remains relatively constant throughout the winter heating seasons, the number of dollars either 31 to 60 days in arrears, or 61 to 90 days in arrears, shows the same seasonal volatility that the number of dollars 1 to 30 days in arrears shows. While implementation of the proposed UGI Gas WNA would not address these problems, emphasized focus on enrolling residential customers in budget billing would be much more likely to do so.

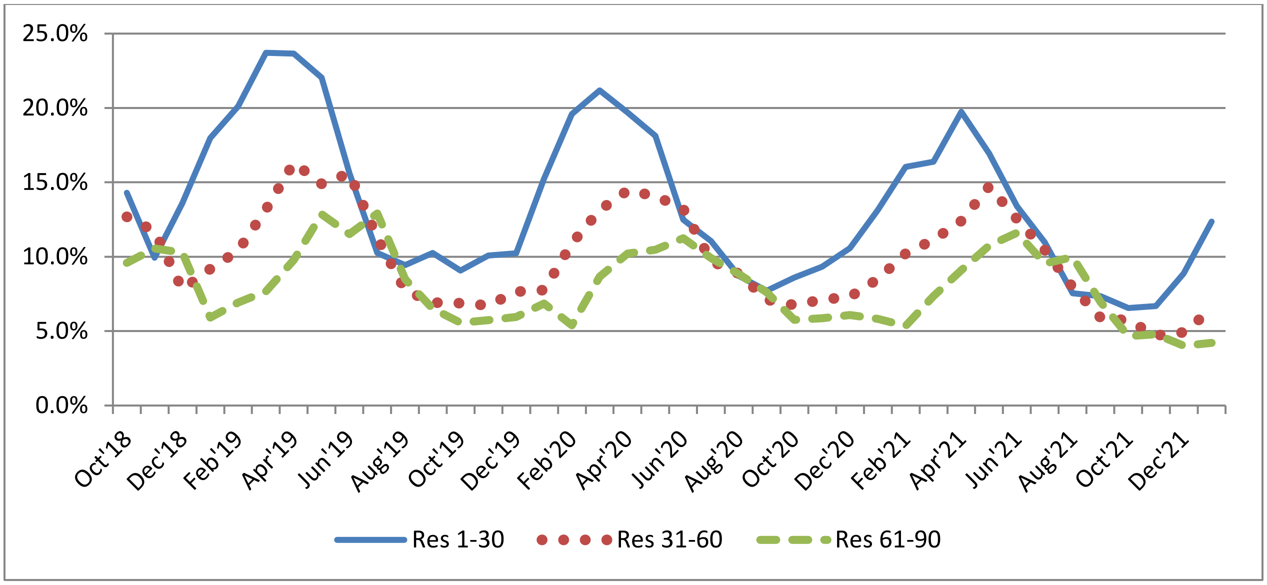

Figure 2. Aging of Arrears –Residential Dollars

Q. DOES BUDGET BILLING INDEED HELP TO SMOOTH BILLS FOR UGI GAS RESIDENTIAL CUSTOMERS?

A. Yes. For the most recent twelve months available (OCA-II-30), UGI Gas reports that 37,445 customers "over-paid" their balance, with an average overpayment of only $51.59. In contrast, 80,346 customers "under-paid" their accounts, with an average under-payment of only $70.04. (OCA-II-30). An "over-payment" or "under-payment" occurs when the sum of the monthly budget billing amounts are greater than or less than actual UGI Gas bills during the 11-month period for which levelized bills are provided.

Q. WHAT DO YOU CONCLUDE?

A. Based on the data above, I conclude that UGI Gas does not need to implement its proposed WNA to increase customer satisfaction with respect to levelizing gas heating bills. The existing Budget Billing program provides a more than satisfactory opportunity to customers who seek to use it. Moreover, Budget Billing has the effect of being able to address the volatility in bill payment that arises as a result of variations in cold weather monthly heating bills. The Budget Billing program would play that role in a much more efficient and effective fashion than would the WNA.

More generally, I conclude first that the recommendations of OCA witness Jerome Mierzwa regarding the Company's proposed WNA be adopted. In addition, the disproportionate adverse impact on low-income customers I have identified provides an additional basis for the recommendations I make below regarding an increase in funding to the UGI Gas Low-Income Usage Reduction Program ("LIURP"). The expansion of LIURP investments will help insulate low-income customers from year-to-year usage swings based on weather. Expanding the number of low-income weatherized homes will mitigate the impacts of the WNA on low-income households.

Part 3. Conversion of Residential Customers to Natural Gas.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I address one issue raised in the Direct Testimony of UGI Gas witness Christopher Brown. Mr. Brown states in response to a question about "environmental stewardship" that "[s]ince 1995, the Company has successfully converted more than 115,000 customers, mostly from fuel oil, to more environmentally-friendly natural gas." (UGI Gas St. 1, at 33). In my discussion below, I do not question whether converting customers to natural gas is "more environmentally friendly" than having those customers remain "mostly [on] fuel oil." From a rate perspective, however, there are universal service cost concerns that UGI should address.

Q. PLEASE EXPLAIN THE CONCERNS YOU HAVE FROM A UNIVERSAL SERVICE PERSPECTIVE.

A. Of the 115,000 conversions Mr. Brown referenced in his Direct Testimony, UGI Gas has converted nearly 30,000 (29,885) in the past five years (2017 – 2021). Of those conversions, a small, but not insignificant, number of accounts (n=354) have been Confirmed Low-Income customers. Nearly half of those Confirmed Low-Income customers are CAP participants (n=168, 47.5%). These numbers, however, will understate the Confirmed Low-Income status, and CAP participant status, of the residents who are converted to natural gas. UGI Gas notes that, "[t]he Company does not track household mobility. Therefore, the Company is only able to query ***the original customers*** who are active in the Customer Information System and ***remain at the converted premise***." (OCA-V-9) (emphasis added). Since 2004, the accounts that have been converted to natural gas have added 425 participants to the UGI Gas CAP program, and 890 Confirmed Low-Income customers. (OCA-V-9). UGI reports that detailed account data is not available prior to 2004. I have, however, previously discussed the high mobility rates within the low-income population in the UGI Gas service territory.

Table 2. Conversions to Natural Gas (2017 – 2021)
By Total Residential, Confirmed Low-Income, and CAP
(OCA-V-9)

	Converted	Confirmed Low-Income[3]	CAP[4]
2017	6,137	82	37
2018	6,646	56	26
2019	6,022	62	30
2020	5,827	69	32
2021	5,253	85	43
Total	29,885	354	168

I have also previously discussed how UGI Gas has confirmed the low-income status of only a fraction of its estimated low-income customers. And only a fraction of the Confirmed Low-Income customers actually participate in CAP. The low-income payment difficulties taken on by UGI Gas when it converts residences to natural gas will, in other words, be much greater than those difficulties associated with the 354 Confirmed Low-Income accounts since 2017 identified as being one of the "original customers who are active in the Customer Information System and remain at the converted premise." (OCA-V-9).

Q. WHAT IS YOUR CONCERN?

A. Low-income households often have far more significant difficulty paying their home heating bills by virtue of their poverty as seen by the data in Table 3 below. There is little

[3] This number is not the total number. This number reflects only those customers who were the original customers at the time of the conversion who remain at the converted premises.

[4] This number is not the total number. This number reflects only those customers who were the original customers at the time of the conversion who remain at the converted premises.

question but that converting low-income households from more expensive fuel oil to relatively less expensive natural gas heat would likely reduce overall home heating costs to these low-income customers and also provide customer service protections that would otherwise not be available to these households. The reality is, however, that without help, low-income customers of UGI Gas often cannot pay their full UGI Gas home heating costs.

Even though the conversion to natural gas may be beneficial, in other words, by converting low-income households to natural gas, UGI Gas is likely imposing additional costs on other ratepayers who may bear the costs of the nonpayment of the Confirmed Low-Income customer accounts.

Table 3. Residential and Confirmed Low-Income Nonpayment Metrics (2019) (UGI Gas South, UGI Gas North)[5]

UGI South	Residential	Confirmed Low-Income
Average arrears	$340.29	$635.39
Pct dollars in arrears	5.4%	24.8%
Percent accounts in arrears	11.2%	37.4%
UGI North	Residential	Confirmed Low-Income
Average arrears	$444.94	$720.04
Pct dollars in arrears	5.4%	20.3%
Percent accounts in arrears	12.7%	33.6%

In addition to taking on the costs of low-income nonpayment, when UGI Gas converts low-income customers to natural gas, it is reasonable to project that many of these low-

[5] BCS Annual Report on Universal Service Programs and Collections Performance (2020) (2020 data not used because of the impact of COVID-19), available at https://www.puc.pa.gov/filing-resources/reports/universal-service-reports/ (last accessed April 6, 2022).

income customers will enroll in UGI's CAP. From the perspective of the low-income customer this is a net positive because not only do they get access to less expensive means of heat by virtue of the conversion from fuel oil to gas, but they also have the benefit of a program that helps with their arrears and lowers their bill by virtue of a PIPP or average bill. However, the impact of this will be to increase CAP costs overall which affects other ratepayers. These CAP costs are annual costs.

Table 4. Average Total CAP Costs per CAP Participant (2018 & 2019) (UGI Gas South, UGI Gas North)[6]

	2018	2019
UGI South	$561	$532
UGI North	$553	$665

My comments above should not be construed as opposing the conversion of low-income customers to natural gas. However, in converting low-income households from other fuels to natural gas, it should also be the responsibility of UGI Gas to take reasonable steps to help control the added costs of those conversions to other residential ratepayers. This responsibility particularly manifests itself when UGI Gas converts low-income households to natural gas.

Moreover, if UGI Gas is truly going to use gas conversion as a mechanism to increase the reduction of carbon emissions, the Company should not only pursue its conversions, but it should pursue efforts to reduce overall energy use as well. When it seeks to expand

[6] BCS Annual Report on Universal Service Programs and Collections Performance (2020) (2020 data not used because of the impact of COVID-19), available at https://www.puc.pa.gov/filing-resources/reports/universal-service-reports/ (last accessed April 6, 2022).

natural gas usage through conversions from other fuels, therefore, UGI Gas should also seek to ensure ***efficient*** natural gas usage through expanded energy efficiency and conservation. This would have the dual impacts of: (1) further reducing carbon emissions consistent with the Company's stated environmental goals; and (2) reducing the costs of CAP (and low-income payment difficulties) for residential ratepayers.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that UGI Gas be directed to screen customers who the Company assists in their conversion to natural gas, as Mr. Brown discusses ("the Company has successfully converted more than 115,000 customers"), to identify those converted customers as Confirmed Low-Income customers and to enroll those customers in CAP where appropriate. I further recommend that the Company add a new incremental component to its Low-Income Usage Reduction Program (LIURP) through which it will provide LIURP investments to Confirmed Low-Income customers as part of the process of converting those customers to natural gas. According to the most recent BCS annual Report on Universal Service Programs and Collections Performance,[7] the average UGI Gas North LIURP cost per job for gas heating was $6,593 in 2019. The average UGI Gas North LIURP cost per job for gas heating was $5,746 in 2019. (See also, OCA-II-1-1, at 7, 16).

[7] Available at https://www.puc.pa.gov/filing-resources/reports/universal-service-reports/ (last accessed April 6, 2022).

While UGI Gas merged its two gas divisions in its last rate case, the Company did not disaggregate the number of gas conversions it identified between UGI gas divisions. Given the number of Confirmed Low-Income gas conversions in 2021 (85), at the averaged UGI Gas LIURP cost per job of $6,170, the total additional LIURP budget would be $524,450.

Q. WHY DOES THIS NEED TO BE AN ADDITIONAL LIURP BUDGET?

A. If UGI Gas were simply to redirect part of its existing LIURP budget to serving these gas conversion customers, there would be no net gain. To the extent that gas conversion customers were served, low-income customers who would have been served in the absence of the gas conversion would be left out.

Q. IS THE ADDITIONAL BUDGET YOU IDENTIFY ABOVE THE TOTAL INCREMENTAL INCREASE IN THE UGI GAS UNIVERSAL SERVICE COSTS?

A. No. Treating these low-income customers with LIURP services will result in decreased bills that, in turn, will result in a dollar-for-dollar decrease in CAP benefits. According to the most recent BCS annual Report on Universal Services Programs and Collections Performance, cited above, the average annual bill reduction arising from LIURP gas heating job investments was $304 in 2018 and $324 in 2017.[8] Annual CAP credits for both UGI South ($417 in 2018, $479 in 2019) and UGI North ($440 in 2018; $375 in 2019) exceeded these bill reductions. As a result, any increase in total universal service

[8] The BCS annual report does not report savings for each gas utility. Instead, these savings are total LIURP gas heating job savings.

spending due to an increase in the LIURP budget will be offset by a decrease in total universal service spending due to a decrease in the CAP budget. Moreover, to the extent that LIURP investments are made prior to enrolling a customer in CAP, the resulting bill reductions will reduce the level of arrears subject to arrearage forgiveness pursuant to the CAP.

Q. DOES YOUR RECOMMENDATION AFFECT THE RATES TO BE SET IN THIS PROCEEDING?

A. No. My recommendation would be paid through the Company's universal service charge. Through the reconciliation process of the Universal Service Rider, the total costs will be collected taking into account: (1) the number of gas conversions that occur in a particular year; (2) the number of gas conversions that are Confirmed Low-Income customers; (3) the number of Confirmed Low-Income gas conversion customers that are served by the additional LIURP services I recommend; (4) the number of Confirmed Low-Income gas conversion customers served through LIURP that are CAP participants; (5) the bill reductions generated for those Confirmed Low-Income gas conversion customers served through LIURP that are CAP participants; and (6) the resulting CAP credit reductions resulting from those bill reductions. In turn, the level of the resulting CAP and arrearage forgiveness credit reductions depends on the income and Poverty Level of the CAP participants (which dictate the level of CAP credits in the absence of the LIURP treatment). Taking account of this myriad of interacting influences is precisely why the Universal Service costs are collected through the Universal Service Rider.

Part 4. UGI Universal Service Performance.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine the extent to which UGI Gas generates an appropriate participation in its CAP program. Rather than focusing on what UGI Gas is doing (i.e., its activities), in this section of my testimony, I will focus on an assessment of UGI Gas enrollment outcomes (i.e., its results).

Q. PLEASE EXPLAIN THE DISTINCTION YOU ARE MAKING WHEN YOU IDENTIFY "ACTIVITIES" AND "OUTCOMES."

A. Measuring "outcomes" is to be distinguished from measuring "activities" and measuring "outputs." An "activity" is defined as the work performed that directly produces products or services. The "output" of an activity is the direct result of program activities. The "outcome" of a program is the accomplishment of program objectives attributable to program outputs.

Performance measurement has been growing now for nearly 30 years in both public and private programs. Perhaps the best-known application is the federal Government Performance and Results Act of 1993. GPRA was designed to address the same conceptual issues that UGI Gas must address for its low-income universal service programs: to grapple with how to best improve effectiveness and service quality while limiting costs. It shifts the focus from program activities to program results.

According to GPRA, "[t]he key concepts of this performance-based management are the need to define clear agency missions, set results-oriented goals, measure progress toward achievement of those goals, and use performance information to help make decisions and strengthen accountability." Utilities face the same sort of problems in measuring efficiency as do federal agencies. As the U.S. General Accounting Office has observed, "[m]any agencies have a difficult time moving from measuring program activities to establishing results-oriented goals and performance measures."[9]

Within this construct, in my discussion below, I will focus not on what UGI Gas should or should not be *doing*. I will instead focus on what UGI Gas should or should not be *accomplishing*.

Q. WHAT IS THE FIRST STEP IN MEASURING OUTCOMES?

A. The first step in measuring outcomes is to establish measurable objectives or goals (i.e., outcomes) that UGI Gas should seek to achieve. After establishing these measurable outcomes, UGI Gas can engage in an ongoing process to determine whether those objectives have, in fact, been achieved and, if not, what needs to be modified in order to improve performance.

[9] James Hinchman (Acting Comptroller General). (June 24, 1997). Managing for Results: The Statutory Framework for Improving Federal Management and Effectiveness, at 1, Testimony before U.S. Senate Committee on Appropriations and Committee on Governmental Affairs (GAO/T-GGD/AIMD-97-144).

Q. WHAT MEASURABLE PERFORMANCE GOALS DO YOU RECOMMEND UGI GAS SHOULD ESTABLISH?

A. I recommend three measurable performance goals that UGI Gas should seek to accomplish with respect to CAP:

- **<u>Outcome Objective #1</u>**: UGI Gas should achieve a Confirmed Low-Income identification rate, as a percentage of estimated low-income customers, no less than the Confirmed Low-Income identification rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).

- **<u>Outcome Objective #2</u>**: UGI Gas should achieve a CAP participation rate, as a percentage of Confirmed Low-Income customers, no less than the CAP participation rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).

- **<u>Outcome Objective #3</u>**: UGI Gas should achieve a CAP default rate as a percentage of participants in the lowest poverty level range that is no less than the CAP default rate in that poverty level range for Pennsylvania gas utilities as a whole.

Through the first Outcome objective, UGI Gas will seek to ensure that it is adequately identifying its low-income customers. Through the second and third Outcome objectives, UGI Gas will seek to ensure that, having identified its low-income population, it is then enrolling its known low-income customers into its primary low-income assistance program.

In subsequently assessing actual performance relative to the desired performance (measured in terms of the identified Outcomes), neither the Commission nor other stakeholders will focus on what UGI Gas is or is not doing in the abstract. A review of what UGI Gas is (or is not) doing will instead occur within the context of whether those activities are cost-effectively and cost-efficiently generating the identified outcomes. If UGI Gas is not achieving its identified performance objectives, it would need to identify the cause of the performance shortcoming and decide what it needs to do differently in order to improve its performance.

Q. DO YOU RECOMMEND A SYSTEM OF PENALTIES OR REWARDS BASED ON PERFORMANCE RELATIVE TO THE IDENTIFIED OBJECTIVES IN THIS PROCEEDING?

A. No. While I would reserve the right to propose a system of penalties (for poor performance as measured by a continuing failure to meet the stated performance objectives) or rewards (for superior performance as measured by exceeding the performance objectives) in a future rate case, my intention in this proceeding is to change the conversation about the identification of low-income customers, about CAP enrollment, and about the participation of the lowest income customers in CAP, from a discussion of what UGI Gas should be doing to a discussion of what UGI Gas should be accomplishing.

Q. HOW DOES UGI GAS PERFORM RELATIVE TO PENNSYLVANIA NATURAL GAS UTILITIES IN IDENTIFYING THEIR CONFIRMED LOW-INCOME CUSTOMERS, WHICH IS YOUR PROPOSED OUTCOME OBJECTIVE #1?

A. As I discussed above with respect to my proposed Outcome Objective #1, UGI Gas identifies fewer of its estimated low-income customers as Confirmed Low-Income customers than do Pennsylvania's natural gas utilities as a whole. The data available by which to measure this performance metric is readily available in the annual BCS report on Universal Service Programs and Collections Performance. As documented in Table 5 below, Pennsylvania's natural gas utilities (without UGI Gas) identify 66.4% of their estimated low-income customer base as Confirmed Low-Income customers. In contrast, UGI Gas identifies 48.3% of its estimated low-income customer base as Confirmed Low-Income customers. For UGI Gas to perform at least as well as all other Pennsylvania utilities, it would need to identify 88,026 of its estimated low-income customers as Confirmed Low-Income customers. Application of Performance Objective #1, in other words, would indicate that UGI Gas is under-performing relative to identifying its Confirmed Low-Income customers.

Table 5. Identification of Estimated Low-Income (LI) Customers as Confirmed Low-Income (L)
Pennsylvania Natural Gas Utilities / UGI Gas (2019)

	Estimated LI	Confirmed LI	% Confirmed LI of Estimated LI
Columbia	97,268	67,582	69.5%
NFG	60,947	32,282	53.0%
PECO Gas	74,914	24,977	33.3%
Peoples	84,437	67,718	80.2%
Peoples Equitable	58,791	41,585	70.7%
PGW	197,855	147,014	74.3%
Total (without UGI)	574,212	381,158	66.4%
UGI South	86,314	39,108	45.3%
UGI North	46,297	24,934	53.9%
Combined UGI	132,611	64,042	48.3%

Q. HOW DOES UGI GAS PERFORM RELATIVE TO PENNSYLVANIA NATURAL GAS UTILITIES IN ENROLLING THEIR CONFIRMED LOW-INCOME CUSTOMERS INTO CAP, WHICH IS YOUR PROPOSED OUTCOME OBJECTIVE #2?

A. As I discussed above with respect to my proposed Outcome Objective #2, UGI Gas enrolls fewer of its Confirmed Low-Income customers as CAP participants than do Pennsylvania's natural gas utilities as a whole. As with the discussion above regarding the identification of Confirmed Low-Income customers, the data available by which to measure this performance metric is readily available in the annual BCS report on Universal Service Programs and Collections Performance.[10] As documented in Table 6 below, Pennsylvania utilities (excluding UGI Gas) enroll 35.1% of their Confirmed Low-Income customers into CAP. In contrast, UGI Gas enrolls only 21.5% of its Confirmed Low-Income customers into CAP.

Given UGI's current level of Confirmed Low-Income customers, for UGI Gas to perform at least as well as all other Pennsylvania utilities, it would need to enroll 22,479 of its Confirmed Low-Income customers as CAP participants (64,402 x 0.351 = 22,479). Application of Performance Objective #2, in other words, would indicate that UGI Gas is under-performing relative to CAP enrollment of Confirmed Low-Income customers.[11]

[10] Available at https://www.puc.pa.gov/filing-resources/reports/universal-service-reports/ (last accessed April 6, 2022).

[11] If UGI were to achieve its Outcome Objective #1 of identifying 88,026 Confirmed Low-Income customers, it would need to enroll 30,897 customers in CAP to achieve Outcome Objective #2 (88,097 x 0.351 = 30,897).

Table 6. Identification of Estimated Low-Income (LI) Customers as Confirmed Low-Income (L) Pennsylvania Natural Gas Utilities / UGI Gas (2019)			
	Confirmed LI	CAP Participants	% CAP of Confirmed LI
Columbia	67,582	23,551	34.8%
NFG	32,282	7,294	22.6%
PECO Gas	24,977	19,427	77.8%
Peoples	67,718	17,034	25.2%
Peoples Equitable	41,585	12,928	31.1%
PGW	147,014	53,722	36.5%
Total (without UGI)	381,158	133,956	35.1%
UGI South	39,108	8,422	21.5%
UGI North	24,934	5,369	21.5%
Combined UGI	64,042	13,791	21.5%

Q. PLEASE EXPLAIN THE BASIS FOR YOUR PROPOSED OUTCOME OBJECTIVE #3.

A. My proposed Outcome Objective #3 measures a different type of performance than do the first two proposed Outcome Objectives. Outcome Objective #3 is directed toward ensuring appropriate participation of customers in the lowest range of Poverty Level in the UGI Gas CAP. Outcome Objective #3, however, does not compare the percentage of customers with income below 50% of Poverty enrolled in CAP to the percentages enrolled by other gas utilities. Other gas utilities may have different total percentages of their customer base with income at or below 50% of Poverty. Nor does the proposed Outcome Objective #3 compare the percentage of CAP customers with income below 50% of Poverty to the percentage of total households in the service territory with income below 50% of Poverty. Not all customers with income below 50% of Poverty would necessarily be natural gas customers.

Accordingly, the proposed Outcome Objective #3 seeks to measure the extent to which UGI Gas retains its lowest income customers once those customers are enrolled in CAP. It is possible to do this by examining “default rates.” According to the annual BCS report on Universal Service Programs and Collections Performance, the “default rate” is “calculated by dividing the average monthly CAP participation rate at each poverty level by the total annual number of defaults for each poverty level.” BCS, which reports default rates in its annual report, states that “[a]ctions resulting in CAP defaults include missing payments, making late payments, or failing to recertify.” (2020 BCS, at 61). By far, since July 2021, when utilities began again to remove CAP customers for failing to recertify after not having done so during the height of COVID-19, failing to recertify has been the biggest reason for default. From July 2021 through January 2022, UGI Gas removed 4,361 CAP participants for failing to recertify. (OCA-II-16). Even before COVID, however, failing to recertify was the largest cause of program default. (Id.)[12]

Q. HOW DOES UGI GAS PERFORM RELATIVE TO THE THIRD PROPOSED OUTCOME PERFORMANCE OBJECTIVE YOU HAVE IDENTIFIED?

A. In 2019, according to the most recent BCS annual report on Universal Service Programs and Collections Performance,[13] UGI had a CAP default rate for customers with income

[12] Not all program exits represent “program defaults.” For example, having a customer move, or die, or become over-income is not a program default.

below 50% of Poverty, which is my proposed Outcome Objective #3, that was higher than the statewide average default rate for gas utilities, and was higher than every other gas utility excepting PGW. Table 7 presents the data. UGI South had a default rate within the population below 50% of Poverty of 31.4%, while UGI North had a default rate within that population of 31.3%. PGW's default rate for its population below 50% of Poverty was 32.8% in2019. Similarly, UGI Gas' default rate for CAP participants with income at or below 50% of Poverty was higher than every other gas utility in 2018. UGI South had a default rate of 33.4% while UGI North had a default rate of 31.3%. The next highest gas utility was PECO-Gas (28.1%), while the statewide average for gas utilities was 25.4%.

Table 7. CAP Default Rate for Participants with Income at or Below 50% of Poverty
Pennsylvania Natural Gas Utilities / UGI Gas (2018 - 2019)

	2018	2019
Columbia	16.3%	19.1%
NFG	19.0%	24.4%
PECO Gas	28.1%	28.0%
Peoples	23.0%	24.9%
Peoples Equitable	23.2%	23.7%
PGW	26.9%	32.8%
Total/Industry Average (with UGI)	25.4%	27.0%
UGI South	33.4%	31.4%
UGI North	31.3%	31.3%

Q. WHAT DO YOU CONCLUDE?

A. Using the three performance metrics I identify above, it is evident that UGI Gas is under-performing other Pennsylvania utilities in the extent to which it is confirming the low-income status of its natural gas customers and in the extent to which it is enrolling the customers for whom it has confirmed their low-income status into CAP. In addition, UGI Gas is under-performing in the extent to which it prevents CAP defaults within its population of CAP participants with income at or below 50% of Poverty. I conclude that the use of the performance metrics I recommend shows inadequate performance by UGI Gas that should be remedied.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that rather than having the Commission engage in continuing reviews of the specific activities that UGI Gas pursues to identify its low-income customers and to enroll those customers in CAP, the Commission instead require UGI Gas to measure its outcome performance in these respects on an ongoing basis. The Commission should determine that it will use these outcome performance metrics to review the adequacy of UGI Gas performance in future rate cases.

Q. WHY IS IT APPROPRIATE TO ADDRESS THIS ISSUE IN THIS RATE PROCEEDING RATHER THAN IN THE COMMISSION'S REVIEW OF UGI'S UNIVERSAL SERVICE AND ENERGY CONSERVATION PLAN (USECP)?

A. If for no other reason, the under-performance on the three Outcome Objectives I have identified above are reasons that the Company's proposed increase to its return on equity should not be approved.

In addition, however, my recommendation above could not have been advanced in the UGI Gas USECP given that the rate case proposals advanced in this proceeding had not yet been filed. My recommendations above are designed to determine whether UGI is adequately protecting low-income customers from the consequences of this rate proceeding. UGI Gas, itself, asserts that enrollment in CAP is one reason why it projects that this proposed rate case will have no adverse effect on low-income customers. (CAUSE-PA-I-1). The rate case had not been filed at the time UGI submitted its most recent USECP, and additional rate cases may be filed before any future USECP is submitted to the Commission for review. The Outcome Objectives proposed to measure the performance of UGI Gas could not have been raised in the USECP review. And the review of performance on Outcome Objectives would not necessarily be an issue in any future USECP review.

Part 5. Continuing COVID-19 Relief Efforts.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I examine whether UGI Gas should continue to provide certain expanded universal activities which it began providing in response to the novel Coronavirus health pandemic. While residential arrears have begun to decline in recent months, they have not returned to pre-COVID levels. Total dollars of residential arrearages and total dollars of arrearages aged 90-days old or older have declined in 2021 relative to 2020, but remain higher than in 2019. Moreover, the dollars of arrearages owed at the time of nonpayment service disconnections remain higher at the end of 2021 than they were at the end of 2019.

Table 8 shows the data. While total 90-day arrears (in dollars) are lower in all three months (October, November, December) of 2021 than they were in 2020, they remain consistently higher than they were in the corresponding three months of 2019. Moreover, in all three months (October, November, December), the percentage of total residential arrears that are 90-days old (or older) is higher in 2021 than they were in either 2019 or 2020.

Table 8. Residential Arrears
October – December (2019 – 2021) (OCA-II-39)

	Oct 19	Oct 20	Oct 21	Nov 19	Nov 20	Nov 21	Dec 19	Dec 20	Dec 21
Total Arrears	$34,167,129	$45,965,739	$41,420,665	$33,972,055	$45,948,466	$41,231,296	$38,858,323	$47,549,467	$43,032,651
Arrears 90+ Days	$27,652,882	$37,372,199	$35,600,619	$27,311,405	$37,416,338	$35,413,444	$27,442,340	$37,130,511	$35,388,132
Pct 90+ days	81%	81%	86%	80%	81%	86%	71%	78%	82%
Total Disconnects	3,814	0	1,830	1,113	0	1,774	1	40	0
Arrears at Disconnect	$4,477,872	$0	$2,400,722	$1,228,637	$0	$2,407,129	$2,692	$45,851	$0
Avg Arrs at Disconnect	$1,174	---	$1,312	$1,104	---	$1,357	---	---	---

Continuing payment difficulties are evidenced by data on residential disconnections as well. While there was a sharp drop in October 2021 disconnections relative to 2019, there was a 60% increase in disconnections in November 2021 relative to November 2019 ([1,774 – 1,113] / 1,113 = 0.594). Moreover, the average arrearage balance at the time of disconnection remained higher in October and November 2021 than the average arrearage balance was at the time of disconnection in October and November 2019.[14]

[14] There were no disconnections in December 2021 and only one in December 2019, so no comparison can be made.

From this data, it is clear that, while circumstances are improving relative to the heart of the COVID public health and economic crisis that existed throughout 2020 and much of 2021, the COVID-related payment difficulties facing UGI Gas customers are not behind the Company. Payment difficulties have declined, but are not back to pre-COVID levels. More customers have long-term arrears. More customers have sufficiently high arrears that they are facing nonpayment disconnections.

Q. DID UGI GAS OFFER EXTENDED COVID-RELATED PAYMENT PLANS TO CUSTOMERS IN ARREARS?

A. Yes. According to the Company, "in compliance with the April 1, 2021 modification of the PUC Order at Docket No. M-2020-0319244, upon request, UGI offered a payment arrangement with minimum terms of: 5 years for customers below 250% FPL, 2 years for customers between 250% and 300% FPL, 1 year for customers above 300% FPL, and 18-months for small business customers." (OCA-II-40). Moreover, UGI reports that it has "ceased assessing security deposits on existing customers until November 17, 2021." (Id.)

Q. HAS UGI OFFERED OTHER EXTENDED COVID RELIEF PROGRAMS TO ITS RESIDENTIAL CUSTOMERS?

A. Yes. The Company raised the income eligibility for its hardship grants from 200% of FPL to 250% of FPL from the period of July 2020 through December 2021. In addition, pursuant to the Settlement reached in the 2020 Gas Rate Case (Docket R-2019-3015162), the Company expanded the maximum grant size from $400 to $600 between July 2020 and December 2021. The Company agreed to provide an additional, one-time, $2.0 million disbursement ($1 million from UGI Gas and $1 million from interstate pipeline refunds) to the UGI Gas Operation Share program on a non-rate recoverable basis. (OCA-III-44).

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the COVID responses that UGI had previously agreed to extend through the end of 2021 be continued until UGI Gas' next base rate case. In particular, I recommend:

- UGI commit to continuing to offer the extended payment plans as identified in the April 2021 Order in Docket M-2020-0319244;

- UGI reinstate its waiver of residential deposits for existing customers. The COVID-related payment difficulties of residential customers are not indicators of long-term payment risks. And the imposition of a cash security deposit remains an impediment to customers retiring the arrears that they have already incurred;

- UGI reinstate its expanded hardship grant income eligibility, along with its expanded maximum hardship grant; and

- UGI make an additional $1.0 million non-rate recoverable contribution to its hardship fund on an additional one-time basis.

Part 6. Stabilizing Low-Income Usage/Bills.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I will explain how various aspects of the relief sought by UGI Gas in this rate case proceeding synergistically operate to the detriment of low-income customers. Even aside from the size of the rate hike, itself, the proposed increase in the residential customer charge makes a greater proportion of a low-income customer's monthly bill more difficult to reduce by having a higher proportion of the bill be an unavoidable fixed charge. Through the Weather Normalization Adjustment (WNA), UGI Gas seeks to transfer to ratepayers the risk of climate-change induced increases in the volatility of weather, when that increased weather volatility is caused, at least in part, by the very consumption of fossil fuels. In the meantime, UGI Gas confirms the low-income status of only half of the estimated number of low-income customers on its system, and enrolls only little more than a quarter of the Confirmed Low-Income customers it has identified in its CAP. As I discuss in detail above, a full 86% of UGI Gas' low-income customers are not protected from the harms of the various Company proposals in this rate proceeding through participation in CAP.

As a result, low-income customers have an average arrearage which is two times higher than residential customers. Low-income customers incur dollars of arrears at a rate between four and five times higher than residential customers. In addition, of the 17,309 residential customers UGI Gas disconnected for nonpayment in 2019, nearly 2,000 (1,877, more than one-in-ten) either remained without heat or were using an unsafe heating source (as defined by the PUC) at the start of the subsequent cold weather heating season.

In the meantime, the climate change which UGI Gas seeks to insulate itself from the impacts of continues to have disproportionate impacts on low-income customers. By the Year 2100, extreme heat waves that historically occurred once every 20 years are predicted to occur every other year.[15] It is not merely "outdoor" climate-induced health effects that represent the harms to be avoided through usage reduction programs. Because Americans spend 67% of their time in their homes, indoor air quality also affects health. Indoor air pollutants have been ranked as among the top five environmental risks to public health. Poor indoor air quality in the home has been linked to cancer, to asthma, and to carbon monoxide poisoning.[16]

The confluence of the harms associated with outdoor air quality and those associated with indoor air quality should be recognized and responded to. One consistent piece of advice given to people on how to avoid the adverse impacts of poor outdoor air quality is to remain indoors.[17] This advice assumes that indoor air quality is superior to outdoor air quality. But this means that people whose indoor air quality is compromised may be more susceptible to adverse health effects from indoor air than the population at large.

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[15] Kaswan (2012). "Domestic Climate Change Adaptation and Equity," 42 Environmental L.Rep. News & Analysis 11125, available at https://heinonline.org/HOL/LandingPage?handle=hein.journals/elrna42&div=150&id=&page= (last accessed April 10, 2022).

[16] The purpose of this discussion is not to comprehensively document the relationship between housing quality and adverse health outcomes. Those interested in the topic should explore the literature of "ecosocial epidemiology." *See generally* Shafiei, et al. "Reducing Health Disparity through Healthy Housing," *in* Healthy and Safe Homes: Research, Practice and Policy Chapter 4, pp.73-90 (Rebecca Morley et al. eds., 2011), available at https://ajph.aphapublications.org/doi/10.2105/9780875531977ch04 (last accessed April 10, 2022). *See also* Krieger, "Theories for Social Epidemiology in the 21st Century: An Ecosocial Perspective," 30 Int'l J. Epidemiology 668, 671-673 (2001), available at https://academic.oup.com/ije/article/30/4/668/705885 (last accessed April 10, 2022). For a discussion of the positive health impacts flowing from an improvement in housing quality, see generally, Thompson et al., "The Health Impacts of Housing Improvement: A Systematic Review of Intervention Studies from 1887 to 2007," 99 Am. J. Public Health S681 S682-S689, S690-S691(2009), available at https://www.researchgate.net/publication/51439420_The_Health_Impacts_of_Housing_Improvement_A_Systematic_Review_of_Intervention_Studies_From_1887_to_2007 (last accessed April 20m, 2022).

[17] See e.g., Laumbach, Meng and Kipen "What can individuals do to reduce personal health risks from air pollution?" J.Thorac.Dis. 2015 Jan; 7(1): 96–107, available at https://pubmed.ncbi.nlm.nih.gov/25694820/ (last accessed April 10, 2022).

Low-income people are much more likely to be exposed to, and therefore suffer the effects of poor indoor air quality than the general population. So the advice to stay indoors might be good for the majority of people but bad for a minority. When being indoors is just as deadly as being outdoors, there is, quite simply, no place to hide.

Q. HOW DOES THIS DISCUSSION APPLY TO THE UGI GAS SERVICE TERRITORY?

A. When the UGI Gas service territory is defined by community,[18] data provided through the U.S. Department of Housing and Urban Development's Comprehensive Housing Affordability Strategy (CHAS) data base shows that low-income households, and particularly low-income renters:[19]

- Live in older (and presumptively less energy efficient) housing;
- Live in housing units with more "severe housing problems."

Moreover, the CHAS data demonstrates that low-income households in the communities served by UGI Gas are disproportionately likely to be renters.[20] This data demonstrates that low-income households in the UGI Gas service territory are more likely to face the difficulties I identify above, and less likely to be able to redress those difficulties through their own resources.

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[18] When UGI Gas was asked to provide a complete list of the communities served by the utility, it replied that it had data only by county. (OCA-II-18). A list of "cities" was obtained from the UGI Gas tariff.

[19] Available at https://www.huduser.gov/portal/datasets/cp.html#2006-2017_data (last accessed April 8, 2022).

[20] See, CHAS data base, supra note 19, at Tables 2, 3, 5 and 12. Available at https://www.huduser.gov/portal/datasets/cp.html#2006-2017_data (last accessed April 8, 2022).

I examined CHAS data for the following UGI Gas communities: Allentown, Bethlehem, Bloomsburg, Carbondale, Easton, Harrisburg, Hazleton, Lancaster, Lebanon, Lock Haven, Nanticoke, Oil City, Parker, Pittston, Pottsville, Reading, Scranton, Shamokin, Sunbury, Wilkes-Barre, and Williamsport.

Q. WHAT DO YOU RECOMMEND?

A. The primary way to redress the hardships which the UGI Gas rate filing imposes on the Company's low-income customers is to undertake expanded efforts to make the housing of its low-income customers as energy efficient as possible. UGI Gas operates the Low-Income Usage Reduction Program (LIURP) to serve low-income customers. Because of the expanded hardships which UGI Gas will impose on its low-income customers due to the relief that it seeks in this proceeding, UGI Gas should undertake efforts to protect an expanded number of low-income households through its LIURP initiative.

UGI Gas reports that roughly half of the bills it rendered to its Confirmed Low-Income customers in the heating seasons (defined to be October through March) for the past three heating seasons (2018 – 2019, 2019 – 2020, 2020 – 2021) were bills for 151 CCF or more. (OCA-II-18). The data provided by UGI Gas is summarized in Table 9 below.

Table 9. Confirmed Low-Income Bills Exceeding 151 CCF (OCA-II-18(b))

	Monthly Avg # LI Bills (151+ CCF)	Monthly Avg # LI Bills (total)	Pct Total LI Bills (151+ CCF)
Oct 2018-Mar 2019	12,334	21,803	56.6%
Oct 2019-Mar 2020	12,292	26,530	46.3%
Oct 2020 - Mar 2021	14,449	29,599	48.8%

To reach 40% of those low-income customers over a ten-year period would require UGI Gas to serve 5,780 Confirmed Low-Income customers in that period (578 LIURP jobs/year). At a weighted cost of $6,170 (2019 LIURP costs, OCA-II-1), the total cost of doing so would be $3.566 million (5,780 x $6,170 = $3,565,971). To reach this objective, UGI Gas needs to add $1.425 million to its current combined LIURP spending level of $2,140,667 (OCA-I-1, at 6, 15).

Accordingly, to offset the harms imposed on Confirmed Low-Income customers by the relief UGI Gas seeks in this rate case, I recommend that UGI Gas expand its LIURP spending by $1.425 million a year, sufficient to serve 231 additional Confirmed Low-Income customers per year. These additional LIURP jobs are in addition to the LIURP jobs that I recommend above be directed toward low-income households at the time they are converted from other fuels to natural gas.

Q. WOULD THE TOTAL INCREMENTAL UNIVERSAL SERVICE COST OF YOUR PROPOSAL THUS BE $1.425 MILLION A YEAR?

A. No. As with my recommendation above with respect to providing LIURP services to low-income customers who UGI Gas converts to natural gas from a non-gas fuel, investing LIURP dollars would generate universal service cost reductions as well. Bill reductions resulting from LIURP investments will, on a dollar-for-dollar basis, reduce the level of future CAP credits to the extent that the customer is also enrolled in CAP. Moreover, to the extent that a low-income customer receives LIURP services prior to enrolling in CAP, it is more likely than not that the customer will experience reduced arrearages.[21] As a result, there would be a reduction in arrearages subject to forgiveness through the UGI Gas CAP program. Given that CAP Credits and Arrearage Forgiveness credits comprise 93.5% of the total costs of the UGI North CAP program, and comprise 92.8% of the total costs of the UGI South CAP program, these reductions in universal service costs that would offset any LIURP investment would be substantial.

Q. IS THERE A NEED TO QUANTIFY THESE OFFSETS TO THE LIURP SPENDING AND EXPLICITLY RECOGNIZE THEM?

A. No. To the extent that future CAP credits are reduced through the delivery of LIURP services, those reduced credits will be automatically recognized in the Universal Service Rider. The Rider only allows UGI Gas to recover those CAP credits that have been actually paid. The same is true for reductions in future arrearage forgiveness credits. Given that the Universal Service Rider allows UGI Gas to recover only those arrearage forgiveness credits that are actually granted, to the extent that the delivery of LIURP investments will reduce those arrearage forgiveness credits, the collection of universal service costs will, without further action, be adjusted to reflect those reductions.

[21] Shingler (2008). Long Term Study of Pennsylvania's Low-Income Usage Reduction Program: Results of Analyses and Discussion, available at https://aese.psu.edu/research/centers/csis/publications (last accessed April 8, 2022).

Q. WHY ISN'T THIS RECOMMENDATION MORE APPROPRIATELY PRESENTED IN UGI'S PROCEEDING TO REVIEW ITS UNIVERSAL SERVICE AND ENERGY CONSERVATION PLAN (USECP)?

A. The base spending for the UGI Gas LIURP program is considered in the proceeding to review the UGI Gas USECP. However, my recommendation above could not have been advanced in the UGI Gas USECP given that the rate case proposals advanced in this proceeding had not yet been filed. My recommendation above is designed to respond to, and to reflect, the necessary LIURP spending to respond to the proposals advanced by UGI Gas in *this* proceeding. They could not have been raised in the USECP review.

Part 7. Allocation of Universal Service Costs.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I briefly explain why the universal service costs of UGI Gas should be allocated amongst all customer classes, rather than being allocated exclusively to the residential customer class. Despite this explanation, I do not propose that the PUC consider a reallocation in this proceeding. The issue of how to allocate UGI Gas universal service costs should be deferred to the next UGI Gas rate case.

Q. WHY DO YOU PROPOSE TO DEFER CONSIDERATION OF THE APPROPRIATE ALLOCATION OF UNIVERSAL SERVICE COSTS?

A. As I discuss in more detail in the section of my Direct Testimony discussing the ongoing COVID_19 pandemic, while the public health issues created by COVID-19 are being brought under control, the economic crisis associated with the pandemic continue to affect Pennsylvania consumers. Given these unusual economic times in which we are living, it seems to be an inappropriate moment to consider a change in policy such as how to allocate universal service costs among customer classes. By deferring the consideration of this issue, it is possible for the PUC to review how such allocations should occur within the context of normal economic circumstances for all customer classes.

Q. PLEASE EXPLAIN WHY YOU MENTION THIS ISSUE GIVEN THAT YOU DO NOT PROPOSE A CHANGE IN THE UNIVERSAL SERVICE COST ALLOCATION IN THIS PROCEEDING.

A. In its 2019 Final Policy Statement and Order in the PUC's generic investigation into energy affordability in Pennsylvania (Docket M-2019-3012599),[22] the Commission explicitly acknowledged that, historically, it allocated universal service costs exclusively to residential customers, but then stated that "our review of Pennsylvania's current universal service model in the *Review* and *Energy Affordability* proceedings has provided reasons to reconsider this position." (Final Policy Statement and Order, at 92). The Commission observed that "[t]he current cost-recovery method for universal services, including CAP costs, is putting a significant burden on residential customer bills. . ." (Id.). The Commission's decision to substantially reduce the definition of an "affordable" burden will create even more universal service costs and will increase that "significant burden" even more. According to the Commission:

[22] http://www.puc.pa.gov/about_puc/consolidated_case_view.aspx?Docket=M-2019-3012599 (November 5, 2019) (last accessed April 21, 2021).

> Given the significant past increase in EDC universal service spending – and the anticipated increases in both EDC and NGDC universal spending through 2021 – the Commission is concerned that recovering CAP costs (as well as other universal service costs) from only residential ratepayers will continue to make electric and/or natural gas bills increasingly unaffordable for non-CAP customers, especially those with incomes between 151-200% of the FPIG.

(Id., at 95). I agree with these observations. There is a substantial population of UGI Gas customers who have difficulties in paying their utility bills without being sufficiently "low-income" to qualify for CAP. The current CAP costs could prove to be problematic for these customers, and those costs will increase in the future, both for the reasons identified in the Commission's Final Order (pages 94 – 95) and for the reason that the Commission has revised its Final Policy Statement recommending reductions of the percentage of income payments to be charged to CAP customers.[23]

The Commission stated in its Final Order that "the Commission finds it appropriate to consider recovery of the costs of CAP costs from all ratepayer classes. Utilities and stakeholders are advised to be prepared to address CAP cost recovery in utility-specific rate cases consistent with the understanding that the Commission will no longer routinely exempt non-residential classes from universal service obligations. . ." (Id., at 99, notes omitted).[24]

[23] While the Office of Consumer Advocate has urged that CAP is designed to address long-term structural poverty, these costs might increase even more to the extent that COVID-19 results in structural job loss. Temporary loss of income due to COVID-19 should be considered to be addressed through a PUC-approved emergency relief program.

[24] The Commission observed that it was not making "a final precedential decision regarding cost recovery in this docket. We are merely providing that the recovery of CAP costs in particular can be fully explored in utility rate cases henceforth." (Id., at note 150).

Q. HOW DO YOU RESPOND TO THIS PUC GUIDANCE?

A. While I am not recommending that universal service costs be allocated across all customer classes in this proceeding, for the reasons set forth above and further below, I agree that:

- the PUC's observation was accurate when it found in its 2019 Final Order that poverty is "not just [a] residential class problem."

- the Pennsylvania PUC's observation was accurate when it found in its Final Order (2019) that several factors "contribute to households struggling to afford utility service" and that, amongst those factors are "poverty, poor housing stock, and other factors."

- the Pennsylvania PUC was correct when it found in Final Order (2019) that poverty is a broad-based social problem not associated with any particular customer class, including specifically not being associated with the residential class exclusively.

- the Pennsylvania PUC was correct when it found in its Final Order (2019) that "helping low-income families maintain utility service and remain in their homes is also a benefit to the economic climate of a community."

- the Pennsylvania PUC was correct when it found in its Final Order (2019) that "Clearly, there is a persuasive argument to be made that home heating and energy assistance for low-income households serves a public good whose responsibility is not merely other residential ratepayers."

- The Pennsylvania PIC was correct when it found in its Final Order (2019) that "while there are strong arguments to be made that non-residential classes do benefit from universal services, there are also strong arguments to be made in favor of multi-class allocation even if one discounts any non-residential benefits."

Finally, I agree that the PUC's observation is applicable to UGI Utilities, when the Commission observed in its Final Order (2019), quoted above, that: "In approving PGW's practice of recovering such costs across all ratepayer classes, we noted that 'all firm customers, including commercial and industrial customers, benefit indirectly from PGW's extensive low-income assistance programs.'" (internal note omitted).

Q. WHAT DO YOU CONCLUDE AS TO UNIVERSAL SERVICE COST ALLOCATION FOR UGI GAS?

A. Notwithstanding this willingness and ability to demonstrate the applicability of these previous PUC findings to UGI Utilities, for the reasons stated above, I do not present the issue of the allocation of universal service costs in this proceeding, but reserve this issue for a future proceeding.

Part 8. Proposed Increase to ROE Based on Management Excellence.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. UGI Gas requests that it be granted an additional equity return of 0.20% to reflect what it asserts is exemplary management. (UGI Gas St. 1, at 38 – 39). UGI witness Chris Brown asserts that this excellence is manifested in safety, community partnership, and the commitment to customer service. Based on my discussion below, I conclude that the recommendation of OCA witness David Garrett should be adopted with respect to this request for an additional return on equity.

Q. HAVE YOU REVIEWED CUSTOMER SATISFACTION AS IT RELATES TO UGI GAS?

A. Yes. UGI Gas ranks consistently toward the middle to bottom of customer satisfaction as reported by the Pennsylvania PUC. I reviewed the BCS 2020 "Customer Service

Performance Report."[25] I use this data because it is the data that the PUC has deemed appropriate as a basis upon which to review utility performance. My review of customer satisfaction finds that:

- UGI Gas tied with PGW as ranking last among Pennsylvania's natural gas utilities on customers who reported that call center representatives were "very knowledgeable." One-in-seven customers found UGI Gas representatives to be less than "very knowledgeable." Whether it is responding to a collection call, enrolling in a universal service program, or some other customer service issue, having very knowledgeable customer service representatives is key to good customer service.

- UGI Gas ranked next to last (ahead of only PGW) in customer satisfaction with the "overall quality of service" during a recent contact. Nearly one-in-five (18%) of customers reported being less than "very satisfied" during their recent contact.

- UGI Gas customers ranked the Company below the statewide average for customer satisfaction with respect to credit and collection calls. UGI Gas's ranking was higher than NFG, and tied with PGW, but otherwise lower than average.

- UGI ranked last among Pennsylvania natural gas utilities on overall customer satisfaction with the way a premise visit was handled. Even when considering those customers who were only "somewhat satisfied," UGI customers reported satisfaction with premise visits in only 87% of the cases.

- UGI ranked last among Pennsylvania natural gas utilities on satisfaction that premise visit work was "completed promptly." Even when including "somewhat satisfied," nearly one-in-five UGI Gas customers (17%) were less than satisfied that premise visit work was completed promptly.

[25] Available at https://www.puc.pa.gov/filing-resources/reports/customer-service-performance-reports/ (last accessed April 8, 20220.

A review of the customer service performance reveals that UGI Gas does not perform at the top of Pennsylvania utilities. Its customer satisfaction does not support an upward adjustment in the return on equity.

Q. HAVE YOU REVIEWED CUSTOMER SERVICE AS IT RELATES TO UGI GAS?

A. Yes. Using the same BCS annual report as I discussed immediately above, I find that UGI Gas had far more instances where it did not respond to a residential dispute within 30 days. In 2020, UGI Gas had 156 instances where it did not respond to a dispute within 30 days. The Company asserted that this was a result of COVID19 restrictions. However, the next highest gas utility (NFG) had only four (4) instances where it did not respond within 30 days. Moreover, 2018 data (before COVID-19), shows that the 298 instances where UGI Gas did not respond to a residential dispute within 30 days was highest among the natural gas utilities. The next highest was PGW, which had only 61 instances of not responding within 30 days.

In addition to the BCS Customer Service Performance Report, I reviewed the most recent "Quarterly Update to UCARE Report."[26] The fourth quarter update of each year includes January through December (i.e., complete year) data. The Fourth Quarter report for 2020 is the most recent Fourth Quarter report available. (The Fourth Quarter 2021 report is not yet available.) The Fourth Quarter (2020) UCARE report documents that:

[26] Available at https://www.puc.pa.gov/filing-resources/reports/consumer-activities-report-evaluation/ (last accessed April 8, 2021).

- In 2019 (with some utilities not reporting 2020 data), UGI Gas (including UGI Penn Natural) has more residential complaints which BCS found “needs more investigation” than any other natural gas utility other than PGW.

- In 2019, UGI Gas (including UGI Penn Natural) had more residential Payment Arrangement Requests (PARs) that BCS found “need further investigation” than any utility other than PGW.

- In 2020, UGI Gas had a higher percent of customer complaints that BCS found to be “justified” than any other gas utility other than PGW.

- In 2020, UGI Gas had a higher percent of PARs that BCS found to be “justified” than any other gas utility other than Peoples.

- In 2020, UGI had 19 “verified infractions,” higher than every other natural gas utility other than PGW. The next highest natural gas utility was Peoples, with two (2) verified infractions.

According to BCS, a “justified consumer complaint” is one where “prior to BCS intervention, the company did not comply with commissions Orders, policies, regulations, reports, Secretarial Letters, tariffs, or guidelines when the consumer brought the complaint to the company’s attention.” A “justified PAR” is one where “prior to BCS intervention, the company did not comply with Commission regulations, reports, Secretarial Letters, tariffs or guidelines.”

Q. HAVE YOU REVIEWED UNIVERSAL SERVICE ACTIVITIES AS THEY RELATE TO UGI GAS?

A. Yes. In reviewing universal service performance, I reviewed the most recent BCS annual report on Universal Service Programs and Credit and Collections. The 2020 annual report is the most recent report available. I have discussed this 2020 BCS report in a number of instances throughout my testimony. The 2020 BCS report documents that:

- UGI is tied with NFG as the gas utility with the second lowest percentage of Confirmed Low-Income customers (as a percentage of estimated low-income customers). Only PECO Gas has confirmed the low income status of a lower percentage of its estimated number of low-income customers.

- UGI South has the highest total percentage of Confirmed Low-Income customers in debt (37.4%), more than twice as high as the statewide average Confirmed Low-Income customers in debt (17.5%). UGI North has the third highest percentage (33.6%), just somewhat lower than NFG who has the second highest (35.6%).

- UGI South (24.8%) and UGI North (20.3%) have the highest and second highest percentage of billings in debt for Confirmed Low-Income customers. Both UGI utilities are at or near two times the statewide average percentage of Confirmed Low-Income billings in debt (statewide average is 11.0%). The next highest percentage after UGI North is NFG, at 14.6% of its Confirmed Low-Income billings in debt.

- UGI's poor collections performance achieved through its universal service programs occurs notwithstanding the fact that it spends more on total residential collection costs than any other Pennsylvania natural gas utility. The UGI Gas expenditure of $4,599,633 is higher than the next highest utility (Peoples: $3,240,421). In addition to spending more on total residential collections, UGI spends a higher percentage of its residential collection costs on its Confirmed Low-Income customers (48.1%). This percentage is 50% higher than the statewide average percentage of total collection costs devoted to Confirmed Low-Income customers (31.2%), and far higher than the utility that has the next highest percentage (NFG = 38.8%).

- UGI, by far, enrolls the lowest percentage of its Confirmed Low-Income customers in its CAP (17.8%). The UGI Gas percentage of CAP enrollees of Confirmed Low-Income customers is roughly half that of the Pennsylvania natural gas utilities statewide (32.8%) and noticeably lower than the gas utility with the next highest percentage (NFG: 20.7%). If UGI Gas were to be excluded from the calculation of the statewide average, the statewide average CAP enrollment of Confirmed Low-Income would be 36.0%.

In addition to these findings, I have explained in detail above my findings with respect to UGI Gas under-performance regarding three universal service Outcome Objectives.

Q. WHAT DO YOU CONCLUDE?

A. In my testimony above, I reviewed whether UGI Gas has engaged in exemplary management in the areas of customer satisfaction, customer service, and universal service. I conclude that UGI Gas, at best, under-performs relative to Pennsylvania's natural gas utilities rather than in an exemplary fashion. UGI Gas has not manifested any particular "excellence" in management that would support an upward adjustment in its return on equity.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Appendix: Colton Abbreviated Vitae

Roger Colton
Fisher, Sheehan & Colton
Public Finance and General Economics
Belmont, MA
*** ***

EDUCATION:

J.D. (Order of the Coif), University of Florida (1981)

M.A. (Regulatory Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975) (journalism, political science, speech)

PROFESSIONAL EXPERIENCE:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 - present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including: regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than three dozen states. He is particularly noted for creative program design and implementation within tight budget constraints.

PROFESSIONAL AFFILIATIONS:

Past Chair:	Belmont Zoning By-law Review Working Committee (climate change)
Member:	Board of Directors, Massachusetts Rivers Alliance
Columnist:	Belmont Citizen-Herald
Producer:	Belmont Media Center: BMC Podcast Network
Host:	Belmont Media Center: Belmont Journal
Member:	Belmont Town Meeting
Vice-chair:	Belmont Light General Manager Screening Committee
Past Chair:	Belmont Goes Solar
Coordinator:	BelmontBudget.org (Belmont's Community Budget Forum)
Coordinator:	Belmont Affordable Shelter Fund (BASF)

Past Chair: Belmont Solar Initiative Oversight Committee
Past Member: City of Detroit Blue Ribbon Panel on Water Affordability
Past Chair: Belmont Energy Committee
Member: Massachusetts Municipal Energy Group (Mass Municipal Association)
Past Chair: Housing Work Group, Belmont (MA) Comprehensive Planning Process
Past Chair: Board of Directors, Belmont Housing Trust, Inc.
Past Chair: Waverley Square Fire Station Re-use Study Committee (Belmont MA)
Past Member: Belmont (MA) Energy and Facilities Work Group
Past Member: Belmont (MA) Uplands Advisory Committee
Past Member: Advisory Board: Fair Housing Center of Greater Boston.
Past Chair: Fair Housing Committee, Town of Belmont (MA)
Past Member: Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member: Board of Directors, Vermont Energy Investment Corporation.
Past Member: Board of Directors, National Fuel Funds Network
Past Member: Board of Directors, Affordable Comfort, Inc.
Past Member: National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member: Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member: ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member: National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member: National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

PROFESSIONAL ASSOCIATIONS:

National Association of Housing and Redevelopment Officials (NAHRO)
National Society of Newspaper Columnists (NSNC)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)
Association for Social Economics

BOOKS

Colton, *et al*., ***Access to Utility Service***, National Consumer Law Center: Boston (4th edition 2008).

Colton, *et al*., ***Tenants' Rights to Utility Service***, National Consumer Law Center: Boston (1994).

Colton, ***The Regulation of Rural Electric Cooperatives***, National Consumer Law Center: Boston (1992).

BOOK CHAPTERS

Colton (2018). The equities of efficiency: distributing energy usage reduction dollars, Chapter in Energy Justice: US and International Perspectives (Edited by Raya Salter, Carmen Gonzalez and Elizabeth Ann Kronk Warner), Edward Elgar Publishing (London, England).

JOURNAL PUBLICATIONS

65 publications in industry and academic journals, primarily involving utility regulation and affordable housing. (list available upon request)

TECHNICAL REPORTS

200 technical reports for public-sector and private-sector clients (list available upon request)

JURISDICTIONS IN WHICH EXPERT WITNESS PROVIDED

1. Maine
2. New Hampshire
3. Vermont
4. Massachusetts
5. Massachusetts
6. Rhode Island
7. Connecticut
8. New Jersey
9. Maryland
10. Pennsylvania
11. Washington D.C.
12. Virginia
13. North Carolina
14. South Carolina
15. Florida (Federal Court)
16. Alabama
17. Mississippi
18. Tennessee
19. Kentucky
20. Ohio
21. Indiana
22. Michigan
23. Wisconsin
24. Illinois
25. Minnesota
26. Iowa
27. Missouri
28. Arkansas
29. Texas (Federal Court)
30. South Dakota
31. North Dakota
32. Montana
33. Colorado
34. New Mexico
35. Arizona
36. Utah
37. Idaho
38. Nevada
39. Washington
40. Oregon
41. California
42. Hawaii
43. Kansas

Canadian Provinces

1. Nova Scotia
2. Ontario
3. Manitoba
4. British Columbia

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 4, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: April 20, 2022
*327281

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement 2R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	
v.	Docket No. R-2021-3030218
UGI Utilities, Inc. – Gas Division	

REBUTTAL TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 17, 2022

Q. Please state your name and business address.

A. My name is David J. Garrett. My business address is 101 Park Avenue, Suite 1125, Oklahoma Company, Oklahoma 73102.

Q. By whom are you employed and in what capacity?

A. I am the managing member of Resolve Utility Consulting, LLC. I am an independent consultant specializing in public utility regulation.

Q. Did you file direct testimony in this proceeding?

A. Yes. I filed direct testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"), in which I addressed the estimated cost of capital and awarded rate of return recommendation for UGI Utilities, Inc. – Gas Division ("UGI" or the "Company") in response to Company witness Paul R. Moul.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses the cost of equity estimates and authorized return on equity ("ROE") recommendation of Anthony Spadaccio, who testified on behalf of the Bureau of Investigation & Enforcement ("I&E").

Q. What issues are you responding to?

A. Specifically, I will address Mr. Spadaccio's growth rate inputs used in his Discounted Cash Flow ("DCF") Model and the Equity Risk Premium ("ERP") input used in his Capital Asset Pricing Model ("CAPM"). To the extent I do not specifically address an issue raised in Mr. Spadaccio's testimony, it does not constitute my agreement with such issue.

Q. Please summarize Mr. Spadaccio's authorized ROE recommendation and compare it with your recommendation.

A. Mr. Spadaccio proposes an authorized ROE of 9.92% for UGI,[1] which is notably higher than my proposed ROE of 8.5%.

Q. Please summarize the results of Mr. Spadaccio's DCF Model.

A. Mr. Spadaccio's DCF cost of equity estimate is 9.92%, which equates to his overall ROE recommendation.[2] In contrast, my DCF cost of equity estimate for UGI is 6.7%.

Q. Do you agree with the results of Mr. Spadaccio's DCF Model?

A. No. A cost of equity estimate over 9% for UGI is unreasonably high under current market conditions. The results of Mr. Spadaccio's DCF Model are unreasonably high due to his assumptions about long-term growth. As discussed in my direct testimony, the growth rate input is the most important input in the DCF Model. Mr. Spadaccio relied on short-term growth rate inputs for the long-term growth rate input in his DCF Model, which has resulted in unsustainable long-term growth rate estimates.[3] Specifically, he relied on five-year growth rate projections.[4] Furthermore, his growth rate projections are as high as 10.5%,[5] which is more than twice as high as projected U.S. GDP growth (about 3.8%).[6] Even Mr. Spadaccio's average long-term growth rate input of 6.53% is not sustainable for the same reason.

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[1] Direct Testimony of Anthony Spadaccio, p. 5.

[2] *Id*. at p. 22.

[3] The concern over the use of short-term growth rates is discussed in detail in my direct testimony at pp. 30-42.

[4] *Id*. at p. 21, lines 5-8.

[5] I&E Exh. No. 2, Sch. 5.

[6] Exhibit DJG-5.

In my opinion, there are several problems with using analysts' growth rates in the DCF to measure utility cost of equity. First, analysts' growth rates are short-term growth rates. A company might be able to increase earnings by 10% each year for the next several years, but it is essentially impossible to do that year after year for decades into the future. Furthermore, even if a utility could maintain a 10% annual growth in earnings (presumably due to excessive, regular rate increases), we have a circular reference problem to the extent the regulator is relying on the growth rates they helped produced (and that would be noted by the commercial analyst) to measure a metric (the ROE) that will in turn have a heavy influence on earnings. For these reasons, it is reasonable to look at GDP as a constraint on long-term growth, and it is a factor that avoids the circular reference problem of short-term analysts' growth rates.

Q. Are there other reasons why GDP should be viewed as a limiting factor on long-term growth for individual companies?

A. Yes. It is a fundamental concept that no company’s earnings can grow at a greater rate than the economy in which it operates. If this were not true, then the earnings of a particular company could eventually exceed GDP, which is not a reasonable assumption. As stated by Dr. Damodaran: “[i]f a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value.”[7] Thus, Mr. Spadaccio’s short-term growth rate inputs are unreasonably high, which results in a DCF cost of equity estimate that is also unreasonably high.

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[7] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

Q. Please summarize the results of Mr. Spadaccio's CAPM.

A. Mr. Spadaccio's CAPM produced a cost of equity estimate of 12.13%.[8] This result is considerably higher than my CAPM cost of equity estimate of 7.2%.

Q. Do you agree with the results of Mr. Spadaccio's CAPM?

A. No. A cost of equity estimate over 12% is unreasonably high for UGI. Mr. Spadaccio's CAPM is overestimated primarily due to his assumed ERP. The ERP is arguably the single most important metric used by financial analysts to assess market risk and cost of equity. The ERP is essentially the level of return investors expect above the risk-free rate in exchange for investing in risky securities; it is the required return on the entire equity market, minus the risk-free rate. Mr. Spadaccio estimates an ERP of 11.64%, which includes an expected return on the overall market of 13.99%.[9]

Q. How does Mr. Spadaccio's ERP estimate compare with your ERP estimate and the estimate of other experts?

A. As discussed in my testimony, I considered the ERP reported in expert surveys, the ERP estimated by Duff & Phelps, the ERP estimated by Dr. Damodaran, and my own ERP estimate in determining a reasonable ERP input for my CAPM. The results are presented in the following figure:

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[8] Direct Testimony of Anthony Spadaccio, p. 25.

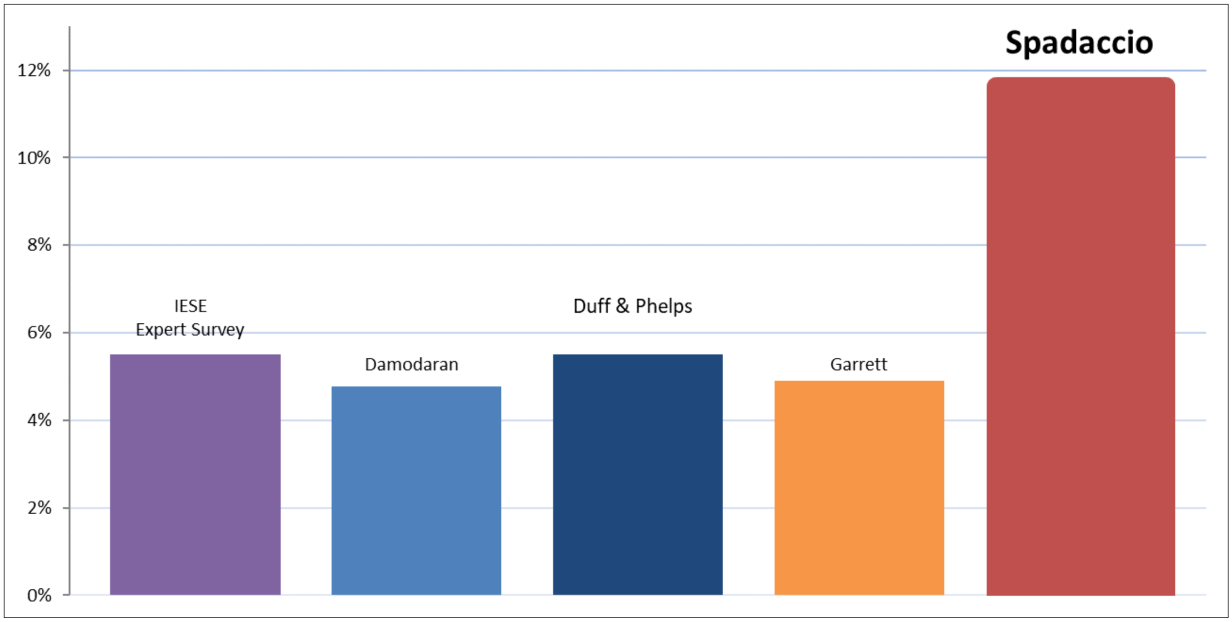
[9] *Id*.

Figure 1:
Equity Risk Premium Results

IESE Business School Survey	5.5%
Duff & Phelps Report	5.5%
Damodaran (average)	4.8%
Garrett	4.9%
Average	**5.2%**
Highest	**5.5%**

While it would be arguably reasonable to select any one of these ERP estimates to use in the CAPM, to be conservative, I selected the highest ERP estimate of 5.5% to use in my CAPM analysis. This means Mr. Spadaccio used an ERP that is more than twice as high as the highest ERP shown in this figure. The chart in the following figure illustrates that Mr. Spadaccio's ERP estimate is far out of line with other reasonable, objective estimates for the ERP.

Figure 2:
Equity Risk Premium Comparison



Because Mr. Spadaccio used an unreasonably high estimate for the ERP, his CAPM cost of equity estimate is overstated.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, David J. Garrett, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 2R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 17, 2022
*328710

Signature: ______________________
David J. Garrett

Consultant Address: Resolve Utility Consulting, PLLC
101 Park Avenue
Suite 1125
Oklahoma City, OK 73102

OCA Statement 3R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	Docket No. R-2021-3030218
UGI UTILITIES, INC. – GAS DIVISION	)	

REBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 17, 2022

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement 3 on April 20, 2022.

Q. WHA IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the cost allocation and rate design direct testimony of Ethan H. Cline submitted on behalf of the Bureau of Investigation and Enforcement ("I&E"), and Robert E. Knecht submitted on behalf of the Office of Small Business Advocate ("OSBA").

II. I&E WITNESS CLINE

Q. WHAT DID MR. CLINE RECOMMEND WITH RESPECT TO THE ALLOCATION OF THE RATE INCREASE TO EACH CUSTOMER CLASS IF THE COMMISSION GRANTS UGI GAS A RATE INCREASE THAT IS LESS THAN THE INCREASE REQUESTED BY UGI GAS?

A. Mr. Cline recommends that if the Commission grants UGI Utilities, Inc. – Gas Division ("UGI Gas" or "Company") a rate increase that is less than the increase initially requested by the Company, the allocation of the rate increase initially proposed by UGI

Gas for each class be proportionately scaled back to produce the revenue requirement authorized by the Commission.[1]

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The allocation of the rate increase to each customer class initially proposed by UGI Gas was based on the class cost-of-service study sponsored by UGI Gas. That cost-of-service study was prepared utilizing the Average & Excess ("A&E") method. As explained in my direct testimony and further explained in my subsequent response to OSBA witness Mr. Knecht, the A&E method produces study results that do not reasonably or responsibly allocate class costs of service.[2] The Peak & Average ("P&A") Study represented in my direct testimony reflects an allocation of costs consistent with Commission precedent and cost-of-service principles, and corrects other cost misallocations in the Company's study. Thus, a simple scale back – as proposed by I&E witness Cline -- is insufficient. Rather, the allocation of the revenue increase to each customer class should be guided by the results of the P&A Study. In my direct testimony I present such an allocation of the revenue increase initially requested by UGI Gas, and consistent with the recommendation in my direct testimony, those allocations should be proportionately scaled back to produce the revenue requirement authorized by the Commission.

III. <u>OSBA WITNESS KNECHT</u>

Q. IN HIS DIRECT TESTIMONY, MR. KNECHT DISCUSSES THREE COMMON METHODS TYPICALLY UTILIZED IN PENNSYLVANIA TO ALLOCATE MAINS COSTS IN A COST-OF-SERVICE STUDY WHICH

[1] See, I&E St. 4 at 27.
[2] See, OCA St. 3 at 22-23.

HE IDENTIFIES AS ALLOCATIONS BASED ON PEAK DEMAND, P&A DEMAND, AND A&E DEMAND. WHAT IS MR. KNECHT'S ASSESSMENT OF THE P&A METHOD?

A. Mr. Knecht correctly notes that, under the P&A method, mains costs are allocated based on a weighted mix of design day and average day demands.[3] However, he claims that the P&A approach is conceptually flawed because no mains cost are caused by average day demands, and if mains were sized to meet average day demands, gas customers would be without heat on the coldest days of the winter. He contends that a main sized to meet a demand of 100 Mcf per day costs the same whether that main is used to deliver 100 Mcf per day on every day of the year, or if that main only averages 20 Mcf per day over the course of the year.

Q. IS MR. KNECHT CORRECT THAT MAINS COSTS ARE NOT CAUSED BY AVERAGE DAY DEMANDS?

A. No. As explained in my direct testimony, with the exception of mains extensions up to 150 feet which is a recently adopted policy, and as set forth in Item 5 of the Rules and Regulations of the Company's tariff, anticipated annual customer usage, or average day demands, and the associated annual revenues, are the primary factor influencing UGI Gas' decisions to extend mains and make the associated investment to connect new customers to its distributions system.[4] Without sufficient annual gas usage over which to amortize the annual costs of providing service, there would be no UGI Gas distribution system. While UGI Gas may incur additional mains investment costs to meet demands in excess of average demands, those cost are significantly less than the costs of meeting annual demands. As demonstrated in my direct testimony, based on

[3] See, OSBA St. 1 at 8.
[4] See, OCA St. 3 at 16.

UGI Gas' actual main investment costs, meeting demands in excess of average demands can be accommodated at increased distribution mains costs that are approximately 10 percent of the costs of meeting average demands.[5]

Q. DOES MR. KNECHT CLAIM THAT THE COMMISSION HAS A STANDARD POLICY CONCERNING THE ALLOCATION OF MAINS COSTS?

A. No. Mr. Knecht claims that the Commission has indicated that it does not have a standard policy regarding the allocation of mains costs, and that the Commission intends to evaluate the issue on a case-by-case basis.[6] He notes that in 2021, the Commission approved the use of both the P&A and A&E methods. Mr. Knecht further notes that in the 2021 PECO Energy Company ("PECO") proceeding in which the Commission approved the use of the A&E method, the Commission "concluded that the excess demand component of PECO's distribution mains system garners considerable weight in the balance of mains costs."[7]

Q. WHAT IS YOUR RESPONSE TO THE COMMISSION'S FINDINGS IN THE PECO PROCEEDING WITH RESPECT TO THIS PROCEEDING?

A. As just explained, in this proceeding, I have demonstrated that on the UGI Gas system, meeting demands in excess of average demands can be accommodated at increased distribution mains costs that are approximately 10 percent of the costs of meeting average demands. Nevertheless, in the P&A cost-of-service study I present in this preceding, I have allocated 50% of mains costs based on peak demands. Therefore, I

[5] See, OCA St. 3 at 21-22.
[6] See, OSBA St. 1 at 8-9.
[7] Non-Proprietary Version, Opinions and Order, Docket No. R-2020-3018929, Order Entered June 22, 2021 ("PECO Order"), at 229.

have given considerable weight to the peak demand component of UGI Gas' distribution system.

Q. IN THE PECO PROCEEDING DISCUSSED BY MR. KNECHT, THE COMMISSION WAS PERSUADED BY PECO'S ARGUMENT THAT THE P&A METHOD IMPLICITLY DOUBLE COUNTS AVERAGE DEMANDS. PLEASE EXPLAIN THIS ARGUMENT.

A. P&A method uses a weighting 50% for the full peak demand which has a component of average daily usage (peak demand = average daily usage + excess demand), and a weighting of 50% on average daily usage. It has been argued that this method has the effect of weighting the average usage twice, once in the peak demand and once in average daily usage.

Q. WHAT IS YOUR RESPONSE TO THE DOUBLE COUNT CLAIM?

A. The double count claim is incorrect and misleading. Consider the following example. Customer A, a Residential customer, has a peak demand of 10 Mcf and an average demand of 4 Mcf. Customer B, an industrial customer, also has a peak demand of 10 Mcf, but an average demand of 8 Mcf. Under the P&A method, each customer would be allocated 50 percent of peak demand-related mains costs, as each customer's peak demand represents 50 percent of the total peak demand of 20 Mcf. Customer A would be allocated 33.3 percent (4/(4 + 8)) of annual demand-related mains costs and Customer B would be allocated 66.7 percent (8/(4 + 8)) of annual demand-related mains costs. Now assume the average demand of Customer A increases to 6. Under the P&A method, each customer would continue to be allocated 50 percent of peak demand-related mains costs, but the allocation of annual demand-related mains costs to Customer A would increase. The change in annual demand of Customer A has no effect on the allocation of peak demand-related costs and, therefore, there is no double-counting of annual usage.

Another way to demonstrate that the P&A method does not double-count annual demands is as follows. The allocation of the annual component of mains under the P&A method reflects average usage over a 365-day period. The peak day used to allocate the peak component of mains is theoretically supposed to reflect usage on one day during the year. To eliminate the alleged double-count, the annual average component of mains can be allocated based on average daily usage over a 364-day period. That is, the annual allocation would reflect average usage on every day except the peak day. Of course, a calculation of average daily use over a 364-day period will differ little from that computed over a 365-day period, so this hypothetical flaw in the P&A method would have no material impact on the cost of service study results.

Q. DID MR. KNECHT PROPOSE ANY CHANGES TO THE COMPANY'S PROPOSED ALLOCATION OF THE REVENUE INCREASE TO THE VARIOUS CUSTOMER CLASSES?

A. Mr. Knecht proposed two changes to the revenue allocation presented by the Company. First, he recommends that Rate XD and Rate IS not be assigned rate decreases. Second, he proposes decreasing the rate increase assigned to Rate N/NT and Rate LFD, and increasing the rate increase assigned to Rate R/RT and Rate DS.

Q. DO YOU AGREE WITH THE CUSTOMER CLASS REVENUE ALLOCATION MODIFICATIONS PROPOSED BY MR. KNECHT?

A. To some extent. I agree with Mr. Knecht that no customer class should receive a rate decrease. However, Mr. Knecht's proposed revenue allocation is based on the results of the Company's A&E cost of service study. As previously explained, the A&E

method produces results that do not reasonably reveal an accurate indication of class allocated cost responsibility and, therefore, Mr. Knecht's proposed revenue allocation should be rejected. I would note, however, that like Mr. Knecht, under my proposed revenue allocation, the increase to Rate N/NT has been reduced from that proposed by the Company, and the increase to Rate DS has been increased.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 3R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 17, 2022
*328709

Signature: Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement 4R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3030218
UGI Utilities – Gas Division	:	

Rebuttal Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement 4R

May 17, 2022

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED DIRECT TESTIMONY ON BEHALF OF THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR REBUTTAL TESTIMONY.

A. In my Rebuttal Testimony, I respond to the Consumer Input Hearing testimony of two different public witnesses: (1) Lisa Musser (April 13, 2022 1:05 p.m. public input hearing, at Tr. 22 – 25); and (2) Ruth Weaver (April 13, 2022 1:05 p.m. public input hearing, at Tr. 46 – 47). I limit my response to statements of fact provided by each public input witness, rather than responding to expressions of opinion.

Q. WHAT PUBLIC HEARING TESTIMONY OF MS. MUSSER DO YOU WISH TO RESPOND TO?

A. Ms. Musser expressed concerns about the affordability of UGI bills to her family. She further expressed concerns about her family's inability to control its bills through concerted efforts to reduce usage. According to Ms. Musser:

> In January of 2021, my family used 254 CCF and our bill was $231. In January of this year, we turned down the heat and we used 218 CCF, and our bill was $263. So, we used 36 less CCF, but our bill was $32 more than the previous year. In March of '21, my family used 286 CCF and the bill was $264. This year, we used 232 CCF due to turning the heat down often and our bill was $279. So this March, we froze to lower our bill, used 54 less CCF than [last] year, and our bill was ten more dollars. I

> cannot imagine what our bill would have been if we didn't freeze half the winter. How would we have afforded to pay it? I am constantly chasing after my children saying things like put your slippers back on, go get socks on your feet, put a hoodie on, it's not that cold in here and go grab a blanket. I cannot imagine what it is doing to people in our community who live in poverty.

(04-13-22 PIH Tr., at 23 – 24).

Q. WHAT IS YOUR RESPONSE TO MS. MUSSER'S PUBLIC HEARING TESTIMONY?

A. Ms. Musser's testimony affirms and expands upon the information I provided in my Direct Testimony through her direct, personal experience. My Direct Testimony stated in relevant part that one problem with the UGI Gas proposed rate hike "is associated with the increased fixed monthly customer charge. The increased customer charge is an unavoidable fixed monthly fee. Even if low-income customers could reduce their usage, they would not be able to avoid any part of the proposed increase in the fixed monthly customer charge." (OCA St. 4, at 10). Ms. Musser explains in compelling detail, based on her personal experience, the accuracy of that observation. She explained how her family decreased usage, and yet her bill increased. She explained how her family decreased usage at considerable sacrifice to the family, and yet her bill for that decreased consumption increased. As she testified, "I cannot imagine what our bill would have been if we didn't freeze half the winter." (04-13-22 PIH Tr., at 24).

The payment difficulties identified in Ms. Musser's testimony should not be ignored. In the Fall of 2021, the U.S. Department of Energy (DOE) released its October 2021 "Short Term Energy Outlook." That October 2021 price projection stated in relevant part:[1]

> As we head into the winter of 2021–22, retail prices for energy are at or near multiyear highs in the United States. The high prices follow changes to energy supply and demand patterns in response to the COVID-19 pandemic. We expect that households across the United States will spend more on energy this winter compared with the past several winters because of these higher energy prices and because we assume a slightly colder winter than last year in much of the United States.
>
> Even when we vary weather expectations, we expect the increase in energy prices as the United States returns to economic growth to mean higher residential energy bills this winter:
>
> - We expect that the nearly half of U.S. households that heat primarily with natural gas will spend 30% more than they spent last winter on average—50% more if the winter is 10% colder-than-average and 22% more if the winter is 10% warmer-than-average."

Even though the Short Term Energy Outlook projected an increase in natural gas heating costs of between 30% and 50% for the winter of 2021 – 2022, many, if not most, analysts expected that fly-up in price to be a short-term anomaly. However, as we now know, with turmoil in world commodity markets, inflation, and war in Europe all driving higher consumer prices, energy prices are still increasing. Ms. Musser's concerns about the impact of adding an increase in distribution rates on top of these other price increases are well-founded.

Yet, while affirming my Direct Testimony, Ms. Musser's testimony also expanded upon my Direct Testimony. My Direct Testimony regarding the adverse impacts on "low-

[1] Available at: https://www.eia.gov/outlooks/steo/report/WinterFuels.php (last accessed May 9, 2022).

income" customers was directed toward customers with income sufficiently low that they might qualify for either CAP or LIHEAP. In contrast, Ms. Musser's testimony demonstrates how the concerns I express are applicable to those households who may have income sufficiently high to be no longer income-eligible for universal service programs such as CAP and LIHEAP, but is sufficiently low to be unable to afford their UGI Gas bill. Ms. Musser testified that "Those of us who don't qualify for LIHEAP should be able to by state standards afford our heating bills, but that is slowly becoming not the case with every increase that UGI requests." (Id., at 23). Referring to herself as "those of us who don't qualify for LIHEAP" indicates that the concern about unaffordability, as well as the concerns about the inability to reduce bills by reducing consumption, is not limited merely to those who fall below income-eligibility guidelines for programs such as CAP and LIHEAP. There is yet another population of families who face payment difficulties, and yet who do not qualify for assistance.

Q. WHAT PUBLIC HEARING TESTIMONY OF MS. WEAVER DO YOU WISH TO RESPOND TO?

A. Ms. Weaver expressed concern about the opportunities that are available to her to improve the affordability of her UGI Gas bill. According to Ms. Weaver's public hearing testimony:

> My complaint today is the weather normalization program UGI wants to implement. UGI offers a budget for those who choose to normalize their expenses. This program only benefits UGI by forcing me to pay more in the summer so their income is more equal year round.
>
> I do not want this program for the following reasons. My electric bills are higher in the summer. My lawn, garden and home maintenance expenses are higher in the summer. I do more in the summer which increases my expenses. School taxes are

> due in the summer. By forcing me in this program, you are taking away the extra money I have in the summer to do the things that I want and need to do.
>
> As a senior citizen I only get so much money per month and need to make it last. I can't ask the government to pay me more in the winter to put aside for the summer months when my expenses are higher.

(04-13-22 PIH Tr., at 46 – 47).

Q. WHAT IS YOUR RESPONSE TO MS. WEAVER'S PUBLIC HEARING TESTIMONY?

A. Ms. Weaver's testimony not only supports my Direct Testimony regarding the unreasonable impacts of the proposed increase in the fixed monthly customer charge, but also expands its reach.

In my Direct Testimony, I explain why, given that UGI Gas enrolls only 14% of its income-eligible population in CAP, "[W]e can deduce that at least 86% of UGI's estimated low-income customers are not paying a percentage of income-based CAP bill and, thus, are not insulated from the effects of the proposed increase in UGI's fixed monthly customer charge." (OCA St. 4, at 8). In contrast, Ms. Weaver identifies another population of customers with an inability to pay who "are not insulated from the effects of the proposed increase in UGI's fixed monthly customer charge." When asked by UGI Gas counsel, "Ms. Weaver, would you be all right if someone from the company reached out to you to see if you would qualify for any of the customer assistance programs," Ms. Weaver responded, "I'm not eligible." (04-13-22 PIH Tr., at 48).

In contrast, Ms. Weaver's testimony buttresses my Direct Testimony because she makes clear that her family's inability-to-pay involves no choice on her part. Rather, even though having income sufficiently high that she is "not eligible" for programs such as LIHEAP and CAP, she provides a detailed explanation, based on personal experience, of how she has an absolute mismatch between household income and her UGI Gas bill. The question to Ms. Weaver is not one of receiving a UGI Gas bill and making a payment, but rather a question of which bill gets paid this month.

As with the testimony of Ms. Musser, the testimony of Ms. Weaver identifies a population of customers who are not eligible for energy assistance programs such as LIHEAP or CAP, but who nonetheless have insufficient household resources to be able to pay their UGI Gas bills, even without any increase in the irreducible portion of the bill attributable to an increase in the fixed monthly customer charge. To customers such as Ms. Musser, the question is not one of levelizing her monthly bills. She states quite explicitly that "My electric bills are higher in the summer. My lawn, garden and home maintenance expenses are higher in the summer. I do more in the summer which increases my expenses. School taxes are due in the summer. By forcing me in this program, you are taking away the extra money I have in the summer to do the things that I want and need to do." (04-13-22 PIH Tr., at 48).

Q. DO YOU HAVE ANY CONCLUDING REMARKS ABOUT THE PUBLIC INPUT TESTIMONY OF MS. WEAVER AND MS. MUSSER?

A. Yes. Everything that both Ms. Weaver and Ms. Musser say about their difficulties as families with income that are sufficiently high to not qualify them for LIHEAP or CAP would be equally applicable to households with even lower incomes who *do* qualify for LIHEAP and CAP. Ms. Weaver's testimony, along with Ms. Musser's testimony, provide compelling personal real-life examples of the need for the Commission to adopt each recommendation set forth in my Direct Testimony.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Rebuttal Testimony, OCA Statement 4R, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 17, 2022
*328621

Signature: ______________________
Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Statement 1SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**)**	
v.	**)**	**Docket No. R-2021-3030218**
UGI Utilities, Inc. Gas Division	**)**	

SURREBUTTAL TESTIMONY OF

DANTE MUGRACE

ON BEHALF OF THE

PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE

<u>HIGHLY CONFIDENTIAL VERSION</u>

May 27, 2022

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I. PURPOSE OF SURREBUTTAL TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD 20877.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes. I submitted Direct Testimony on April 20, 2022, which was marked as OCA Statement 1. My qualifications and experience are attached to my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to address the Rebuttal Testimonies of Company witnesses Hazenstab (UGI Statement No. 2-R), Ressler (UGI Statement No. 3-R), Schappell (UGI Statement No. 5-R) and Angstadt Statement No. 9-R. I am also making certain adjustments to proposals in my testimony and a revised calculation of the Company's revenue requirement that incorporates the effects of my adjustments. I've also updated the Company's adjustments to certain of its revenue requirement schedules, as noted in the Company's UGI Gas Exhibit A FPFTY Rebuttal. To the extent that I do not respond to or address a particular issue or argument, I defer to my Direct Testimony on those issues.

Q. HAS THE COMPANY MADE ADJUSTMENTS TO ITS AS FILED PETITION WITH RESPECT TO ITS PROPOSED REVENUE REQUIREMENT?

A. Yes. As stated by Mr. Brown (UGI Statement No. 1-R), inflationary increases and other economic factors impacted the Company's operations as well as increased contractors' costs that resulted in an updated revenue requirement adjustment of $7.1 million (UGI Statement No. 1-R at 4). The overall effect of the updates and corrections to the Company's claim is that the Company has allegedly supported a revenue increase of $87,619,000 as compared to the as-filed claim of $82,742,000 using the Company's proposed capital structure, revised weighted average cost of debt and proposed return on equity of 11.20%. (UGI Statement No. 3-R at 6).

Q. WITH YOUR ADJUSTMENTS TO YOUR DIRECT TESTIMONY, WHAT IS YOUR REVISED COMPANY REVENUE REQUIREMENT?

A. With my revised adjustments, I have calculated a revenue requirement decrease of $24,754,635. This includes OCA Witness Mr. Garrett's overall rate of return of 6.24% which includes a common equity cost rate component of 8.50%.

II. REVENUE REQUIREMENT ISSUES

A. Rate Base Issues

1. Utility Plant In Service (UPIS)

Q. WHAT IS THE COMPANY'S POSITION REGARDING YOUR ADJUSTMENTS TO ITS UTILITY PLANT IN SERVICE?

A. Ms. Schappell did not agree with my adjustments related to the Company's Plant in Service Adjustment that were projected for the FTY and the FPFTY. (UGI Statement No. 5-R at 2). Ms. Schappell did not agree with my adjustment in removing plant in service totaling $85,681,967 (decrease for the FTY of $27,785,189 and a decrease for the FPFTY of $57,896,778). Ms. Schappell stated that I incorrectly identified the FPFTY period as ending in December 31, 2023, when it should have been September 30, 2023. (Id. at 3). Ms. Schappell stated that I was correct in part that the projects listed in my direct testimony will be placed in service after the end of the FPFTY. (Id.). Ms. Schappell stated that I misunderstood the Company's response to I&E RE-RB-4-D and that all of these budgeted projects for the FTY and the FPFTY were already excluded from the projected plant in service. The $85,681,967 that I recommended should be excluded is not appropriate as they were never included in the Company's filed claim. (UGI Statement No. 5-R at 3). Ms. Schappell stated that the Company reduced its plant in service balance by $700,846 as the Company inadvertently included some of these post-FPFTY projects. (Id. at 5).

Q. WHAT IS YOUR RESPONSE?

A. I did err in stating that the FPFTY period was December 31, 2023, it should have been September 30, 2023, however, this has no effect on my recommended adjustment balance for the FTY and the FPFTY period. I reviewed Ms. Schappell's Confidential UGI Gas

Exhibit VAS-1R in which Ms. Schappell demonstrated that the projects I excluded in the amount of $85,681,967 were already excluded. I did see where the Company made adjustments to record the plant additions claimed to not be included in Company Exhibit VAS-1R, In reviewing the Confidential response to I&E RB-4-D Supplemental the Company recorded **(BEGIN CONFIDENTIAL)** $452,496,0338 of FY 2022 Capital Budget additions and a net balance of $397,703,948 **(END CONFIDENTIAL)** which matches the Company's Schedule C-2. (UGI Gas Exhibit A FPFTY Rebuttal). The Company recorded **(BEGIN CONFIDENTIAL)** $469,839,637 of FY 2023 Capital Budget additions and a net balance of $476,426,821 **(END CONFIDENTIAL)** which matches the Company's Schedule C-2, (UGI Gas Exhibit A FPFTY Rebuttal). [1] The information provided by Ms. Schappell in UGI Confidential VAS-1R was not part of the discovery in response to I&E RB-4-D. In reviewing UGI Confidential VAS-1R, I was able to trace and track the approximate $85,681,000 of plant adjustments that the Company excluded from its capital budget projection. In sum, I am accepting the Company's response and information submitted with respect to the $85,681,967 of plant additions that were already excluded from the Company's plant in service balance.

2. Accumulated Depreciation

Q. WHAT DID MS. RESSLER STATE WITH RESPECT TO YOUR ADJUSTMENTS TO ACCUMULATED DEPRECIATION?

A. Ms. Ressler did not agree with my adjustments to the Company's Accumulated Depreciation Balance as she disagreed with my adjustments to the Company's Gas Plant in Service Balance. (Statement No. 3-R at 5).

Q. WHAT IS YOUR RESPONSE?

A. Given that I am accepting the Company's response to the $85,681,967 of plant additions, I am accepting the Company's balance to its Accumulated Depreciation. The Company

[1] Any differences are due to rounding.

has adjusted its Accumulated Depreciation by reducing it by $480,933 to reflect its updated adjustment to plant in service. (Statement No. 3-R at 5).

3. Accumulated Deferred Income Taxes

Q. WHAT DID MS. RESSLER STTE WITH RESPECT TO YOUR ADJUSTMENTS TO THE ACCUMULATED DEFERRED INCOME TAXES?

A. Ms. Ressler did not agree with my adjustments to the Company's Accumulated Deferred Income Taxes as she explained with her disagreements related to Accumulated Depreciation. (Statement No. 3-R at 6).

Q. WHAT IS YOUR RESPONSE?

A. Given that I am accepting the Company's claim on its Gas Plant In Service balance, specifically the plant additions for FY 2022 and FY 2023, I am recommending acceptance of the Company's Accumulated Deferred Income Taxes. The Company has adjusted its Accumulated Depreciation by reducing it by $85,000 to reflect its updated adjustment to plant in service. (Statement No. 3-R at 6).

4. Cash Working Capital

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S CASH WORKING CAPITAL?

A. Ms. Hazenstab stated that she did not agree with my adjustments to the extent that these adjustments relate to underlying expense or tax adjustments. (Statement No. 2-R at 17). Ms. Hazenstab stated that my Cash Working Capital adjustments are based solely on my recommended expense adjustments O&M expenses and payroll expense adjustments, the interest payments components to net plant in service, and the overall impact of all adjustments and a reduced revenue requirement which reduces income taxes. (Statement No. 2-R at 18-19).

Q. WHAT IS YOUR RESPONSE?

A. Ms. Hazenstab's statements regarding my adjustments to certain O&M expenses, payroll expenses, interest payments and the effect of a lower revenue requirement are correct. My

Cash Working Capital balance reflects all my adjustments to the Company's revenue requirement proposal, and those flow-through adjustments reflect the balance that I am recommending. I don't believe we are in disagreement with the methodology used to compute the Cash Working Capital, just the adjustments to the calculation of the overall balance.

B. OPERATING INCOME

1. Operating Revenues – Forfeited Discounts, Miscellaneous Revenues and Rent from Gas Properties

Q. WHAT HAS THE COMPANY STATED REGARDING YOUR ADJUSTMENT TO OPERATING REVENUE – FORFEITED DISCOUNTS, MISCELLANEOUS REVENUES AND RENT FROM PROPERTIES?

A. Ms. Hazenstab did not agree with my normalized three-year period adjustment for these Operating Revenues categories. (Statement No. 2-R at 7). Ms. Hazenstab stated that I showed a total balance in the FTY of $19,181,000 in my direct testimony but my revenue adjustment on my schedules total $10,181,000. (Statement No. 2-R at 7). Ms. Hazenstab stated that based upon monthly three-year averages of historical data for each revenue category that the Company prepared in its FTY and FPFTY revenue projections, the additional averaging of revenue is unnecessary. Ms. Hazenstab stated that my adjustments did not remove the Company's share of off-system sales (Statement No. 2-R at 8).

Q. WHAT IS YOUR RESPONSE?

A. I note that I did err in my direct testimony related to the total balance of $19,181,000 but included $10,181,000 in my schedules. This did not affect my revenue requirement calculation. I reviewed the responses to I&E RS-25, 26 and 27 and, based upon the responses, I am accepting the Company's position that these costs have been developed based upon monthly three-year averages of historical data for each revenue category. Therefore, I am accepting the Company's balances for these Operating Revenues categories. My adjustment is shown on my Schedule SR-DM-4.

2. OPERATION AND MAINTENANCE EXPENSES

a. Payroll Expense/Payroll Taxes/Vacancy Rate

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENTS TO PAYROLL EXPENSE?

A. Ms. Hazenstab agreed with my adjustment of $779,368 to payroll expense related to the exclusion of 17 open positions related to replacement for which candidates have yet been identified. (Statement No. 2-R at 13).

Q. WHAT IS YOUR RESPONSE?

A. Given that the Ms. Hazenstab has accepted my adjustments related to these 17 open positions, I have not further adjustments related to Payroll Expense. My adjustment is shown on my Schedule SR-DM-4 and 11.

Q. WHAT DID THE COMPANY STATED REGARDING YOUR ADJUSTMENT TO PAYROLL TAXES?

A. Ms. Hazanstab stated that she agreed with my adjustment to Payroll Taxes related to the reduction of the payroll expense of $779,000 for the exclusion of the 17 open positions but disagrees with my Payroll Tax adjustment for Incentive Compensation. (Statement No. 2-R at 15). Ms. Hazenstab referred to the rebuttal testimony of Ms. Ressler (Statement No. 3-R) for her disagreements, which I will address under the Incentive and Stock Compensation section of my surrebuttal.

b. Incentive Compensation Expense/Stock Compensation

Q. WHAT DID COMPANY WITNESS MS. RESSLER STATE REGARDING YOUR ADJUSTMENTS TO INCENTIVE COMPENSATION EXPENSE?

A. Ms. Ressler stated that she did not agree with my disallowance to recover the Company's incentive compensation programs. Ms. Ressler stated that the Company's incentive compensation is a component of its overall compensation program designed by management to offer a competitive package to attract and retain qualified employees. If the Company were to eliminate incentive compensation, it would need to increase another component of compensation in order to remain competitive in the employment market. (Statement No. 3-R at 22). Ms. Ressler stated that I incorrectly assumed that the

Company's O&M Expense claim included incentive compensation associated with the UNITE management incentive plan. (Statement No. 3-R at 22). Ms. Ressler stated that in response to I&E discovery requests as CONFIDENTIAL Attachments I&E RE-17.3 and I&E RE-17.4 which describe the Company's UNITE Project Milestone Incentive Plan, I argued that the incentive compensation costs contemplated by this plan are not included in the incentive compensation costs but subsequently recommended that the UNITE Management Incentive Plan budgeted amount of **(BEGIN CONFIDENTIAL)** $2,603,000 be disallowed **(END CONFIDENTIAL).**

Q. WHAT IS YOUR RESPONSE?

A. Ms. Ressler is correct that I stated that the UNITE Initiative does not include expenses related to incentive compensation. (OCA Statement No. 1 at 45). My adjustment is related to the response to Confidential I&E RE-17.2 and further explanation in response to I&E RE-18 which asked for a detailed explanation of the Company's claimed incentive compensation of $11,129,787 and how the budgeted amount was calculated. I may have mis-characterized my adjustment that related to the UNITE Project Milestone Incentive Plan and the Company may have misinterpreted the information requested, but nevertheless, my adjustment is related to the Company's Incentive Compensation Plan shown in the response to Confidential I&E RE-17.2 and fully explained by the Company in response to I&E RE-18. My recommendation to disallow the Management Incentive Plan of **(BEGIN CONFIDENTIAL)** $2,603,000 **(END CONFIDENTIAL)** is the same, which I explain in more detail in #3 below.

Q. WHAT DID MS. RESSLER STATE REGARDING A BREAKDOWN OF THE COMPANY'S INCENTIVE COMPENSATION AMOUNTS INCLUDED IN THIS CASE?

A. Ms. Ressler stated that the Company has included **(BEGIN CONFIDENTIAL)** $10,785,000 **(END CONFIDENTIAL)** of Incentive Compensation as shown on UGI Gas Exhibit VKR-5R Confidential. Ms. Ressler stated that this schedule agreed to a similar schedule provided in response to I&E RE-17.2 as part of the discovery request process with the exception of **(BEGIN CONFIDENTIAL)** $431,000 **(END CONFIDENTIAL)** of deferred compensation is excluded because the Company does not believe that the amount associated with this plan is appropriately defined as incentive compensation. (Statement No. 3-R at 24).

Q, WHAT IS YOUR RESPONSE?

A. Since I removed the amount related to SERP expenses of **(BEGIN CONFIDENTIAL)** $431,000 **(END CONFIDENTIAL)**, I do not have any further adjustments to Mr. Ressler updated response related to the Company's Incentive Compensation. However, I do not believe these SERP expenses should be recovered elsewhere in the Company's O&M Expenses. My argument for removal is shown under section 4 in this testimony– Executive Bonus Plan, Performance Stock Awards, Stock Options and SERP.

1. UGI Corporate Allocation

Q. WHAT DID MS. RESSLER STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S UGI CORPORATE ALLOCATION?

A. Ms. Ressler did not agree with my disallowance of the Company's **(BEGIN CONFIDENTIAL)** $6,213,000 **(END CONFIDENTIAL)** in incentive compensation expense that was allocated to UGI Gas from UGI Corporation. (Statement No. 3-R at 24). Ms. Ressler stated that my disallowance was connected to the UNITE bonus program document and was not relevant to UGI Corporate Allocation costs to UGI Gas. (Statement No. 3-R at 25). Ms. Ressler stated that the Company was allocated **(BEGIN CONFIDENTIAL)** $2.185 million for incentive compensation, $3.472 million to stock options and restricted stock awards and $555,000 related to equity compensation for directors **(END CONFIDENTIAL)**. (Statement No. 3-R at 25).

Q. WHAT INFORMATION DID MS. RESSLER PROVIDE TO SUPPORT THE COMPANY'S UGI CORPORATE ALLOCATION RELATED TO INCENTIVE COMPENSATION?

A. Ms. Ressler stated that the incentive compensation is awarded to UGI Corporation employees and executives based upon performance under plans which establish financial and non-financial targets. The non-financial targets are related to safety for non-executive employees and, for executives, the non-financial targets are related to safety and diversity and are shown on Confidential UGI Gas Exhibit VKR-6R. (Statement No. 3-R at 25-26). Ms. Ressler stated that the stock and restricted stock awards were provided to employees based upon employee agreements and / or management discretion. The overall compensation policies and programs for executives are established by the Compensation and Management Development Committee of the Board of Directors of UGI Corporation. The program is designed to attract and retain talented and experienced executives and to reward them for leadership excellence. (Statement No. 3-R at 26). Ms. Ressler referred to Exhibit VKR-7R related to directors' compensation which are provided with long-term equity rewards in accordance with the director compensation program overseen by the Corporate Governance Committee and the Board of Directors as a whole. Ms. Ressler stated that the Company believes these plans are like in kind with executive and director compensation that the Commission has consistently allowed to be recovered in base rates for decades. (Statement No. 3-R at 26). Ms. Ressler stated that without these plans and the incentives that they provide, the Company could lose the executives or be required to simply increase their base salaries to compensate for the loss of the plan. (Statement No. 3-R at 26).

Q. WHAT IS YOUR RESPONSE?

A. Ms. Ressler information to support the Company's UGI Corporate Allocation is new information which was not provided in discovery. In response to OCA Set III-1, I asked for information related to Incentive Bonuses and confidential information. In response to OCA Set VII-13, I asked for information related to Stock Compensation expenses. In response to OCA-Set III-1, the Company provided information on increasing salaries for workers, compensation surveys and compensation adjustments which did not include information related to incentive compensation. In response to OCA-VII-13, I asked for information related to Stock Compensation, and the response referred to I&E RE-17.2 and all stock compensation expense can be found in Book V, Exhibit A Schedule B-4 FERC 920.0 Administrative Salaries. I did not receive any information (through discovery) related to what has been contained in UGI Gas Exhibit VKR-6R, nor what has been contained in UGI Gas Exhibit VKR-7R (which was not attached to Ms. Ressler's rebuttal testimony). Nevertheless, I believe that these costs should not be included in the Company's O&M Expense. While I understand the importance of providing incentive compensation to employees, I do not believe that certain areas of Executive incentive compensation—that do not provide specific benefits to customers—should be recoverable from ratepayers. In Ms. Ressler's Confidential Exhibit VKR-6R the Company has not provided the dollar amounts associated with safety, only the performance target/threshold goals, so I am unable to fully evaluate the reasonableness of the Company's claim for incentive Compensation. The Company has not provided Confidential Exhibit VKR-7R, so I am unable to evaluate what is contained in that Exhibit. In sum, part of the Company's argument in recovering incentive compensation is that it has to incentivize employees to perform their duties, to retain and attract talented and experienced executives, and to reward them for leadership excellence. While I agree that incentive compensation is embedded in all major companies' compensation package, I believe that incentive compensation related to executive management should be paid out by the shareholders of the Company and not by the ratepayers, since these types of incentive compensation has no impact on customer service or on customers.

2. UGI Gas Utility Incentive Compensation

Q. WHAT HAS MS. RESSLER STATED WITH RESPECT TO YOUR ADJUSTMENTS RELATED TO UGI'S GAS UTILITY INCENTIVE COMPENSATION?

A. Ms. Ressler did not agree with my adjustment to remove these costs. (Statement No. 3-R at 27). Ms. Ressler stated that my attempt to evaluate individual aspects of the Company's incentive compensation program in isolation should be rejected. Ms. Ressler stated that the Commission has previously rejected proposed adjustments to other utilities' claims for incentive compensation including stock-based compensation. (Statement No. 3-R at 28). She stated that the Commission made clear that incentive compensation programs must be evaluated as a whole when determining whether the plan includes goals which benefit customers. Ms. Ressler stated that breaking apart the Company's incentive compensation program into individual components inappropriately tries to single out individual aspects of the Company's total incentive compensation program, when as a whole, the program clearly contains both financial and operating metrics and goals which benefit customers, consistent with the Commission's Order in 2018 UGI Electric base rate proceeding. (Statement No. 3-R at 28-29).

Q. WHAT HAS MS. RESSLER STATED WITH RESPECT TO RECOVERY OF STOCK AWARDS AND STOCK OPTIONS?

A. Ms. Ressler stated that the Company must have access to capital in order to invest in the infrastructure necessary to provide safe and reliable natural gas service to its ratepayers. The achievement of financial goals makes investment in the Company's stock an attractive option to investors, thereby allowing access to this necessary capital and therefore, it is appropriate for ratepayers to bear the cost of these incentive compensation programs just as they bear other costs of the Company from which they directly or indirectly benefit. (Statement No. 3-R at 29).

Q. WHAT IS YOUR RESPONSE?

A. I do not believe that ratepayers should be burdened with costs related to the access of capital markets and to have the Company be attractive to investors to access capital markets. This is a business decision, and the business risks should lie with the Company. The customers do not have that decision-making ability nor has the Company asked the customers to do so. I believe this is the responsibility of the shareholders. Ratepayers should not be 100% responsible for the actions that relate to financial goals or business risks. In reviewing Ms. Ressler's UGI Gas Exhibit VKR-7R, I am still of the opinion that these types of incentive costs do not provide benefits to ratepayers.

Q. WHAT DID MS. RESSLER STATE REGARDING YOUR INQUIRY ON THE RECEIPT AND TIMING OF INCENTIVE COMPENSATION PAYOUTS?

A. Ms. Ressler stated that my assertion that the receipt and timing of incentive compensation is an impossible test to meet for any utility that seeks to recover projected incentive compensation expense for the FPFTY because incentive compensation is paid out based upon satisfaction of performance standards during the FPFTY. Ms. Ressler stated that my proposal for recovery of an expense should be rejected. Ms. Ressler stated that it is reasonably certain that the Company's incentive compensation program, as a whole, is necessary to attract and retain qualified employees. (Statement No. 3-R at 30).

Q. WHAT IS YOUR RESPONSE?

A. In order to recover costs, the Company has the burden of proof that the costs are both known and measurable as well as prudent. The Company claimed that it seeks to recover projected incentive compensation and that it is reasonably certain that the Company's incentive compensation program, as a whole, is necessary to attract and retain qualified employees. Without certainty, or a definitive level of known and measurable costs related to incentive compensation, it is unreasonable for the Company to expect all recovery of costs that it will assume to be incurred. If the Company includes all projected costs related to incentive compensation and subsequently does not pay out all of the projected incentive compensation, due to certain performance metrics and goals not being met by employees, it would be difficult to recover these costs back to ratepayers. The Company's all or nothing approach is not appropriate way to evaluate compensation, as it is an unrealistic approach.

3. UGI Gas MIP

Q. WHAT HAS MS. RESSLER STATED REGARDING YOUR ADJUSTMENT RELATED TO THE UGI GAS MANAGEMENT INCENTIVE PROGRAM (MIP)?

A. Ms. Ressler reiterated that my adjustment to remove **(BEGIN CONFIDENTIAL)** $2,603,000 of MIP costs **(END CONFIDENTIAL)** should be disallowed in that I associated these costs with the Company's UNITE incentive program. (Statement No. 3-R at 31).

Q. WHAT IS YOUR RESPONSE?

A. Regardless of whether these costs are related to the Company's UNITE Management Incentive Program or another management incentive program, I relied on the response to I&E RE-18 which shows the Company's claimed incentive compensation expenses of $11,129,787 and an explanation of how the budgeted amount was calculated.

Q. WHAT DID MS. RESSLER STATE RELATED TO THE COMPANY'S MIP?

A. Ms. Ressler stated that the Company's MIP is an annual incentive program for which regular full-time employees at career levels between M1-M6 and between P2-P5 are eligible. The goals included in the plan span a wide range of areas including financial performance, safety, reliability, customer satisfaction, business growth, sustainability and capital deployment (Statement No. 3-R at 31). Ms. Ressler stated that ratepayers benefit directly when the Company provides safe and reliable natural gas service and when its customer service is responsive to customer needs. (Statement No. 3-R at 32).

Q. WHAT IS YOUR RESPONSE?

A. UGI Gas Exhibit VKR-8R is new information provided by the Company in its rebuttal testimony; it was not provided in discovery where I asked for this information in response to OCA Set III-1. While I will accept incentive compensation that relates to ratepayer benefits such as safety and reliability, customer service and customer satisfaction, I am unable to evaluate dollar amounts associated with these performance goals. The Company has not included such costs in VKR-8R but only included weights and metrics shown on page 4. Given that the information related to these metrics, as well as other information needed to evaluate the level of incentive compensation the Company is proposing to include in rates, and the fact that certain information has been redacted, I am unable to ascertain or determine the reasonableness of any dollar amount associated with certain performance and targeted goals.

4. Executive Bonus Plan, Performance Restricted Stock Awards, Stock Options and SERP

Q. WHAT HAS MS. RESSLER STATED WITH RESPECT TO YOUR ADJUSTMENTS FOR EXECUTIVE BONUS, PERFORMANCE RESTRICTED STOCK AWARDS, STOCK OPTIONS AND SERP?

A. Ms. Ressler stated that she does not agree with my adjustments to remove **(BEGIN CONFIDENTIAL)** $2,312,000 **(END CONFIDENTIAL)** associated with each of these incentive compensation programs. (Statement No. 3-R at 32-33). Mr. Ressler stated that I do not understand how each of these programs benefits ratepayers and play an essential role in the Company's ability to provide the compensation necessary to attract and retain qualified employees that provide safe, efficient and reliable natural gas service. Ms. Ressler reiterated that I am singling out one aspect of the Company's overall compensation strategy for disallowance. (Statement No. 3-R at 33).

Q. WHAT DID MS. RESSLER STATE AS TO THE NEED FOR THE EXECUTIVE BONUS PLAN?

A. Ms. Ressler stated that these plans applied to executives of the UGI Utilities business and rewards these executives for meeting financial, safety and diversity goals. These goals are specific to the Earning Before Income Taxes (EBIT). Ms. Ressler stated that ratepayers benefit from the safety performance plan metric and the diversity initiative incentive which considers diversity in hiring practices. (Statement No. 3-R at 34).

Q. WHAT IS YOUR RESPONSE?

A. Ratepayers should not shoulder the burden to pay for costs of executive retainment. This is a business decision and the Company should bear the responsibility of paying for these costs of executive retainment. I do not see a nexus between executive retainment and ratepayer benefits. In response to VKR-8R, I am unable to evaluate the benefits related to safety and diversity goals as the Company did not provide any dollar amount associated with these goals. I do not believe that ratepayers should pay for incentive related goals for financial performance (EBIT) as these promote Shareholder interests and the alignment of Shareholder growth. These performance goals should be funded through Shareholder dollars and not ratepayer dollars.

Q. WHAT DID MS. RESSLER STATE AS TO THE NEED FOR PERFORMANCE RESTRICTED STOCK AWARDS AND STOCK OPTIONS?

A. Ms. Ressler stated that these awards are based upon employment contracts and management discretion, and awards are granted to employees and have a vesting period of three-years. Ms. Ressler stated that these awards and stock options benefit ratepayers by incentivizing key employees to maintain tenure with the Company through the vesting period. (Statement No. 3-R at 34-35). If the Company were to eliminate its equity compensation it would need to increase base pay by at least the same amount in order to remain competitive in the employment marketplace for talented executive – level employees. (Statement No. 3-R at 35).

Q. WHAT IS YOUR RESPONSE?

A. Ratepayers should not be responsible for pay for executive level employees to be retained by the Company. I believe it is the responsibility of the Company to provide these funding dollars. I do not see a nexus between stock awards and stock options and providing safe efficient and reliable service to customers.

Q. WHAT DID MS. RESSLER STATE REGARDING THE RECOVERY OF SERP?

A. Ms. Ressler stated that the SERP (Supplemental Executive Retirement Plan) is designed to provide retirement benefits for executive-level employees who are not eligible to receive the full typical Company contribution within its pension or 401 (k) program. Current (not retired) executives who earn more than the cap for the regular pension or 401 (k) plan are eligible for SERP. (Statement No. 3-R at 35). Ms. Ressler stated that if the SERP were excluded, the Company would need to increase base salary or other compensation in order to remain competitive for talented executives. The Company's SERP has existed for many years and has not been challenged in its rate proceedings. (Statement No. 3-R at 35-36).

Q. WHAT IS YOUR RESPONSE?

A. As I stated previously regarding the disallowance of stock awards and stock options for the retainment and to be competitive in the industry for talent, I believe that the Company should be responsible for covering these types of costs, not ratepayers. As Ms. Ressler stated, SERP has no goals or criteria to be met, and therefore, is a business decision on the Company, and the responsibilities should lie with Company to fund these costs.

Q. WHAT DID MS. RESSLER STATE REGARDING YOUR REMOVAL OF THE COMPANY'S $38,000 AND $51,000 OF INCENTIVE COMPENSATION FOR CETAIN OF THE COMPANY EMPLOYEES?

A. Ms. Ressler did not agree with my disallowance related to these incentive compensation claims. Ms. Ressler stated that the Company has clear performance goals, but the Company cannot yet know the final outcome of the performance goals for the FY 2023 period because the Company's case is based on a FPFTY. Based upon past performance, the Company believes that it is reasonable to assume that these goals will be achieved in order to earn a payout on the incentive compensation plan. (Statement No. 3-R at 37).

Q. WHAT IS YOUR RESPONSE?

A. As I stated earlier, in order to recover costs, the Company has the burden of proof that the costs are both known and measurable and prudent. The Company claimed that it seeks to recover projected incentive compensation and that it is reasonably certain that the Company's incentive compensation program, will be achieved. Without certainty, or a definitive level of known and measurable costs related to incentive compensation, it is unreasonable for the Company to expect all recovery of costs that it will assume to be incurred. The Company stated that it cannot yet know the final outcome of the performance goals. If the Company includes all projected costs related to incentive compensation and subsequently does not pay out all of the projected incentive compensation, due to certain performance metrics and goals not being met by employees, it would be difficult to recover these costs back to ratepayers. The Company is assuming an all or nothing approach and is not appropriate as it is an unrealistic approach to recovering costs.

c. Employee Benefits

Q. WHAT HAS THE COMPANY STATED IN REGARD TO YOUR EMPLOYEE BENEFITS – HEADCOUNT ADJUSTMENT?

A. Ms. Hazenstab stated that she did not agree with my adjustment to normalize the Company's medical and dental costs over FY 2021-2023. (Statement No. 2-R at 14). Ms. Ressler in Statement No. 3-R stated that she did not agree with my adjustment because the Company relied upon the analysis provided by its insurance broker based upon a national survey but then tailored specifically to UGI's covered population. (Statement No. 3-R at 38). Ms. Ressler stated that Pennsylvania healthcare costs tend to be overall in line with the national average, while healthcare costs in bordering states are higher than the costs in Pennsylvania. Ms. Ressler stated that the broker indicated that UGI's population is slightly older than average, which was factored into the specific increase that the broker recommended for UGI. (Statement No. 3-R at 38). UGI's reliance on the analysis provided by its broker is a normal business practice and that my adjustment provides no basis whatsoever to call into question the analysis of the broker. (Statement No. 3-R at 38).

Q. WHAT DID MS. RESSLER STATE REGARDING YOUR RECOMMENDATION ON THE COMPANY EXPLORING MORE AFFORDABLE HEALTHCARE OPTIONS?

A. Ms. Ressler stated that the Commission should not rely upon my recommendation with respect to exploring more affordable healthcare options. Ms. Ressler stated that I did not provide any study, report, review evaluation or analysis of whether the Company has switched to a hybrid workplace or reduced employee costs by switching to a hybrid workplace. (Statement No. 3-R at 39). Ms. Ressler also stated that I indicated, in response to UGI-Gas-OCA-I-17, that I did not, nor did I prepare any study, report, review evaluation or analysis of the savings UGI Gas could gain by switching to a hybrid workplace, including savings related to my claim that the Company could refinance health care option. (Statement No. 3-R at 39).

Q. WHAT IS YOUR RESPONSE?

A. In response to I&E RE-28, the Company stated that it included a 7% increase and a 2% increase for its FTY and FPFTY projected claims for Dental plans, and an 8% increase for both the FTY and FPFTY periods for Medical plans. However, the Company has not provided any further information but for the arguments addressed by Ms. Ressler in her Statement No. 3-R and the reliance of its broker taken from a national survey. The Company has not provided any additional information such as insurance invoice premiums that reflect the increased costs. In addition, knowing that medical and dental costs are increasing, the Company should look into options that may reduce cost to the Company and to the employee. In response to I&E RE-28, the Company stated that it did not prepare claims for medical and dental costs as the information is not available. Even though I did not provide any study, report, or review calculations or analysis of potential savings, the Company should not be short-sighted in not preparing its own analysis of the benefits of a hybrid workplace and whether or not costs can be achieved.

d. Environmental Remediation

Q. WHAT DID MS. RESSLER STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S ENVIRONMENTAL REMEDIATION EXPENSE ADJUSTMENT?

A. Ms. Ressler did not agree with my 5-year amortization period to recover the environmental remediation costs for Environmental Adjustment #1 and #3. She stated that the current 5-year amortization periods for the under-recoveries of costs in the period prior to FY 2019 and during FY 2029 are the results of agreements in prior cases and have no bearing on the correct amortization to apply in this proceeding for the FY 2020 and FY 2021 under-recoveries. She stated the Company continues to incur expenditures for environmental remediation and for each year since 2019 has spent more than it recovered in rates, thereby adding to its regulatory asset under-recovery each year. (Statement No. 3-R at 11-12). Ms. Ressler stated that further delay in recovery results in additional mismatch between the periods in which the costs incurred and the period of recovery. Given the Company's frequent rate case filings, it is most appropriate to allow the Company to recover these costs currently so that they are not a lingering issue for future rate proceedings. Ms. Ressler stated that the Company's environmental costs are fully reconcilable, and it is illogical to attempt to minimize the amount of annul recovery

Q. WHAT IS YOUR RESPONSE?

A. With respect to the Company's Environmental Remediation adjustment #1, the use of a five-year average reduces the recovery by $43,733, which is not a major difference. In response to Confidential response I&E -RE-44 **(BEGIN CONFIDENTIAL)** the Company stated that the use of a three-year period was to eliminate high and low spend and approximating an average year of spend. **(END CONFIDENTIAL)**. Given that the use of a five year average results in a minimal difference, it is appropriate and consistent to use this five year time period with other environmental adjustments. I do not believe there is precedent to use a three-year average for this adjustment, and so I disagree with the Company's determination that the use of a three-year average is reasonable in this case. With respect to the Company's one-year recovery of Environmental Adjustment #3, the Company stated in Confidential response to I&E – RE- 44 **(BEGIN CONFIDENTIAL)** it believes this is a reasonable period between rate cases **(END CONFIDENTIAL)**. I do not believe there is a precedent to use a one-year recovery for this adjustment, and as I stated previously, it is consistent with other environmental adjustments. If the Company's environmental expenditures become increasingly high in future years, adding to the under-recovery each year, then the timing and amortization period year should be revisited at that time.

e. Outside Contractors

Q. WHAT HAS MS. RESSLER STATED WITH REGARD TO YOUR ADJUSTMENT TO THE COMPANY'S OUTSIDE CONTRACTOR EXPENSES?

A. Ms. Ressler did not agree with my adjustments related to Outside Contractors for Distribution Expense ($2,114,000), Customer Accounts ($9,000) and A&G ($22,000). (Statement No. 3-R at 13). Ms. Ressler stated that the Company renegotiated its contracts with outside contractors approximately every three to four years. The 2020 and 2021 costs for outside contractors were based upon pricing from the 2018 negotiation, while the FPFTY costs will be based on the pricing from the 2022 negotiation. She stated that it is not appropriate to use prior periods for outside contractor costs for the FPFTY, as these costs are based on entirely different and outdated contracts and the new contract costs are known and measurable. Based upon these updated contracts, the Company has proposed an adjustment to increase its claim for outside contractor labor by $2,692,000 as discussed in the rebuttal testimony of Mr. Timothy Angstadt. (Statement No. 3-R at 14). Ms. Ressler stated that my normalization period that I used resulted in the lowest amount of allowed expense of the three normalization periods available. Ms. Ressler stated that I selected different normalization periods without explanation and my method appears to be wholly arbitrary. (Statement No. 3-R at 14-15).

Q. WHAT IS YOUR RESPONSE?

A. In reviewing the response to OCA-Set III-33, the Company's Outside Contractor expenses related to A&G expenses were lower in 2019 and increased in the years 2020 through 2023; Customer Accounts expenses were higher in 2019 and 2020, lower in 2021 and higher in 2022 and 2023; Distribution expenses were higher in 2019 and declined in 2020, 2021, and increasing in 2022 and 2023. These are the balances and expense levels. I used the most recent three-years to compute my adjustments to these Outside Contractor expenses, and I did not select years in which the Company's costs were greater than other years. That would be cherry-picking to the benefit of the Company. Outside Contractors expenses do vary from year to year because they are volatile and are out of the control of the Company. As I stated in my direct testimony, there is no discernable trend that shows a gradual increase or decrease in these costs. They fluctuate from year to year. In its Rebuttal testimony the Company claimed that based upon updated contracts, the Company has proposed an adjustment to increase its claim for outside contractor labor by $2,692,000.

Q. WHAT DID MR. ANGSTADT STATE REGARDING INCREASED OPERATING COSTS?

A. Mr. Angstadt stated that the Company received the results from three RFP's for pipeline construction and maintenance, restoration, and traffic control services contained within a Master Pipeline Construction Agreement, Master Restoration Services Agreement and the Master Pipeline Support Services Agreement. The results of these agreements reflect a significant impact of inflation on all parts of the Company's operations, both on contractor costs that affect pipeline replacement and restoration activities and on activities that drive operations and maintenance expenses. (Statement No. 9-R at 1-2). Mr. Angstadt stated that the increase in prices is driven by inflationary pressures impacting all elements of the Company's gas operations. (Statement No. 9-R at 3). Pipeline construction labor market is constrained, and the region is experiencing extremely low unemployment rates. Contractors must pay higher labor rates and those rates are passed on to UGI Gas. Inflationary impacts to materials, equipment and supplies are also reflected in the bids received by the Company in response to its RFP. (Statement No. 9-R at 4). Mr. Angstadt stated that the Company has quantified the impact of the increased contractor costs on its expense claim (UGI Gas Exhibit TJA-1R and in response to OCA-III-33). Mr. Angstadt stated that the Company's outside contractor expenses in this case for the FPFTY was $21.723 million and with the impact of incorporating the increased contractor costs received by the Company in the 2022 RFP increased outside contractor expenses by $2.692 million for a total of $24.416 million. (Statement No. 9-R at 4).

Q. WHAT IS YOUR RESPONSE?

A. In reviewing Mr. Angstadt Exhibit TJA-2R, I am accepting the Company's outside contractor expenses and the increase in its pipeline, restoration, and traffic control. I am not accepting the Company's Plant Contractor Labor Other in the increased amount of $594,000. These costs were increased based on the CPI percentage which I believe are not known and measurable. The use of a CPI increase is not supportive of costs incurred by the Company but rather an overall blanket-type adjustments that are applied to all goods and services that may not be directly related to costs incurred by the Company. It is simply a prediction of cost adjustments. While inflation adjustments are used to develop economic data it should not be used for ratemaking purposes. Goods and services fluctuate, the costs increase and decrease over time. My adjustment is shown on my Schedule SR-DM-12, SR-DM-13, and SR-DM-17.

f. Employee Activity Costs

Q. WHAT HAS MS. RESSLER STATED WITH REGARD TO YOUR ADJUSTMENTS TO EMPLOYEE ACTIVITIES EXPENSES?

A. Ms. Ressler stated that she did not agree with my adjustment of $588,226. (Statement No. 3-R at 40). Ms. Ressler stated that this proposed costs is for a reasonable level of normal employee activities to allow the opportunity for employees to develop relationships with one another and to recognize service tenure. A reasonable calendar of activities designed to reward and incentivize employees is important to employee retention. (Statement No. 3-R at 41). Ms. Ressler stated that the Company has experienced an increase in voluntary turnover in a tight labor market, and given this situation, it would not be prudent for the Company to eliminate programs that contribute to the retention of qualified personnel who are responsible for the provision of safe, reliable natural gas service. Ms. Ressler stated that the Company believed that its investment in a reasonable level of employee activities is worthwhile to create an environment conducive to employee satisfaction. (Statement No. 3-R at 41).

Q. WHAT IS YOUR RESPONSE?

A. Ratepayers should not be responsible for employee morale or productivity, but rather the Company should be wholly responsible for providing a safe, healthy and productive workplace. I do not see a nexus between Company celebrations, activities, picnics and other in-hour celebratory gatherings with safe, adequate and reliable service to customers. While I commend the Company recognizing employees for staying at the Company, and building a comradery among employees, I do not see a nexus between these costs and the ability for the Company to provide safe and reliable natural gas service to customers. Ratepayers do not benefit from employees to attend picnics, service awards, holiday gathering or other socially related events. The Company should not ask for costs and expenses—not related to their duties and responsibilities—to be recovered from ratepayers over and above the employee's compensation. Ratepayers should not be burdened to pay for costs for improving or enhancing employee morale. Employees should not be incentivized to perform their duties and responsibility that they were initially hired to perform in the first place. My recommendation is the same as my recommendation in my direct testimony which disallows the Company's Employee Activities costs of $588,276 and is shown on my Schedule SR-DM-17.

g. OSHA Compliance

Q. WHAT HAS COMPANY WITNESS MS. RESSLER STATED REGARDING YOUR ADJUSTMENT TO THE COMPANY'S CLAIM ASSOCIATED WITH OSHA / ETS COMPLIANCE?

A. Ms. Ressler stated that the already-incurred costs related to OSHA / ETS compliance of $52,934 should be recovered from ratepayers. These costs were incurred by the Company to obtain legal advice related to complying with the mandate (in advance of the Supreme Court's decision) and to subscribe to a vaccine tracking software. (Statement No. 3-R at 42). Ms. Ressler stated that these costs were reasonably and prudently incurred at the time they were incurred and not whether the costs are deemed moot based on the facts and circumstances that after the costs were incurred. (Statement No. 3-R at 42).

Q. WHAT IS YOUR RESPONSE?

A. Utilities should be afforded the opportunity to recover costs that are used and useful, and benefit ratepayers when rates are set for service. These OSHA/ETS costs of $52,934 that the Company incurred was at the time related to complying with the mandate. Given that the mandate has been overturned and no similar mandate will pass into law, these costs will not benefit ratepayers in the FPFTY, regardless of whether the costs incurred were prudent at that time. The Company runs the risks in this situation of having costs not being recovered in rates. The Company indicated that the mandate was initially to be effective in January 2022, and the Company needed to be prepared to implement the requirements (OCA-Set III-25). This costs were simply imprudently incurred.

h. Advertising

Q. WHAT HAS MS. RESSLER STATED IN RESPONSE TO YOUR ADJUSTMENT REGARDING ADVERTISING EXPENSE?

A. Ms. Ressler did not agree with my adjustments related to Other Advertising Programs of $885,178 and for Conservation Advertising of $659,827. (Statement No. 3-R at 44). Ms. Ressler stated that Other Advertising Programs consist primarily of costs for sponsorships, building meetings/trade shows, and branded promotional items. Attending these events allows the Company to raise awareness of natural gas as an option, and to develop relationships and discuss the benefits of natural gas with other attendees. These sponsorships are key to attracting additional customers and these additional customers reduce the overall revenue requirement that is borne by each individual customer. (Statement No. 3-R at 45). Ms. Ressler stated that she did not agree with my normalization of Conservation Advertising over a three-year period. (Statement No. 3-R at 45). Ms. Ressler stated that I was incorrect in stating that the Company did not record any costs to this account in FY 2019, but rather the Company recorded $603,642 on Conservation of Energy advertising in FY 2019. (Statement No. 3-R at 46). Ms. Ressler stated that I appeared to be cherry-picking normalization periods to minimize the Company's allowed claim and that I selected different periods for different adjustments. In the case of conservation advertising the period selected included the year that was most impacted by the COVID-19 pandemic (2020) but excluded the prior year when conservation advertising costs were higher (2019). (Statement No. 3-R at 47).

Q. WHAT IS YOUR RESPONSE TO CONSERVATION ADVERTISING?

A. With respect to my error that the Company did not record any Conservation Advertising in FY 2019, I am accepting Ms. Ressler's statement. I reviewed Attachment III-A-25 and realized that the Company did record costs in FY 2019 related to Conservation Advertising. Given that 2020 was an off year due to the COVID-19 pandemic, and not to be cherry-picking to minimize the Company's allowed claim, I substituted FY 2020 for FY 2019 for costs related to Conservation Advertising, resulting in a normalized three-year average reduction of $119,528 instead of my prior recommendation of $193,114, a difference of $73,586. I am still continuing to recommend a normalized three-year average because the Company has not provided any further information for the 70% increase from FY 2021 to FY 2022. Ms. Ressler stated that the Company is resuming normal activities in print and digital channel advertising related to conservation – related efforts but has not provided any updated information to support this. My adjustment is shown on my Schedule SR-DM-16.

Q. WHAT IS YOUR RESPONSE WITH RESPECT TO OTHER ADVERTISING PROGRAMS?

A. I am still recommending removal of the Company's Other Advertising Programs of $885,178. As I stated in my direct testimony, these types of costs appear to support or bolster the Company's image and reputation. The Company has not provided any further information with respect to whether any ratepayers of the Company had attended or were aware that these types of events were being held. The Company did not provide any information as to whether any attendees actually signed up for natural gas service and ultimately became customers of the Company. My recommendation is still the same and is shown on my Schedule SR-DM-16.

i. Sponsorship

Q. WHAT HAS MS. RESSLER STATED WITH RESPECT TO YOUR ADJUSTMENT RELATED TO SPONSORSHIPS EXPENSES?

A. Ms. Ressler stated that she did not agree with my adjustment related to sponsorship costs of $424,000. Ms. Ressler stated that these costs are essential to maintaining ties in the communities where the Company provides service. These opportunities ensure that the

Company's potential customer base remains aware the Company and services it provides, and they serve as an attraction for potential customers and potential employees. Ms. Ressler stated that my adjustment of $424,000 is duplicative of my adjustment related to Other Advertising Programs as within this category of advertising as required for this standard filing requirement. (Statement No. 3-R at 48). Ms. Ressler stated that, in Attachment III-A-28.1, $389,774 is included within FERC account 930.2, and therefore, a portion of my adjustment should be rejected solely because it is duplicative of my earlier adjustment to Other Advertising Programs. (Statement No. 3-R at 48).

Q. WHAT IS YOUR RESPONSE?

A. I am still of the opinion that Sponsorship expenses do not provide benefits to ratepayers. The Company should not be using ratepayer monies to maintain ties in the communities. While a utility company may choose to be a good corporate citizen in the communities that they serve, the role of the utility company that ratepayers should fund is to provide safe and adequate utility service. I do not see a nexus between these Sponsorship costs and gas utility service. With respect to the Company's issue on my duplicative adjustment related to Other Advertising Programs and the fact that these costs are included in the Company's Miscellaneous General Expenses shown on Attachment III-A-28.1, the Company should provide a schedule that shows the duplicative adjustment between Sponsorship expenses and Other Advertising Expenses, and I will make the necessary adjustments to eliminate any duplicative adjustment.

j. Membership Dues

Q. WHAT HAS MS. RESSLER STATED REGARDING YOUR ADJUSTMENT TO MEMBERSHIP DUES?

A. Ms. Ressler did not agree with my adjustment to remove $540,192 related to Membership Dues Expense (Statement No. 3-R at 49). Ms. Ressler stated that these Membership Dues are related to economic development corporations (PA Chamber of Business & Industry, PA Economy League) which allows the Company to grow its customer base, primarily by attracting new industrial and commercial customers. These organizations work primarily with large commercial companies who are making site selections, and the Company's active involvement in these organizations allows it to proactively work with these targets, promoting the benefits of natural gas for their energy needs and encouraging them to select sites that are located in close proximity to existing gas mains. Without these membership and active involvement in these organizations, the Company would experience less commercial growth, resulting in higher costs passed along to ratepayers, including its residential customers. (Statement No. 3-R at 51). Ms. Ressler stated that these organizations have a variety of purposes, including the promotion of safe operating practices, advocating for renewable natural gas resources, growing the use of natural gas and the sharing of information among utilities. These Membership Dues allow the Company to benefit from resources provided by these various organizations, receiving information about safety and reliability, as well as growth within natural gas and renewables, all of which benefit ratepayers. (Statement No. 3-R at 51). Ms. Ressler stated that my proposed adjustment is not sound as the Company's original filing at Attachment SDR-RR-30 shows total membership costs at $1,115,404 but noted that $32,858 is related to lobbying costs and excluded from the Company's claims; Ms. Ressler stated that my adjustment should have been $430,130. (Statement No. 3-R at 55).

Q. WHAT IS YOUR RESPONSE?

A. I believe many of these costs do not comport to costs associated with the provision of providing natural gas service to customers. Chambers of Commerce, consortiums, Economic Development, Advocating before members of the General Assembly, market data and labor data information, and community development appears to be costs associated with non-utility issues. Ratepayers do not have a say as to which entities these costs are paid to**,** nor do they provide any customer utility service benefit. In 66 Pa. C.S. Section 1316.1, no public utility may charge to its customers as a permissible operating expense for ratemaking purposes, costs related to fraternal, social or sports clubs or organization. While I do not see any sports or social type fees as noted in Attachment SDR-RR-30, I do note that most of these costs are related to Chambers of Commerce, business alliances, economic development and advocating before members of the General Assembly. I believe these types of costs should not be recovered from ratepayers.

Therefore, I am continuing to recommend disallowance of these costs in rates. I noted that I erred in my adjustment to Membership Dues. In response to an Interrogatory Request from the Company in OCA Set I-13, I adjusted my disallowance from $540,912 to $462,988. Ms. Ressler stated that I did not adjust my disallowance by removing $32,858 of costs related to lobbying costs. I believe I did. My recommendation is shown below and, on my Schedule SR-DM-17.

Total Membership Dues – SDR-RR-30	$1,115,404
American Gas (net of Lobbying)	$ 597,416
Northeast Gas Association	$ 55,000
Total Disallowance	$ 462,988

k. Pension Expense

Q. WHAT HAS MS. RESSLER STATED WITH REGARD TO YOUR ADJUSTMENT TO PENSION BENEFITS EXPENSE?

A. Ms. Ressler did not agree with my normalization of the pension expense over a three-year period. She stated that if the Company's actual cash contributions are normalized it actually increases the Company's claim from $5.501 million to $5.765 million, an increase of $0.264 million. (Statement No. 3-R at 15-16). Ms. Ressler stated that my normalization adjustment should be rejected because of my misunderstanding of the basis for the Company's claim to recover pension costs which is a cash contribution to the pension fund; is inconsistent with the established ratemaking practice in Pennsylvania which allows public utilities to claim certain expense based upon the cash contribution to their pension fund and; is arbitrary and inconsistent with proposed normalization periods regarding other categories of expenses. (Statement No. 3-R at 16). Ms. Ressler stated that my adjustment would result in a claim which is based neither on GAAP expense nor cash contributions and is not connected to the Company's cost for providing pension benefits. (Statement No. 3-R at 16-17). Ms. Ressler stated that my adjustment is based upon historical figures and not based upon up to date information or the full amount of the current cash contribution amount. (Statement No. 3-R at 18). Ms. Ressler stated that the Company's contributed to its pension plan based upon the cash contributions as calculated by its third-party actuarial firm, and if the Company accepted my adjustment, its actual cash contribution would not change. (Statement No. 3-R at 18).

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S ARGUMENT REGARDING YOUR NORMALIZATION ADJUSTMENT TO PENSION EXPENSES?

A. I believe it is appropriate to average out contributions made in prior years to contributions made during current years. In response to OCA-VII-3, the Company's Pension Expense has fluctuated from a high of $6.417 million of expense in 2018 to a low of ($2.887 million) of income in 2022 and for the FPFTY period. The cash contributions attributable to UGI Gas has varied from $10.618 million in 2018, to $8.849 million in 2019, to $9.937 million in 2020, to $10.038 million in 2021 and to $9.168 million in 2022. The Company has not provided information as to the reason why its pension expense went from $2.434 million of expense in 2021 to pension income in 2022 of $2.887 million, a difference or a swing of $5.321 million ($2.434 million plus ($2.887) million. While I understand that the Company based its cash contribution by relying on its actuarial firms recommendation, and the fact that the Company made its adjustment based upon GAAP and established ratemaking practices in Pennsylvania, historical costs that were incurred should be taken into consideration, as solely relying on current actually-determined cash contributions to the pension fund can result in costs that may be too high *or* too low for the new regulatory period when new rates are set. Costs changes over time, but not always proportionately.

l. Corporate Allocation of ESG Costs and Company Membership Costs

Q. WHAT HAS MS. RESSLER STATED REGARDING YOUR ADJUSTMENT TO ITS ENVIRONMENTAL, SOCIAL AND GOVERNANCE COSTS AND COMPANY MEMBERSHIP COSTS?

A. Ms. Ressler did not agree with my adjustment related to the Company's Environmental, Social and Governance (ESG) costs. She stated that these costs are important to the investor community which secures the future success of the Company and enables the continued provision of safe and reliable service to customers by funding capital investment. (Statement No. 3-R at 20). Ms. Ressler stated that ESG costs is a hot topic and investors are interested in a Company ESG strategy and often request this information prior to investing in a Company's stock. Ms. Ressler stated that the New York Stock Exchange has developed an ESG Resource Center website for its members and investors and the United States Securities and Exchange Commission (SEC) proposed enhanced and standardized climate-related disclosures from its registrants. (Statement No. 3-R at 20). Ms. Ressler stated that a portion of the ESG costs will be used to prepare for and/or comply with this SEC proposal, and failure to align with shareholders' ESG expectations can lead to an increased cost of capital. (Statement No. 3-R at 21). Ms. Ressler stated that ratepayers benefit from ESG activities which are focused on environmental stability, social policies that promote diversity and inclusion, and governance of the Company to ensure that it has a clear purpose and strategic direction. Ratepayers benefit because strong policies in this area allow the Company to access capital markets to obtain the capital that is necessary to funds its replacement and betterment program. (Statement No. 3-R at 21). ESG activities focus on the collection of needed environmental, social and governance data in an efficient manner, which limits the cost of this activity and lowers the overall expense passed along to ratepayers. (Statement No. 3-R at 21).

Q. WHAT IS YOUR RESPONSE?

A. I am continuing to recommend removal of these costs from rates. I believe these costs are geared or pitched towards the Company's financial success and growth to satisfy the investor community. The Company is free to fund these costs through shareholder monies but should not expect ratepayers to pay for these costs that relate to supporting social movements, societal impacts and financial factors in the investor world to maintain a level of financial returns or growth. As I testified in my direct testimony, I am of the opinion that ESG costs are not related to the provision of safe and reliable utility services to ratepayers, but rather, are costs related to and are akin to national and societal issues, sponsorships and civic related activities. I am not convinced that these ESG costs actually benefits or lowers costs to ratepayers.

m. Rate Case Expense

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENT TO RATE CASE EXPENSES?

A. Ms. Hazenstab did not agree with my adjustment to amortize these costs over a two-year period. (Statement No. 2-R at 9). Ms. Hazenstab stated that the frequency of the Company's past base rate cases is not a predictor of the frequency of future base rate cases. The time frame between the Company's most recent base rate proceeding at Docket No. R-2019-3015162 and the current one was subject to a one-year settlement stay-out clause that prohibited the Company from making a base rate filing earlier than January 2, 2022, effectively added one-year to the period when the Company could not make a filing. Removing that 1-year period would reduce the normalization period and my recommendation is not supported by any particular rationale and should be rejected outright. (Statement No. 2-R at 9-10).

Q. WHAT IS YOUR RESPONSE?

A. I am continuing recommending normalizing rate case expenses based upon actual prior rate case expense filings. The fact that the Company was subjected to a one-year stay out does not change my position, as my recommendation is based upon prior rate case filings and the frequency of historic rate case filings, and not based upon this instant proceeding, or whether the Company was subjected to a one-year settlement stay out. It is my understanding that the Commission looks to the historical filing frequency to determine the proper normalization period, which in this case, calculates to a 24-month (2 year) period. Prior rate case filing typically acts as a guide to rate case frequency. My recommendations are the same as that in my direct testimony and is shown on my Schedule SR-DM-17.

Q. WHAT OTHER ARGUMENTS DID MS. HAZENSTAB STATE AS TO THE REASONS FOR A ONE-YEAR RATE CASE NORMALIZATION PERIOD?

A. Ms. Hazenstab stated that the Company is expected to file another base rate case in one year based upon an assessment of future capital requirements, continued information system improvements through the UNITE project, and the cost of other improvements as detailed in the Company's second LTIIP filing. Ms. Hazenstab stated that all of the Company's operating expenses are subject to inflation and the revenue requirements for plant additions that are not Distribution System Improvement Charge (DSIC) eligible will cause further pressure to file a rate case within one year after the rates in this case become effective. (Statement No. 2-R at 10).

Q. WHAT IS YOUR RESPONSE?

A. My arguments for a two-year normalization period are the same. The Company's argument, that it files base rate cases annually, does not comport to what it has historically filed in the past. In response to OCA-III-16, the Company, on average has filed base rate case proceeding every two years. The Company filed two rate cases in 2016 and 2017 and two rate cases in 2019 and 2020. There was a five year gap between 2011 and the next rate case 2016. There was a two year gap between the 2020 filing and this instant filing. As I reiterated previously, the one-year stay out does not change the pattern of rate case frequency. The Commission is not bound by the Company's request to recover rate case expenses over a one-year period.

n. Depreciation

Q. WHAT DID MS. RESSLER STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S DEPRECIATION EXPENSE?

A. Given that the Company did not agree with my adjustments to the Company's plant in service balance, the Company has disagreed with my adjustments to my recommended Depreciation Expense, which are derivatives of my adjustments to the Company's plant in service (Statement No. 3-R at 56).

Q. WHAT IS YOUR RESPONSE?

A. Since I am accepting the Company's plant in service balance, I am accepting the Company's Depreciation Expense in the amount of $124,782,000. The Company has updated its Depreciation claim by $18,000 as a result of reducing its plant in service balance (Statement No. 3-R at 56).

o. State and Local Taxes

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S STATE AND LOCAL TAX EXPENSE?

A. Ms. Hazenstab stated that she agreed with my adjustment related to the Pennsylvania State and Local tax expense in the amount of **(BEGIN CONFIDENTIAL)** $77,000 **(END CONFIDENTIAL)**.

Q. WHAT IS YOUR RESPONSE?

A. Given that Ms. Hazenstab has accepted my adjustment related to the Company's Pennsylvania State and Local Taxes, I have no further adjustments. This is shown on my Schedule SR-DM-19.

p. Interest Synchronization

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENT TO THE COMPANY'S INTEREST SYNCHRONIZATION?

A. Ms. Hazenstab stated that she did not agree with my income tax expense which is based upon OCA's recommendation to rate base and capital structure. Ms. Hazenstab stated that this adjustment is related to OCA witness Mr. David Garrett's adjustments to the Company's capital structure and cost of equity, as well as my recommended rate base balance. (Statement No. 2-R at 19-20).

Q. WHAT IS YOUR RESPONSE?

A. I relied on Mr. Garrett's recommendation related to the Company's capital structure and overall cost of debt. Mr. Garrett recommended a weighted cost of debt of 1.99% which calculates to an overall interest synchronization balance of $63,188,732. With respect to my recommended rate base balance, I have addressed these concerns under my Rate Base section II A. This is shown on my Schedule SR-DM-20.

C. Act-40 Requirements (Act 40 of 2016)

Q. WHAT DID MS. HAZENSTAB STATE REGARDING YOUR ADJUSTMENTS TO THE COMPANY'S CONSOLIDATED TAX ADJUSTMENT (CTA) AND ACT 40 OF 2016?

A. Ms. Hazenstab stated that I argued that the Company has not demonstrated the remaining 50% of the CTA had been used related to general corporate purposes. (Statement No. 2-R at 21). Ms. Hazenstab stated that, while it is not practical to trace a hypothetical amount to specific projects, 50% of the Act 40 amount will be used to for general operating expenses of the Company. Ms. Hazenstab stated that, in the Company's Exhibit A - FPFTY Schedule B-4, the Company's total budgeted O&M expense is $625,766,000 and that these expenses will be used to benefit ratepayers including $2.177 million in meter reading expenses, $28.149 million for the maintenance of mains, and $35.342 million for various customer service expenses and, therefore, the Company spent over 50% of the hypothetical CTA on general expenses that are specifically for the purpose of providing utility service to ratepayers. (Statement No. 3-R at 22). Ms. Hazenstab stated that, based upon the advice of counsel, the utilities need only to show that their capital expenditures, and expenditures on other general corporate purposes, exceed the fifty percent of the differential in tax expense resulting from Act 40. (Statement No. 2-R at 23). Ms. Hazenstab stated that the testimony presented by the Company in its direct testimony in this case is similar to the testimony that was accepted by the presiding Administrative Law Judges and the Commission in the Company's 2018 Electric Division rate case. (Statement No. 2-R at 24). Ms. Hazenstab stated that my CTA adjustment to rate base would result in a tax normalization violation raising the risk of an adverse IRS ruling on the issues. Ms. Hazenstab stated that my adoption of my CTA adjustment has the potential of jeopardizing the loss of $628.595 million of ADIT to the detriment of the Company's customers and adversely impact the cash position of the Company, as those taxes may become due immediately, which the risk clearly overwhelms the minor benefit for customers that would result from my adjustment for tax benefits that are not the result of the Company's activities but rather the activities of the Company's non-regulated affiliates. (Statement No. 2-R at 25).

Q. WHAT IS YOUR RESPONSE?

A. The Company should not benefit from the use of the compliance with Act 40 without any specific use related to general corporate purposes. While Ms. Hazenstab stated that 50% of the CTA is related to “rate base eligible” infrastructure and has demonstrated that the Company has utilized these dollars for such, the Company simple omits how the other 50% of the differential is to be used for general corporate purposes. Ratepayers are already supporting the Company’s infrastructure and reliability investments through rates; more information is needed to show that the additional revenues now being provided by ratepayers is actually being used and not simply going to shareholders. The Company should provide evidence of actual applications of its differential related to general corporate purposes in a manner that reduces ratepayer obligations. In response to OCA-III-20, I asked the Company to show how the 50% of the CTA is used to support general corporate purposes. The Company responded by stating that the $760 million operating expense budget is more than the CTA adjustment related to general corporate purposes of $1,825 million. With respect to any IRS violations, the Commission has the broad authoritative oversight to set rates based upon ratemaking principles and does not have to rely on whether any IRS violations exists. There will always be a difference of how the Company records costs on its books and records for corporate purposes, and how the Company records costs on its books and records for ratemaking purposes based upon Commission rulings.

Q **DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

A. Yes, it does.

SUMMARY SCHEDULE

Measure of Value and Revenue Increase

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Rate Base	$ 3,176,596,000	$ (1,282,824)	$ 3,175,313,176	
2	Rate of Return	8.100%		6.240%	
3	Operating Income Requirement	$ 257,304,276	$ (59,164,734)	$ 198,139,542	
4	Present Rate Income	$ 196,026,000		$ 215,452,122	
5	Income Deficiency	$ 61,278,276	$ (78,590,856)	$ (17,312,580)	
6	Gross Revenue Conversion Factor (2)	1.429864		1.429864	
7	Revenue Requirement Increase	$ 87,619,601	$ (112,374,236)	$ (24,754,635)	

(1) Company Schedule A-1
(2) Company Schedule D-35

	Company Proposed	OCA Recommended	References
Gross Revenue Factor	1.000000	1.000000	
Uncollectible Expense	(0.016470)	(0.016470)	DM-14
	0.983530	0.983530	
State Income Taxes - 9.99%	0.098255	0.098255	
Factor After State Taxes	0.885275	0.885275	
Federal Income Taxes - 21.00%	0.185908	0.185908	
Net Operating Income Tax Factor	0.699368	0.699368	
Gross Revenue Conversion Factor	1.429863	1.429863	
difference due to rounding			

RATE OF RETURN

		Ratio	Cost Rate	Weighted Avg.
(1)	Company Proposed			
1	Long-Term Debt	44.910%	4.300%	1.93%
2	Short-Term Debt	0.000%	0.000%	0.000%
3	Common Equity	55.090%	11.200%	6.17%
4	**Total**	100.000%		8.101%
	OCA Recommended - (2)			
5	Long-Term Debt	50.000%	3.980%	1.990%
6	Short-Term Debt	0.000%	0.000%	0.000%
7	Common Equity	50.000%	8.500%	4.250%
8	**Total**	100.000%		6.240%

(1) Company Schedule B-7
(2) D. Garrett recommendation

MEASURE OF VALUE
Rate Base Valuation

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Gas Utility Plant In Service	$ 5,041,354,000	$ -	$ 5,041,354,000	OCA-Set X-2 I&E RB-4
2	Accumulated Depreciation	$ (1,318,079,000)	$ -	$ (1,318,079,000)	
3	Net Gas Utility Plant In Service	$ 3,723,275,000	$ -	$ 3,723,275,000	
4	Working Capital Allowance	$ 61,697,000	$ (5,824)	$ 61,691,176	DM-7
5	Gas Inventory	$ 25,094,000	$ -	$ 25,094,000	
6	Customer Deposits	$ (21,434,000)	$ -	$ (21,434,000)	
7	Materials & Supplies	$ 16,559,000	$ -	$ 16,559,000	
8	Sub-Total	$ 20,219,000	$ -	$ 20,219,000	
9	Accumulated Deferred Income Taxes	$ (628,595,000)	$ -	$ (628,595,000)	
	Consolidated Income Taxes	$ -	$ (1,277,000)	$ (1,277,000)	OCA-III-20
10	Total Measure of Value - Rate Base	$ 3,176,596,000	$ (1,282,824)	$ 3,175,313,176	

(1) Company Schedule C-1

OPERATING INCOME STATEMENT

		(1)		Company Proposed				Present Rates	
		Budget Year		Proforma		Proforma		OCA	
		9/30/2023	Adjustments	Present Rates	Adjustments	Proposed Rates	Adjustments	Recommended	References
	Operating Revenues								
1	Customer & Distribution Revenue	$ 602,316,000	$ 22,767,000	$ 625,083,000	$ -	$ 625,083,000		$ 625,083,000	
2	Gas Supply & Cost Adj. Revenue	$ 384,431,000	$ 42,923,000	$ 427,354,000	$ -	$ 427,354,000		$ 427,354,000	
3	Other Revenue	$ 8,936,000	$ 348,000	$ 9,284,000	$ -	$ 9,284,000	$ -	$ 9,284,000	Sch D-2
4	Rate Increase	$ -	$ -	$ -	$ 87,619,000	$ 87,619,000		$ -	
5	Total Operating Revenues	$ 995,683,000	$ 66,038,000	$ 1,061,721,000	$ 82,742,000	$ 1,149,340,000		$ 1,061,721,000	OCA-VII-5
	Operating Expenses								
6	Gas Production	$ 14,000	$ 983,000	$ 997,000	$ -	$ 997,000	$ (43,400)	$ 953,600	DM-9
7	Gas Supply Production	$ 358,286,000	$ 38,877,000	$ 397,163,000	$ -	$ 397,163,000	$ -	$ 397,163,000	DM-10
8	Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
9	Distribution	$ 84,369,000	$ 3,853,000	$ 90,127,000	$ -	$ 90,127,000	$ (2,572,390)	$ 87,554,610	DM-12
10	Customer Accounts	$ 40,541,000	$ 1,829,000	$ 42,046,000	$ -	$ 42,046,000	$ -	$ 42,046,000	DM-13
11	Uncollectible Accounts	$ 14,419,000	$ 2,176,000	$ 16,595,000	$ 1,362,761	$ 18,038,000	$ (1,850,406)	$ 16,187,594	DM-14
12	Customer Information & Service	$ 10,368,000	$ 3,496,000	$ 13,864,000	$ -	$ 13,864,000	$ -	$ 13,864,000	DM-15
13	Sales	$ 1,725,000	$ 13,000	$ 1,738,000	$ -	$ 1,738,000	$ (1,004,706)	$ 733,294	DM-16
14	Administrative & General	$ 116,044,000	$ 12,313,000	$ 126,527,000	$ -	$ 126,527,000	$ (20,816,642)	$ 105,710,358	DM-17
	S&W adjustment - other overall - open position:	$ -	$ -	$ -		$ -	$ (779,368)	$ (779,368)	DM-11
15	Sub-Total	$ 625,766,000	$ 63,540,000	$ 689,057,000	$ 1,362,761	$ 690,500,000	$ (27,066,912)	$ 663,433,088	
16	Depreciation & Amortization	$ 128,358,000	$ (2,821,000)	$ 124,782,000	$ -	$ 124,782,000	$ (750)	$ 124,781,250	DM-17
17	Taxes Other Than Income Taxes	$ 13,283,000	$ 298,000	$ 13,524,000	$ -	$ 13,524,000	$ (552,449)	$ 12,971,551	DM-18
18	Total Operating Expenses	$ 767,407,000	$ 61,017,000	$ 827,363,000	$ 1,362,761	$ 828,806,000		$ 801,185,889	
19	Net Operating Income Before Income Taxes	$ 228,276,000	$ 5,021,000	$ 234,358,000	$ 81,379,239	$ 320,534,000		$ 260,535,111	
									Co. Sch D-33
20	Income Taxes - Present Rates	$ 38,332,000	$ -	$ 38,332,000	$ 24,898,000	$ 38,332,000		$ -	DM-19
21	Income Taxes - Revenue Increase					$ 24,898,000			
	Total Income Taxes	$ 38,332,000	$ -	$ 38,332,000	$ 24,898,000	$ 63,230,000		$ 45,082,989	
22	Net Income	$ 189,944,000		$ 196,026,000	$ 56,481,239	$ 257,304,000		$ 215,452,122	
	check							$ (17,312,580)	
	Rate Base	$ 3,176,596,000		$ 3,176,596,000		$ 3,176,596,000		$ 3,175,313,176	
	Rate of Return	5.979%		6.171%		8.100%		6.240%	
	Check	$ 189,944,000		$ 196,026,000		$ 257,304,276		$ 198,139,542	

(1) Company Schedule D-1 D-2 and D-5

GAS UTILITY PLANT IN SERVICE

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Intangible Plant	$ 774,000		$ 774,000	
2	Natural Gas Production & Gathering	$ 1,197,000		$ 1,197,000	
3	Natural Gas Storage & Processing Plant	$ 382,000		$ 382,000	
4	Transmission Plant	$ 50,141,000		$ 50,141,000	
5	Distribution Plant	$ 4,449,130,000		$ 4,449,130,000	I&E RB-4D
6	General Plant - 391 - UNITE - 6.70% (2)	$ 539,730,000		$ 539,730,000	OCA-III-8/23/28
7	Other Plant	$ -		$ -	Confidential
8	Total Gas Plant In Service	$ 5,041,354,000	$ -	$ 5,041,354,000	OCA-III-2
					OCA-III-19
					OCA-X-2

(1) Company Schedule C-2
(2) Includes $60.028 million for UNITE

ACCUMULATED DEPRECIATION

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Intangible Plant	$ -			
2	Natural Gas Production & Gathering	$ 1,153,000	$ -	$ 1,153,000	
3	Natural Gas Storage & Processing Plant	$ 33,000	$ -	$ 33,000	
4	Transmission Plant	$ 29,633,000	$ -	$ 29,633,000	
5	Distribution Plant - 2.06%	$ 1,131,094,000		$ 1,131,094,000	
6	General Plant - 5.71%	$ 156,166,000		$ 156,166,000	
7	Total Accumulated Depreciation	$ 1,318,079,000	$ -	$ 1,318,079,000	

(1) Company Schedule C-3

WORKING CAPITAL ALLOWANCE

		(1)					
			Company Proposed				OCA
		TY Expenses	Factor	Lead/Lag Days	Totals	Adjustments	Recommended
1	Revenue Lag Days				61.18		61.18
	Expense Lag Days						
2	Payroll	$ 82,237,000	12.00	$ 986,844,000			$ 936,060,000
3	Purchased Gas Costs	$ 397,163,000	39.85	$ 15,826,945,550		$ -	$ 15,826,945,550
4	All Other Expenses (3)	$ 193,062,000	27.08	$ 5,228,118,960			$ 5,098,218,581
5	Total	$ 672,462,000		$ 22,041,908,510			$ 21,861,224,131
6	O&M Expense Lag				32.78		32.78
7	Net Lead/Lag Days				28.413		28.41
8	Operating Expenses Per Day				$ 1,842,362		$ 1,817,625
9	Working Capital for O&M Expenses				$ 52,347,021		$ 51,644,176
10	Interest Payments				$ (5,054,000)		
11	Tax Payments				$ 4,402,000		
12	Prepaid Expenses				$ 10,047,000		$ 10,047,000
13	Total Working Capital Requirements (2)				$ 61,742,021	$ (50,845)	$ 61,691,176

(1) Company Schedule C-4
(2) differences due to rounding
(3) OCA-III-21

use company schedule and confirm balance

ACCUMULATED DEFERRED INCOME TAXES

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Gas Utility Plant	$ (633,775,000)	$ -	$ (633,775,000)	
	Rebuttal Adjustment	$ (85,000)		$ (85,000)	
2	CIAC	$ 27,405,000	$ -	$ 27,405,000	
3	Federal ADIT	$ (606,455,000)	$ -	$ (606,455,000)	OCA Set III-30 OCA Set III-31
4	State Repairs Regulatory Liability	$ (34,960,000)	$ -	$ (34,960,000)	
	Sub-Total	$ (641,415,000)	$ -	$ (641,415,000)	
5	Pro-Rate Adjustment - EDIT (2)	$ 12,820,000	$ -	$ 12,820,000	OCA-III-30 Confidential
6	Balance At TY Period 9/30/2023	$ (628,595,000)	$ -	$ (628,595,000)	

(1) Company Schedule C-6
(2) Components of the EDIT are Confidential not the balance

GAS PRODUCTION

		(1) Company Proposed	Adjustments	DCA Recommended	References
1	Beginning Balance	$ 14,000		$ 14,000	
	Environmental Expense Adj. #1				
2	2019 Expenditures	$ 4,811,000			OCA-Set VII-2
3	2020 Expenditures	$ 4,243,000			
4	2021 Expenditures	$ 6,460,000			
5	Three-Year Average	$ 5,171,333	$ (43,333)	$ 5,128,000	5 yr Avg. Confidential
6	Budgeted Expense	$ 4,188,000		$ 4,188,000	I&E RE-44
7	Proforma Adjustment	$ 983,333		$ 939,600	
8	Balance at Proforma Period	$ 997,333	$ (43,733)	$ 953,600	

(1) Company Schedule D-2, D-3, D-8

GAS SUPPLY PRODUCTION

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 358,286,000	$ -	$ 358,286,000	
2	Residential Gas Costs	$ 25,674,000	$ -	$ 25,674,000	
3	Commercial/Industrial Gas Costs	$ 13,203,000	$ -	$ 13,203,000	
4	Total Revenue for Cost of Gas	$ 38,877,000	$ -	$ 38,877,000	Sch. D-6
5	Balance at Proforma Period	$ 397,163,000	$ -	$ 397,163,000	

(1) Company Schedule D-2, D-3

SALARIES AND WAGES Worksheet	(1) Budget Year	Table 7 Benchmark Adjustments	Sch. D-7 Merit Increases	SDR-RR-27 Incentive Compensation	Additional Employees	Total Proforma	Adjustments	OCA Recommended
Distribution Operations	$ 27,859,000	$ 1,148,000	$ 416,000	$ 51,000	$ 643,000	$ 30,117,000	$ (51,000)	$ 30,066,000
				$ 38,000	$ 585,000	$ 623,000	$ (38,000)	$ 585,000
Distribution Maintenance	$ 13,023,000		$ 195,000			$ 13,218,000	$ -	$ 13,218,000
Customer Accounts	$ 14,479,000		$ 216,000			$ 14,695,000	$ -	$ 14,695,000
Customer Service & Information	$ 1,042,000		$ 16,000			$ 1,058,000	$ -	$ 1,058,000
Sales	$ 899,000		$ 13,000			$ 912,000	$ -	$ 912,000
Administration & General - Operations (2)	$ 20,661,000		$ 309,000			$ 20,970,000	$ (2,312,000)	$ 16,055,000
Administration & General - Operations (2)							$ (2,603,000)	
Administration & General - Maintenance	$ 1,395,000		$ 21,000			$ 1,416,000	$ -	$ 1,416,000
Total Budgeted Salaries & Wages	$ 79,358,000	$ 1,148,000	$ 1,186,000	$ 89,000	$ 1,228,000	$ 83,009,000	$ (5,004,000)	$ 78,005,000
Total Benchmark Adjustments - check		$ 2,465,000						

Add'l Employees	64	OCA-Set III-7
Approved and identified	47	
Open Positions	(17)	
avg. salary	$ 45,845	I&E RE-5A
overall	$ (779,368)	To DM-4
	$ (5,694,368)	to DM-19

(1) Company Schedule D-7
Company Schedule D-3

(2) See I&E RE-17 - management incentive plan of $2,603,000
See I&E RE-17 UGI Incentive of $2,312,000

DISTRIBUTION EXPENSES

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 84,369,000		$ 83,775,000	
	Outside Contractor Expenses		$ (594,000)		OCA-III-33
	Salaries and Wages				
2	Distribution Operations	$ 416,000	$ -	$ 416,000	
3	Distribution Maintenance	$ 195,000	$ -	$ 195,000	Sch. D-7
4	Total Salaries and Wages	$ 611,000	$ -	$ 611,000	
	Adjustment 1				
5	Compensation Benchmark	$ 1,148,000	$ -	$ 1,148,000	Set III-11/13
6	Incremental Incentive Bonus	$ 51,000	$ (51,000)	$ -	
		$ 1,199,000		$ 1,148,000	
7	Employee Benefits - 10%	$ 119,900	$ (5,100)	$ 114,800	
8	Total Compensation Benefits	$ 1,318,900	$ (56,100)	$ 1,262,800	Sch D-9
	Adjustment 2				
9	Cybersecurity - 5 positions ($101K)	$ 585,000	$ -	$ 585,000	OCA Set III-12
10	Employee Benefits - $9,702x5 >10%	$ 48,510	$ -	$ 48,510	OCA Set III-17
11	Incentive Bonus 7.5% of $505,000	$ 43,875	$ (37,875)	$ -	
12	Total Cybersecurity	$ 677,385	$ (43,875)	$ 633,510	Sch. D-9
13	Unbudgeted Annual Capacity Lease Chrg.	$ 565,000	$ -	$ 565,000	Sch. D-15
	Succession Planning - Field Operations				
14	20 Additional Positions	$ 643,000	$ -	$ 643,000	
15	Employee Benefits cap at 10%	$ 124,000	$ (59,700)	$ 64,300	
16	Proforma Balance	$ 767,000	$ (59,700)	$ 707,300	Sch. D-17 Set III-17
17	Balance at Proforma Period	$ 88,308,285	$ (753,675)	$ 87,554,610	
	Increase over budgeted costs	$ 3,939,285			

(1) Company Schedule D-2, D-3

CUSTOMER ACCOUNTS EXPENSE

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 40,541,000	$ -	$ 40,541,000	OCA-III-33
2	Salaries and Wages	$ 216,000	$ -	$ 216,000	Sch. D-6
3	Emergency Relief Program (ERP)	$ 922,000	$ -	$ 922,000	OCA-III-24
4	Amortization period - Years	10		10	
5	Proforma Annual Recovery	$ 92,200	$ -	$ 92,200	Sch D-12
6	Unrecovered Interest on Cust. Deposits	$ 648,000	$ -	$ 648,000	Sch. D-15
					I&E RE-15
7	Universal Service Expenses	$ 548,000	$ -	$ 548,000	Sch. D-16
					I&E RE-50
8	Balance at Proforma Period	$ 42,045,200	$ -	$ 42,045,200	I&E RE-49
	Increase over budgeted costs	$ 1,504,200			

(1) Company Schedule D-2, D-3

UNCOLLECTIBLE ACCOUNTS EXPENSE

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 14,419,000		$ 14,419,000	Sch. D-11
2	Three-Year Average Tariff Revenues	$ 840,499,000			
3	Three-Year Average Uncollectibles	$ 13,841,000			
4	3-Yr Uncollectible Ratio	1.6470%		1.6470%	
5	2022 Present Rate Revenues - (2)	$ 1,058,040,000		$ 1,058,040,000	
6	Adjusted Uncollectibles	$ 17,426,000		$ 17,426,000	
7	Budgeted Uncollectibles	$ 15,400,000		$ 15,400,000	OCA-Set VII-1
8	Additional Uncollectibles	$ 2,026,000		$ 2,026,000	
9	Regulatory Asset Balance	$ 1,503,000	$ -	$ 1,503,000	OCA-III-24
10	10 Amortization Period	$ 150,300	$ -	$ 150,300	
11	Total Uncollectible Adjustment	$ 2,176,300		$ 2,176,300	OCA-VII-1
12	Balance at Proforma Period	$ 16,595,300		$ 16,595,300	
	Increase over budgeted costs	$ 2,176,300			
	Adjustment to Uncollectible Accounts			$ (407,706)	

(1) Company Schedule D-2, D-3

(2) Total Present Revenues less Misc.
Revenues and Rent From Gas Properties

CUSTOMER INFORMATION & SERVICES

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 10,368,000	$ -	$ 10,368,000	OCA-III-6
2	Salaries and Wages	$ 16,000	$ -	$ 16,000	
3	Energy Efficiency & Conservation	$ 3,480,000		$ 3,480,000	I&E RE-51 OCA-VII-6
4	Balance at Proforma Period	$ 13,864,000		$ 13,864,000	
	Increase over budgeted costs	$ 3,496,000			

Check for Advertising, I&E RE-31
Section 53.53 III-A-25

(1) Company Schedule D-2, D-3 and D-7
Company Schedule D-19

SALES EXPENSE

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance	$ 1,725,000	$ (1,004,706)	$ 720,294	I&E-RE-31
	Other Advertising Expense - Acct 913		$ (885,178)	$ -	III-A-25
	Normalized Conservation Advertising		$ (119,528)	$ -	
2	Salary and Wages	$ 13,000	$ -	$ 13,000	Sch. D-7
3	Balance at Proforma Period	$ 1,738,000	$ (1,004,706)	$ 733,294	
	Increase over Budgeted costs	$ 13,000			

Advertising Demonstrating and Selling I&E RE-30
Miscellaneous Sales
Section 53.53 Attachment III-25

(1) Company Schedule D-2, D-3
I&E RE-30

ADMINISTRATIVE & GENERAL EXPENSES

		(1) Company Proposed	Adjustments	OCA Recommended	References
					OCA-VII-7
1	Beginning Balance	$ 116,044,000	$ (13,755,342)	$ 102,288,658	OCA-VII-8
	Company Membership Adjustment - Acct. 930		$ (462,988)		SDR-RR-30
	Employee Activity - Acct . 926		$ (588,226)		I&E RE-24
	Sponsorships - Acct. 930		$ (424,000)		I&E RE-22
	Corporate Allocation-Incentive/Stock Awards - Acct. 923 (2)		$ (6,213,000)		I&E RE-17 OCA-X-1
	ESC Costs - Acct. 923		$ (115,094)		OCA-X-1
	Management Incentive Plan - $2,603,000 - Acct. 920 (2)		$ (2,603,000)		OCA- VII-13 - Set XI-1 (Conf)
	UGI Incentive - Acct. 920 (2)		$ (2,312,000)		I&E RE-17
	Outside Contractors Expenses		$ -		OCA-III-33
	Employee Benefits - Acct. 926		$ (1,037,034)		I&E RE 28
2	A&G Operations Salaries	$ 309,000	$ -	$ 309,000	
3	A&G Maintenance Salaries	$ 21,000	$ -	$ 21,000	
4	Total Salaries and Wages	$ 330,000	$ -	$ 330,000	Sch. D-7
	Adjustment #3				
5	Environmental Adjustments (2020-2021)	$ 10,703,000	$ -	$ 10,703,000	
6	Balance Recovered in Prior Years	$ 8,376,000	$ -	$ 8,736,000	I&E RE-44
7	Unrecovered Expenditures (2)	$ 2,327,000	$ (1,861,600)	$ 465,400	Sch. D-8
	Rate Case Expenses - 1 yr. Amorization				
8	Total Expenses	$ 1,055,000	$ (527,500)	$ 527,500	OCA-III-16
9	Rate Cases Included in Budget	$ 1,000,000		$ 1,000,000	
10	Additional Expense	$ 55,000	$ (527,500)	$ (472,500)	Sch. D-10
	OSHA - ETS Compliance Costs				
11	Ongoing Costs for Tracking /Testing	$ -	$ -	$ -	OCA-III-25
12	One-Time Cost - Comm/Legal	$ 53,000	$ (53,000)	$ -	OCA-III-25
13	Proforma Adjustment	$ 53,000	$ (53,000)	$ -	Sch. D-13
	Benefits Adjustment (Acct. 926)				OCA-III-22
14	Per Budget	$ (2,887,000)	$ 6,222,667	$ 3,335,667	OCA-VII-3
15	Cash Contributions	$ 11,364,000	$ 705,333	$ 12,069,333	
16	Estimated Cash Contributions	$ 9,168,000	$ 440,000	$ 9,608,000	
17	Capitalized Portion -40%	$ (3,667,200)	$ (176,000)	$ (3,843,200)	
		$ 5,500,800	$ 264,000	$ 5,764,800	
18	Proforma Adjustment	$ 8,387,800	$ (5,958,667)	$ 2,429,133	Sch. D-14
	Other Adjustments - I&D Acct. 925 (3)				
19	Three-Year average I&D	$ 1,353,333	$ -	$ 1,353,333	
20	Budgeted I&D	$ 2,023,000	$ -	$ 2,023,000	
21	Proforma Adjustment	$ (669,667)	$ -	$ 669,667	Sch. D-15
22	Balance at Proforma Period	$ 126,527,133	$ (20,816,775)	$ 105,710,358	
	Increase over Budgeted costs	$ 10,483,133			
					OCA-VII-7

Check for Dues Subscriptions Employee Benefits, Activities, Membership Dues, Rental Expenses
PBOB and Other benefits, Investor Relations
Insurance Premiums - Property Insurance Acct. 925
Advertisement Section 53.53 III-A-25

(1) Company Schedule D-2, D3
(2) Red designated Confidential Information
(3) Includes Property Insurance

DEPRECIATION & AMORTIZATION EXPENSE

		Depreciation Rate Composite	(1) Company Proposed	Adjustments	OCA Recommended	References
1	Beginning Balance		$ 128,358,000	$ -	$ 128,358,000	
2	Intangible Plant	0.000%	$ -	$ -	$ -	
3	Natural Gas Production & Gathering	0.120%	$ 1,398	$ -	$ 1,398	
4	Natural Gas Storage & Processing	0.000%	$ -	$ -	$ -	
5	Transmission Plant	1.310%	$ 658,505	$ -	$ 658,505	
6	Distribution Plant	2.060%	$ 91,484,000		$ 91,484,000	I&E RB-4
7	General Plant	5.710%	$ 13,660,951		$ 13,660,951	I&E RB-4
						Confidential
	Other Plant:					
8	Common Plant - Allocated to Gas	3.630%	$ 1,311,428	$ -	$ 1,311,428	
9	Information Services Allocated to Gas	6.570%	$ 17,806,088	$ -	$ 17,806,088	OCA-III-8
		1.880%	$ 2,705,627	$ -	$ 2,705,627	
10	Empire Yard Building		$ (35,345)	$ -	$ (35,345)	
			$ 127,592,652	$ -	$ 127,592,652	OCA-III-26
11	Charged to Clearing Accounts		$ (8,371,000)	$ -	$ (8,371,000)	
12	Net Salvage Amortization		$ 6,083,750	$ -	$ 6,083,000	
	Rebuttal Adjustment		$ (523,402)		$ (523,402)	
	Company Proposed		$ 124,782,000	$ (750)	$ 124,781,250	OCA-III-27
13	Adjustment		$ (3,576,000)	$ (750)	$ (3,576,750)	

(1) Company Schedule D-21
Weidmayer Schedule II-3 to II-5

UGI Utilities, Inc. - Gas Division
Test Year Ending 9/30/2023

PA Public Utility Commission
Docket No. R-2021-3030218

Schedule SR-DM-19

TAXES OTHER THAN INCOME TAXES

		(1) Company Proposed	Adjustments	OCA Recommended	References
1	**Beginning Balance**	$ 13,360,000	$ -	$ 13,360,000	
					Confidential
2	PURTA Taxes	$ 822,000	$ -	$ 822,000	OCA-III-18
3	Capital Stock	$ -			OCA-III-18
4	PA & Local Taxes	$ 1,791,000		$ 1,791,000	Confidential
	<u>Payroll Taxes:</u>				
5	Total Payroll	$ 79,358,000	$ (5,694,368)	$ 73,663,632	
6	FICA Rate	7.59%		7.5900%	
7	**Budget Amount**	$ 6,023,272	$ (432,203)	$ 5,591,070	I&E RE-3
8	Additional Payroll	$ 2,879,000	$ (96,000)	$ 2,783,000	
9	Additional FICA Taxes	$ 218,516	$ (7,286)	$ 211,230	
10	**FUTA Expense - 0.14239%**	$ 113,000	$ -	$ 113,000	
11	Additional FUTA Expense	$ 4,099	$ (137)	$ 3,963	
12	**SUTA Expense - 0.6212%**	$ 493,000	$ -	$ 493,000	
13	Additional SUTA Expense	$ 17,884	$ (596)	$ 17,288	
14	**Total Additional Payroll Taxes**	$ 240,500	$ (8,019)	$ 232,480	
15	PUC Assessment	$ 4,042,000	$ -	$ 4,042,000	OCA-III-18
16	**Balance at Proforma Period**	$ 13,524,000	$ (552,449)	$ 12,971,551	

(1) Company Schedule D-31, D-32

	FEDERAL & STATE INCOME TAXES	Present Rates			
		Company Proposed	Adjustments	OCA Recommended	References
1	Revenues	$ 1,149,340,000	$ (87,619,000)	$ 1,061,721,000	
2	Operating Expenses	$ (828,806,000)	$ 27,620,111	$ (801,185,889)	
3	Operating Income Before Taxes	$ 320,534,000	$ (59,998,889)	$ 260,535,111	
4	Interest Synchronization	$ (56,861,068)	$ (6,327,664)	$ (63,188,732)	
5	Base Taxable Income	$ 263,672,932	$ (66,326,553)	$ 197,346,379	
6	State Tax Depreciation over/under book	$ (133,816,000)	$ (4,495,000)	$ (138,311,000)	Co. Sch. D-34
7	State Taxable Income	$ 129,856,932	$ (70,821,553)	$ 59,035,379	
8	State Tax Rate - 9.99%	$ 12,972,707	$ (7,075,073)	$ 5,897,634	
9	Federal Tax Depreciation over/under book	$ (101,401,000)	$ (4,493,000)	$ (105,894,000)	
10	Federal Taxable Income	$ 149,299,224	$ (63,744,480)	$ 85,554,745	
11	Federal Tax Rate - 21.00%	$ 31,352,837	$ (13,386,341)	$ 17,966,496	
12	Total Tax before DIT	$ 44,325,545	$ (20,461,414)	$ 23,864,131	
	Deferred Federal Income Taxes				
13	Federal Tax over/under book	$ 98,131,000	$ 4,495,000	$ 102,626,000	
14	Federal Tax Rate - 18.03915% - blended	$ 17,702,000	$ 810,858	$ 18,512,858	OCA Set III-29
	Deferred State Income Taxes				
15	Repairs	$ 3,110,000	$ -	$ 3,110,000	
16	CIAC	$ (80,000)	$ -	$ (80,000)	
17	State Deferred Income Taxes	$ 3,030,000	$ -	$ 3,030,000	
18	Net Income Tax Expense	$ 65,057,545	$ (19,650,556)	$ 45,406,989	
19	ITC	$ (324,000)	$ -	$ (324,000)	
20	Combined Income Tax Expense	$ 64,733,545	$ (19,650,556)	$ 45,082,989	
	Federal Tax	$ 48,730,837		$ 36,155,354	
	State Tax	$ 16,002,707		$ 8,927,634	
	Check Total	$ 64,733,545	$ (19,650,556)	$ 45,082,989	

Company Schedule D-33

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Dante Mugrace, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 1SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2022
*329519

Signature: Dante Mugrace
Dante Mugrace

Consultant Address: PCMG and Associates
90 Moonlight Court
Toms River, NJ 08753

OCA St. 2SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	
v.	Docket No. R-2021-3030218
UGI Utilities, Inc. – Gas Division	

SURREBUTTAL TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 27, 2022

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is David J. Garrett. My business address is 101 Park Avenue, Suite 1125, Oklahoma Company, Oklahoma 73102.

Q. By whom are you employed and in what capacity?

A. I am the managing member of Resolve Utility Consulting, LLC. I am an independent consultant specializing in public utility regulation.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I filed direct testimony in OCA Statement 2 on April 20, 2022, on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"). I also filed rebuttal testimony in OCA Statement 2R on May 17, 2022. A summary of my qualifications is included in my direct testimony.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony primarily responds to the rebuttal testimony of UGI Utilities, Inc. – Gas Division's ("UGI" or the "Company") witness Paul Moul. I also address a few issues raised in the rebuttal testimony of UGI witness Christopher Brown.

Q. Did any of the Company's rebuttal testimony you reviewed cause you to change your positions and recommendations as stated in your direct testimony?

A. No. To the extent I did not specifically address a statement made in the Company's rebuttal testimony filed in this case, it should not constitute my agreement with such testimony.

Q. In his rebuttal testimony, did Mr. Moul raise any new, significant issues related to your cost of equity and rate of return testimony and analysis?

A. No. In Mr. Moul's rebuttal testimony, it is clear that he disagrees with my opinions regarding UGI's cost of capital and my return on equity ("ROE") recommendation. However, I do not believe he raised any new, significant arguments or issues in addition to those provided in his direct testimony. Thus, in my surrebuttal testimony, I will not repeat all of the arguments and points raised in my direct testimony; rather, I will reiterate a few important points in my response to Mr. Moul's rebuttal testimony.

Q. Please describe the organization of your surrebuttal testimony.

A. In my surrebuttal, I respond to several pertinent issues discussed in Mr. Moul's rebuttal testimony, including (1) capital structure; (2) the Discounted Cash Flow ("DCF") Model; (3) Mr. Moul's ROE comparisons; (4) the results of the Capital Asset Pricing Model ("CAPM"); (5) the leverage adjustment; and (6) the management performance premium. Finally, I respond to issues raised in the rebuttal testimony of Mr. Brown.

I. CAPITAL STRUCTURE

Q. Please summarize Mr. Moul's surrebuttal testimony regarding capital structure.

A. Mr. Moul disagrees with my recommendation to adjust the Company's ratemaking capital structure. Mr. Moul claims that I did not demonstrate that UGI's proposed ratemaking capital structure is unreasonable.[1] Mr. Moul also points to capital structures authorized for other companies in other rate cases to support his assertion that the Commission should accept the Company's proposed capital structure.

[1] Direct Testimony of Paul R. Moul, p. 10, lines 10-11.

Q. Did you demonstrate in your direct testimony that UGI's proposed debt ratio is unreasonably low?

A. Yes. I provide three different analyses that each indicated the Company's proposed debt ratio is too low for ratemaking purposes. In summary, I analyzed the capital structures of the proxy group, UGI's parent company, and other competitive industries. Particularly, the debt ratios of the proxy group should be considered when assessing a reasonable debt ratio for UGI. This is because the metrics obtained from the proxy group to estimate cost of equity (and ultimately the authorized ROE) are necessarily interrelated with the capital structures of the proxy group. I demonstrated this fact mathematically in my Hamada model, which shows how various debt ratios impact the cost of equity.[2] The average debt ratio of Mr. Moul's (and my) proxy group is 53%, which is considerably higher than the Company's proposed debt ratio of 45%. If the average debt ratio of the proxy group were only 45%, the cost of equity indicated from that group would be lower. Thus, by accepting other metrics of the proxy group while ignoring their debt ratios, Mr. Moul's overall cost of capital recommendation is unreasonably high.

Q. Can you quantify the impact on the cost of equity resulting from the difference in a 53% debt ratio and a 45% debt ratio?

A. Yes. This issue was discussed in my direct testimony as it relates to the Hamada model. Using the Hamada model presented in my testimony, the Company's indicated CAPM cost of equity at a 45% debt ratio is 7.2%. The Company's indicated CAPM cost of equity at a 53% debt ratio, however, is 7.9%. Thus, setting aside the various assumptions about the risk-free rate, beta, and the equity risk premium, the difference in these debt ratios indicates

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[2] Exhibit DJG-17.

a difference in the cost of equity estimate of about 0.7% (or 70 basis points). Also, as shown in my Hamada model, the Company's indicated cost of equity at a 50% debt ratio (which is my recommended ratemaking debt ratio) is 7.62%, which is notably lower than my recommended authorized ROE for the Company.

Q. What is the impact to the revenue requirement related to your proposed capital structure adjustment?

A. If the Commission were to authorize my proposed capital structure adjustment, it would reduce the revenue requirement by $10.3 million.

Q. Are the authorized capital structures for other utilities relevant to this proceeding?

A. Relatively speaking, they are not. When determining a fair ratemaking debt ratio for UGI, the Commission should focus on a debt ratio that might be observed for UGI if it existed in a purely competitive environment. We can look to the debt ratios of the proxy group as an indication of what UGI's debt ratio might look like in a comparative environment. The average debt ratio of the proxy group is 53%. Similarly, the average debt ratio of UGI's parent company is also 53%. Based on this analysis, it would be reasonable to conclude that, for ratemaking purposes, UGI's debt ratio should be 53%. In the interest of gradualism, I propose a ratemaking debt ratio for UGI of 50%.

Q. Mr. Moul claims that your proposed capital structure is inconsistent with Commission policy. Do you have a response?

A. Yes. I am not aware of a specific Commission "policy" that would require the Commission to simply accept a regulated utility's proposed capital structure. It is incumbent on the Commission to ensure that all of the Company's costs passed to ratepayers are prudent, which means they might require an adjustment. This is especially true with one of the Company's most significant costs: capital costs. As demonstrated in my testimony, the

Company's proposed capital structure results in capital costs that are not at their lowest reasonable level.

Q. Mr. Moul claims that your proposed capital structure "merely lowers the Company's revenue requirement."[3] Do you have a response?

A. Yes. From a mathematical standpoint, adopting my proposed ratemaking capital structure for UGI would result in a lower revenue requirement, all else held constant (which is quantified above). However, I take exception with Mr. Moul's testimony here because it implies that the purpose of my capital structure adjustment is to lower the Company's revenue requirement, which is not the case. From this standpoint, however, I could argue that many of the decisions made by Mr. Moul with regard to his cost of equity models "merely increase" the Company's revenue requirement, such as the various premiums he adds to his models and the unreasonable assumptions he makes – all which have increasing effects on the cost of capital estimate and revenue requirement. I stand by the belief that my proposed adjustments to the Company's authorized ROE and capital structure are fair and reasonable, and they are not designed to achieve a particular revenue requirement outcome.

Q. Mr. Moul claims that your examination of the capital structure of UGI's parent company is "without merit." Do you have a response?

A. Yes. The Commission should ensure that UGI's capital costs are reasonable, of which capital structure is a key component. What is considered "reasonable" in terms of capital structure analysis would be to ensure that UGI is operating with a capital structure that might be observed for the Company if it operated in a purely competitive (unregulated)

[3] Rebuttal Testimony of Paul R. Moul, p. 10, lines 11-12.

environment, since unregulated companies have a natural financial incentive to minimize capital costs (i.e., operate with sufficient amounts of debt). I can think of no better proxy for assessing a competitive debt ratio for UGI than the reported debt ratio of its unregulated parent company. In my opinion, the Commission should strongly consider the fact that UGI Corp's debt ratio is 53%, which is notably higher than the Company's proposed ratemaking debt ratio of only 45%.

II. <u>DCF MODEL</u>

Q. Please summarize Mr. Moul's surrebuttal testimony regarding the growth rate input to the DCF Model.

A. Mr. Moul disagrees with my use of projected nominal GDP as a limiting factor for long-term growth projections of the proxy utility group. Mr. Moul relies instead on the growth rates published by various analysts.

Q. Please summarize the problems you have with the growth rates Mr. Moul used in his DCF Model.

A. The problems I have with Mr. Moul's growth rate inputs could be summarized into several key points: (1) analysts' growth rates cover short-term time periods; (2) it is not reasonable to assume that any company can outpace the growth rate of the aggregate economy in which it operates over the long run; and (3) Mr. Moul's growth rates result in a DCF Model that must be overstated given it exceeds a reasonable estimate for the market cost of equity. I will address each of these points below.

Q. Are the analyst growth rates used by Mr. Moul in his DCF Model long-term growth rates?

A. No. Growth rates published by various analysts typically cover a period of 3 – 10 years. However, the growth rate input in the constant growth DCF Model (or the terminal growth rate in a multi-stage DCF Model) contemplates a *long-term* period of time (technically, infinity). Regardless of the quantitative accuracy of the published growth rates Mr. Moul relies upon, the Commission should understand that it is Mr. Moul, not the commercial analysts, who is suggesting to the Commission that the proxy companies will experience these annual rates of growth year after year for many years into the future.

Q. Is it reasonable to assume that a company's earnings or dividends will grow at an annual rate greater than that of the projected annual growth rate of the aggregate economy in which it operates?

A. No, I do not believe so. This is a fundamental concept in finance, but it also make sense intuitively. The growth rate of our economy is most widely measured by U.S. GDP. As discussed in my direct testimony, a reasonable projection of annual GDP growth going forward is about 3.8% (over the long-run). We could think of GDP as an "average" of sorts, which means there are relatively high-growth companies (that have not yet reached their mature stage of the lifecycle) that are bringing the average up, and likewise, there are relatively low-growth companies that are bringing the average down. Some companies would even have negative growth rates (i.e., decreasing earnings and/or dividends). The growth rates of all the companies in the U.S. market are constantly changing over time, but GDP growth is relatively consistent. Mathematically, if a company were to consistently outpace GDP growth year after year, then it would eventually have earnings that exceeded U.S. GDP, regardless of its starting point. An appropriate metaphor might be two runners in an infinite race. If Runner A runs at a faster pace than Runner B, Runner A will eventually surpass Runner B no matter the head-start distance Runner B was given. It is simply not reasonable to assume that the earnings of any one company, especially a low-growth utility, would ever surpass U.S. GDP.

Q. Do the results of Mr. Moul's DCF analysis appear unreasonable in light of the strong likelihood that they exceed a reasonable estimate for the current market cost of equity?

A. Yes. Regardless of the differing opinions regarding technical aspects of long-term growth indicators in the DCF Model, we should nonetheless check the results for reasonableness. Since the growth rate input in the DCF Model is the primary driver of the end results (given the fact that stock prices and dividends much less subjective), then an unreasonably high DCF result based on market indicators could be primarily attributable to an unreasonably high growth rate input. Mr. Moul's DCF Model produced a result of 11.21%.[4] Since the average beta of the proxy group is less than 1.0, then the market cost of equity (which is based on a beta equal to 1.0) acts as a "ceiling" on UGI's cost of equity. The market cost of equity is estimated by adding the risk-free rate (as estimated by the current yield on 30-year U.S. Treasury bonds) to the equity risk premium ("ERP"). Although the ERP will be discussed in more detail below in relation to the CAPM, it is instructive here as part of our cost of equity "ceiling" estimate. The current risk-free rate is about 2.4%.[5] A reasonable estimate for the ERP is about 5.5%.[6] Thus a reasonable estimate for the market cost of equity is about 8%. Any cost of equity estimate for UGI that is more than 300 basis points above this estimate for the "ceiling" is clearly unreasonable.

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[4] Direct Testimony of Paul R. Moul, p. 37.

[5] *See* Exhibit DJG-7.

[6] *See* Exhibit DJG-10.

Q. Mr. Moul suggests that gas utilities can outpace GDP growth over the long-run due to asset replacement programs. Do you have a response?

A. Yes. I will reiterate some of the lengthy discussion in my direct testimony on this issue. First, from a quantitative standpoint, utilities can achieve earnings growth that exceed U.S. GDP growth. However, as explained in my direct testimony, this relationship suffers from two important problems that the Commission should consider from the standpoint of considering a fair and accurate application of the DCF Model. First, using a utility's quantitative earnings growth in a particular period as the long-term growth rate assumption in the DCF Model suffers from a feedback loop that is not present in the CAPM. In this case (as in most cases), the short-term growth rate assumptions reported by analysts such as Value Line are notably higher than long-term GDP growth. If those short-term rates are used for the sustainable growth rate input in the DCF Model to asses cost of equity, it will inevitably result in an inflated cost of equity estimate, which will presumably lead to inflated earnings growth, and the cycle continues.

Second, I do not believe a utility's ability to increase earnings by simply increasing its rate base is indicative of real, qualitative growth that should be directly considered as a quantitative input in a fair application of the DCF Model. The reason for my opinion on this issue is that competitive (non-regulated) companies cannot simply increase the amount of capital assets on its balance sheet and automatically see earnings growth results. Investing in large capital projects is risky, and unless it results in increased market share over the long-run, such investments will not necessarily generate earnings growth. Unlike many competitive firms, UGI does not have the ability to launch new product lines, franchise, or expand to new and developing markets in order to increase market share and achieve real, qualitative growth. Rather, any quantitative earnings growth UGI will realize will be as a result of rate increases authorized by the Commission, which may be partially driven by merely retiring and replacing assets to serve its existing customer base. In the competitive environment, this dynamic does not represent how companies actually grow. Utilities in general, including UGI, are effectively non-growth companies, but that does not prevent their shareholders from seeking quantitative earnings growth through increased rate bases and proposals to the regulator for authorized ROEs (and capital structures) that result in awarded returns that clearly exceed market-based capital costs.

Q. Do you have any remarks regarding the use of the Quarterly Approximation DCF Model you used in this case?

A. Yes. Although Mr. Moul and I clearly disagree on several issues related to the DCF Model, he does not criticize my use of the Quarterly Approximation DCF Model. In fact, Mr. Moul also considers a variation of the DCF model which assumes the quarterly compounding of dividends, among other variations.[7] In my opinion, it is reasonable to use any of the DCF Model variations that consider different timings of dividend growth, whether it is annually, semi-annually, or quarterly. In addition, these variations do not have a signification impact on the results. For example, in Mr. Moul's exhibits, he presents a semi-annual, annual, and quarterly variation of the DCF, which results in dividend yields of 3.50%, 3.53%, and 3.49%, respectively.[8] This highlights the fact that variations in DCF results are primarily driven by growth rate assumptions (and potential premiums added to the model such as the leverage adjustment), rather than the type of DCF Model being used.

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[7] *See* UGI Gas Exhibit B, Sch. 7.

[8] *Id*.

III. Comparison to Pennsylvania Allowed ROEs

Q. Please comment on Mr. Moul's comparison to utility returns recently authorized by the Commission.

A. Mr. Moul cites to a variety of ROEs allowed by the Public Utility Commission since 2018.[9] They include ROEs for small and large gas utilities, a small electric utility, and a large water utility. Several were determined based on market information before the impact of the COVID-19 pandemic. The PUC allowed PECO Gas a 10.24% ROE based upon a time frame which included the COVID-19 pandemic shut-down and re-opening. What Mr. Moul does not show is that any of the allowed rates of returns incorporated his particular approach to estimating a cost of equity, such as his leverage adjustment to the DCF and CAPM.

Q. Mr. Moul also references an ROE identified by the Commission for use in electric utility Distribution System Improvement Charges (DSICs). Should the Commission use that DSIC ROE as a limit in this proceeding?

A. No, I disagree with Mr. Moul's suggestion. I have been advised that the DSIC allows UGI to impose a surcharge to recover certain eligible investments in natural gas infrastructure replacements between base rate cases. As such, the DSIC amounts to an automatic rate recovery mechanism for UGI that, in turn, lowers its risk.

Commission regulations allow UGI to implement a DSIC surcharge to further public policy which favors replacement of certain natural gas infrastructure, subject to consumer protections. Consumers are protected by a 5% cap on the amount of eligible investment in plant which UGI may recover through the DSIC surcharge. UGI's calculated

[9] Rebuttal Testimony of Paul R. Moul, p. 5.

achieved return on its DSIC eligible plant investment is compared to one of two benchmarks. The first benchmark is the utility's allowed ROE in a base rate case within two years. In the absence of a specific allowed ROE, the Commission's Quarterly Earnings Report identifies an industry ROE for use in the DSIC. The benchmark ROE serves as a guard against over-earnings. If UGI's calculated achieved return on its DSIC investment exceeds the applicable benchmark ROE, then UGI cannot collect the DSIC surcharge for the next quarter.

An ROE that is calculated in some way by Commission staff, for use in a single quarter test of whether a natural gas utility without a recent allowed cost of equity may be over-earning through its DSIC surcharge, is not suited to identification of the cost of common equity which UGI should be allowed the opportunity to earn as of the end of the FPFTY.

IV. Credibility of CAPM Results

Q. Please summarize Mr. Moul's surrebuttal testimony regarding your CAPM results.

A. Mr. Moul claims that the result of my CAPM is not credible.[10]

Q. Please summarize the inputs and results of your CAPM.

A. The CAPM is a Nobel-prize-winning financial model that has three inputs: (1) risk-free rate; (2) beta; and (3) the ERP. I will summarize and contrast the sources of these inputs between my CAPM and Mr. Moul's CAPM.

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[10] Rebuttal Testimony of Paul R. Moul p. 27, lines 14-15.

1. Risk-free rate

Financial analysts use the yield on Treasury securities as a proxy for the risk-free rate. I used a recent 30-day average on the daily yields on 30-year Treasury bonds as a proxy for the risk-free rate in my CAPM. This is a very reasonable approach. In contrast, Mr. Moul relies on projected bond yields. I have reviewed dozens of utility ROE testimony dating back more than 20 years. In nearly every one of those cases, the witness representing the utility will rely on a forward-looking or projected Treasury bond yield for the risk-free rate, instead of relying on the current, *known* Treasury bond yield. In every single one of those cases, I cannot recall a single instance in which the utility's projected bond yield was *lower* than the current bond yield. In other words, I cannot recall a single case in which a utility witness's prediction of the future did not, all else held constant, result in a higher cost of equity estimate in the present. After observing this tactic numerous times over many years without exception, it reinforces my opinion that it is preferable use known (current) bond yields rather than unknown (future) bond yields.

2. Beta

For the beta input in my CAPM, I relied on the betas published by Value Line. In my experience, the vast majority of ROE witness in utility rate proceedings (representing both utilities and customers) rely on Value Line betas without further adjustment. In contrast, Mr. Moul takes the unusual approach of adjusting Value Line's published betas. It is not surprising that this adjustment is in the upward direction.

2. ERP

Mr. Moul criticized me for looking back over 30 days to get an average yield on T-bonds for my risk-free rate and described it as "backward-looking."[11] In contrast, Mr. Moul relies on data that predates the invention of color televisions in his ERP estimate. Relying on data dating back to 1940 is not a reasonable approach in estimating the ERP.[12] As discussed in my direct testimony, there is substantial evidence showing that the current and forward-looking EPR is notably lower than the historical ERP (especially if one begins their historical ERP analyses just after the end of the Great Depression). In contrast to Mr. Moul's approach, I relied on a survey of thousands of unbiased experts in helping develop a reasonable estimate for the ERP. I also looked at the estimate published by Duff & Phelps (a respected, international corporate advising firm) and the estimate published by one of the world's leading experts on the ERP – Dr. Aswath Damodaran. The *highest* ERP from these sources is 5.5% (notably lower than Mr. Moul's 8.77% estimate). That is the ERP I used in my CAPM.

Q. Based on this summary, what do you conclude about the results on your CAPM analyses as compared with Mr. Moul's results?

A. I used reasonable figures for each of the three CAPM inputs. My inputs are not affected by biases. Indeed, there is very little of my own personal judgement injected into the CAPM results. The current risk-free rate is based on the current yields of Treasury bonds, which are known; it does not require a subjective estimate or adjustment. The betas I used are published by Value Line. To my knowledge, Value Line does not have any conflict of

[11] Rebuttal Testimony of Paul R. Moul, p. 27, line 17.

[12] UGI Gas Exhibit B, Sch. 12.

interest with either utilities or ratepayers that might affect their judgment. The ERP I used reflects the results from a survey of thousands of unbiased experts. Based on these inputs, the results of my CAPM are quite reasonable.

V. Leverage Adjustment

Q. Please summarize Mr. Moul's rebuttal testimony regarding his leverage adjustment.

A. Mr. Moul claims that I "never really refute" his leverage adjustment and that I employ his leverage adjustment approach through the use of a similar mathematical technique as part of my capital structure analysis.[13]

Q. What is your response to Mr. Moul's rebuttal testimony regarding the leverage adjustment?

A. First, Mr. Moul's claim that I "never really refute" his leverage adjustment is inaccurate. In my direct testimony, I stated that "Mr. Moul's proposed leverage adjustment is entirely unnecessary and inappropriate."[14] I also provided several reasons why I disagree with Mr. Moul's leverage adjustment. As discussed in my direct testimony, if we consider the effects of leverage in the cost of equity calculation, it indicates a cost of equity of about 7.6% at a 50% debt ratio for UGI.[15]

Q. What is the impact to the revenue requirement related to Mr. Moul′s proposed leverage adjustment?

A. If the Commission were to reject the Company's proposed leverage adjustment, it would reduce the revenue requirement by $23.755 million.

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[13] Rebuttal Testimony of Paul R. Moul, p. 22, lines 22-23.

[14] Direct Testimony of David J. Garrett, p.46, lines 4-5.

[15] Exhibit DJG-17.

VI. Management Performance Premium and Response to Mr. Brown's Testimony

Q. Please summarize Mr. Moul's rebuttal testimony regarding his premium for management performance.

A. Mr. Moul reaffirms his belief that 20 basis points should be added to the cost of equity estimate as additional compensation to shareholders for management performance.

Q. What is your response to the Company's rebuttal testimony regarding the management performance premium?

A. Mr. Moul states the premium should be 20 basis points. Mr. Brown states that it should be at the high end of Mr. Moul's recommended range. Regardless, I maintain the opinion stated in my direct testimony that the Commission should affirmatively reject any premium to either a cost of equity estimate or authorized ROE that is related to managerial performance. The market would have already accounted for the Company's past performance. Imposing additional costs on consumers, to reward UGI for giving away shareholder dollars or managing O&M expense since the last rate case does not benefit consumers who will have to pay the higher rates. I recommend that the Commission deny the Company's request.

Q. What is the impact to ratepayers that the management performance premium would have?

A. As addressed in the direct testimony of OCA witness Mugrace, an increase of 0.2% to the ROE for Mr. Moul's management performance premium would increase the revenue requirement by $4.9 million.

Q. Please summarize Mr. Brown's rebuttal testimony directed at your direct testimony.

A. Mr. Brown states that there are a few errors in my testimony related to references I made to "UGI Gas" case, but the citations were to a case involving PECO Energy Company ("PECO").[16]

Q. Do you have a response to Mr. Brown's assertions?

A. Yes. There are a few typographical errors in my direct testimony related to this issue. The references made to UGI Gas on page 70, lines 11-17 (and corresponding citations), are meant to refer to PECO, as noted in Mr. Brown's rebuttal testimony.

Q. Mr. Brown makes several assertions related to inflation and its impact on the Company's proposals related to cost of capital and other costs. Do you have a response?

A. Yes. First, while it is not surprising to see many utility representatives around the country use the current inflationary environment as part of its support for rate increases, it is important for regulators to keep in mind that inflation impacts customers as well. I would argue that the adverse impacts of inflation are felt more by customers than by UGI's institutional shareholders. More importantly, the cost of equity models I employed in this case account for the impacts of inflation on current market conditions. Thus, we have an objective way to consider the quantitative impacts of inflation, rather than relying on the general narrative statements made by Mr. Brown or any other witness.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

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[16] Rebuttal Testimony of Christopher R. Brown, p. 8, lines 13-26.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, David J. Garrett, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 2SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2022
*329517

Signature: ____________________
David J. Garrett

Consultant Address: Resolve Utility Consulting, PLLC
101 Park Avenue
Suite 1125
Oklahoma City, OK 73102

OCA Statement 3SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)))	
v.	)	Docket No. R-2021-3030218
UGI UTILITIES, INC. – GAS DIVISION	)))	

SURREBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 27, 2022

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement 3 on April 20, 2022, and my rebuttal testimony was submitted as OCA Statement 3R on May 17, 2022.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to certain aspects of the rebuttal testimony of UGI Utilities Inc. – Gas Division ("UGI Gas" or "Company") witnesses Constance E. Heppenstall, Sherry A. Epler, Christopher R. Brown, and John D. Taylor; and Office of Small Business Advocate ("OSBA") witness Robert D. Knecht.

II. UGI GAS

WITNESS: Constance E. Heppenstall

Q. MS. HEPPENSTALL CLAIMS THAT SHE USED THE AVERAGE AND EXCESS METHOD IN HER COST-OF-SERVICE STUDY BECAUSE IT WAS ACCEPTED BY THE COMMISSION IN PECO ENERGY COMPANY ("PECO") DOCKET NO. R-2020-3018929.[1] WHAT IS YOUR RESPONSE?

[1] Rebuttal Testimony of Constance E. Heppenstall, UGI Gas Statement No. 10-R, p. 3.

A. The Commission's Order in the PECO proceeding was issued in 2021. In an Order issued by the Commission earlier in 2021 in Columbia Gas of Pennsylvania, Inc. ("Columbia") Docket No. 2020-3018835, the Commission accepted the use of the Peak and Average ("P&A") method.[2] In the PECO Order the Commission indicated that it does not have a standard cost of service methodology, and that it intends to evaluate the appropriate cost of service method for a natural gas distribution company ("NGDC") on a case-by-case basis.[3]

Q. MS. HEPPENSTALL CLAIMS THAT THE P&A METHOD IS FLAWED BECAUSE IT COUNTS AVERAGE DEMANDS TWICE. WHAT IS YOUR RESPONSE?

A. Mr. Knecht raised the same claim in his direct testimony, and I addressed this claim in my rebuttal testimony on pages 6-7, finding the double count claim to be incorrect and misleading.[4]

Q. IN YOUR DIRECT TESTIMONY, YOU ALLOCATED EXCESS CAPACITY RELATED COSTS TO INTERRUPTIBLE CUSTOMERS. DOES MS. HEPPENSTALL AGREE WITH YOUR ALLOCATION?

A. No. Ms. Heppenstall claims that it is inappropriate to allocate excess capacity or peak demand related costs to interruptible customers because interruptible customers can be interrupted during periods of peak demand.[5]

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[2] Opinion and Order, Docket No. 2020-3018835, Order Entered February 19, 2021 ("Columbia Order"), at 218.

[3] Non-Proprietary Version Opinion and Order, Docket No. R-2020-3018929, Order Entered June 22, 2021 ("PECO Order"), at 230-231.

[4] Rebuttal Testimony of Jerome D. Mierzwa, OCA Statement 3R, at 6-7.

[5] Rebuttal Testimony of Constance E. Heppenstall, UGI Gas Statement No. 10-R, p. 6.

Q. WHAT IS YOUR RESPONSE TO MS. HEPPENSTALL'S CLAIM CONCERNING THE ALLOCATION OF EXCESS CAPACITY COSTS TO INTERRUPTIBLE CUSTOMERS?

A. First, as explained in my direct testimony, the A&E method is presented and described in *Gas Rate Fundamentals*.[6] As shown in Table 1 of my direct testimony, assigning no peak demand related costs to interruptible customers is inconsistent with the use of the A&E method presented in *Gas Rate Fundamentals*.

Second, in UGI Gas' most recent base rate proceeding in Docket No. R-2019-3015162, the Company presented an A&E cost of service study that was sponsored by Mr. Paul R. Herbert, who like Ms. Heppenstall, was from Gannett Fleming Valuation and Rate Consultants, LLC. In responding to Mr. Knecht in UGI Gas' prior proceeding, Mr. Herbert acknowledged that 105 of the 371 interruptible customers being served by the Company were in essence receiving firm service. He claimed that including these 105 customers in his cost-of-service study as firm customers would increase the Rate IS cost of service by $1.035 million. In evaluating the cost of service impact of considering these 105 Rate IS customers as firm customers, Mr. Herbert assigned a peak day demand of 40,944 Mcf to Rate IS.[7] In the cost of service study presented in my direct testimony, I assigned a peak day demand of 39,847 Mcf to Rate IS.[8] The difference between the peak day assignment for Rate IS I have proposed and what Mr. Herbert contended would be appropriate to recognize the firm nature of Rate IS service is immaterial. It is unlikely that the Company's system operations have changed significantly from the Company's last base proceeding with respect to interrupting

[6] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 6.

[7] Workpapers of the Rebuttal Testimony of Paul R. Herbert, UGI Gas Statement No. 8-R, Docket No. R-2019-3015162.

[8] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 27.

interruptible customers. Therefore, in addition to being reasonable for the reasons presented in my direct testimony, my proposed assignment of peak day demand to Rate IS is also supported by the firm nature of the service provided to certain Rate IS customers.

Q. IN YOUR DIRECT TESTIMONY YOU CLAIMED THAT MS. HEPPENSTALL'S A&E METHOD EQUATES TO USING A PEAK ALLOCATION.[9] DID MS. HEPPENSTALL AGREE WITH YOUR CLAIM?

A. No. Ms. Heppenstall contends that my claim is simply wrong, and for the Residential class her A&E allocation factor is 3.37% percent less than a peak allocation factor.[10]

Q. WHAT IS YOUR RESPONSE TO MS. HEPPENSTALL?

A. As demonstrated in my direct testimony, when there is no diversity in peak load on a natural gas distribution company's system such as the UGI Gas' system, the A&E method is identical to an allocation based solely on peak demands.[11] As also explained in my direct testimony, Ms. Heppenstall's application of the A&E method differs slightly from a pure peak allocation only because she has included the average usage of Rate IS customers and excluded the peak demand of Rate IS customers.[12]

Q. ALTHOUGH MS. HEPPENSTALL AGREES WITH YOUR PROPOSED REVISIONS TO THE ALLOCATION OF FORFEITED DISCOUNTS AND RECONNECTION FEES, SHE DISAGREES WITH YOUR PROPOSED MODIFICATION TO THE ALLOCATION OF MANUFACTURED GAS

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[9] *Id*., pp. 11-13.

[10] Rebuttal Testimony of Constance E. Heppenstall, UGI Gas Statement No. 10-R, p. 7.

[11] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 10.

[12] *Id*., p. 13.

REMEDIATION EXPENSES.[13] WHY DOES SHE DISAGREE WITH THIS MODIFICATION?

A. Ms. Heppenstall acknowledges that these remediation expenses are related to manufactured gas plants ("MGPs") that have been long retired and no longer produce gas supply. She contends that if these MGPs were still in operation, the gas produced and the associated costs would be included in the Company's Purchased Gas Cost ("PGC") calculation related to core market Residential and small firm service. This is because, historically, the MGPs were overwhelmingly used to provide gas supply to Residential and small commercial customers, rather than industrial customers.[14]

Q. WHAT IS YOUR RESPONSE TO MS. HEPPENSTALL'S CLAIMS CONCERNING THE ALLOCATION OF MGP REMEDIATION EXPENSES?

A. I agree with Ms. Heppenstall that if UGI Gas' MGPs were in operation today, the gas produced would be included in the Company's PGC calculation related to core market Residential and small firm service. However, UGI Gas' MGPs ceased operations in 1955, which was 67 years ago. It is highly unlikely that any current Residential or small firm service customer was a customer of UGI Gas 67 years ago. Therefore, it is inappropriate to solely recover MGP remediation expenses from Residential and small firm service customers. It would be more appropriate to deny UGI Gas recovery of these costs since MGPs are not currently used and useful in the provision of utility service.

Q. IN HER REBUTTAL TESTIMONY, MS. HEPPENSTALL INCLUDES A STATEMENT FROM THE COMMISSION'S ORDER IN THE PECO

[13] Rebuttal Testimony of Constance E. Heppenstall, UGI Gas Statement No. 10-R, pp. 7-8.

[14] *Id*.

PROCEEDING.[15] ARE THERE OTHER STATEMENTS IN THAT ORDER THAT ARE RELEVANT TO THE ISSUES IN THIS PROCEEDING?

A. Yes, In the PECO Order the Commission found that the P&A method is a reasonable method to utilize in a cost-of-service study for an NGDC.[16] In addition, the Commission found:

> Therefore, we conclude that the excess demand component of PECO'S distribution mains system garners considerable weight in the balance of mains costs.[17]

Q. WHAT IS YOUR RESPONSE TO THIS FINDING IN THE PECO PROCEEDING?

A. This statement implies that peak demands were given considerable weight by the Commission in the allocation of mains costs in the PECO proceeding. In this proceeding, in my direct testimony, I have demonstrated that on the UGI Gas system, only approximately 10% of distribution mains costs are associated with meeting peak demand requirements.[18] Therefore, the excess demand component of UGI Gas' distribution mains system does not garner the considerable weight it was given in the PECO proceeding.

Q. DID MS. HEPPENSTALL PRESENT A REVISED COST OF SERVICE STUDY IN THE REBUTTAL TESTIMONY?

A. Yes. Ms. Heppenstall presents a revised cost of service study in her rebuttal testimony reflecting the following changes to the study filed in her direct testimony:

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[15] *Id.*, p. 4.

[16] PECO Order, at 230.

[17] PECO Order, at 229.

[18] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 23.

- A revised split of costs in FERC Account 874;
- A revised allocation of reconnection fees and forfeited discounts based on the most recent data available;
- A revised allocation of the costs identified as MGP remediation costs in Accounts 923 and 930; and
- A revised allocation of the design day demand for Rate R/RT and Rate N/NT customers.[19]

Q. DID THE COST-OF-SERVICE STUDY PRESENTED IN YOUR DIRECT TESTIMONY REFLECT ANY OF MS. HEPPENSTALL'S REVISIONS?

A. Yes. The study I filed in my direct testimony already reflected the revised split of costs in FERC Account 874, and the revised allocation of reconnection fees and forfeited discounts.[20] I would note that Ms. Heppenstall claims that the costs in Account 874 should be allocated 55.08% to mains and 44.92% to services.[21] However, her revised cost of service study allocated 55.08% of Account 874 costs to services and 44.92% to mains. A corrected cost of service study was filed by the Company on May 24, 2022. As also just explained, I continue to disagree with Ms. Heppenstall's allocation of MGP remediation costs. The study I presented in my direct testimony did not reflect the revised allocation of design day demand for Rate R/RT and Rate N/NT. I present a study which reflects this revised allocation for Rate R/RT and Rate N/NT later in my surrebuttal testimony.

Q. IN YOUR DIRECT TESTIMONY, YOU RECOMMENDED THAT UGI GAS' PROPOSED RESIDENTIAL MONTHLY CUSTOMER CHARGE OF $19.95 BE REJECTED, AND THAT THE MONTHLY CUSTOMER

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[19] Rebuttal Testimony of Constance E. Heppenstall, UGI Gas Statement No. 10-R, p. 2.

[20] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 30.

[21] Rebuttal Testimony of Constance E. Heppenstall, UGI Gas Statement No. 10-R, p. 2.

CHARGE FOR RESIDENTIAL CUSTOMERS BE INCREASED TO NO HIGHER THAN $16.00.[22] DID MS. HEPPENSTALL AGREE WITH THIS RECOMMENDATION?

A. No. Ms. Heppenstall claims a cost-based monthly customers charge for Residential customers is $27.79 and, therefore, the proposed charge of $19.95 is justified.[23]

Q. WHAT IS YOUR RESPONSE TO MS. HEPPENSTALL?

A. As explained in my direct testimony, to provide for constancy and uniformity with the monthly Residential customer charges of other Pennsylvania NGDCs, to provide for gradualism, and to promote energy conservation, the monthly customer charge for Residential customers should be increased to no higher than $16.00.[24]

III. <u>UGI GAS</u>

WITNESS: Sherry A. Epler

Q. IN YOUR DIRECT TESTIMONY YOU FOUND THAT THE COMPANY'S PROPOSED REVENUE ALLOCATION TO BE UNREASONABLE AND THAT THE REVENUE ALLOCATION SHOULD BE BASED ON YOUR P&A COST-OF-SERVICE STUDY.[25] DOES MS. EPLER AGREE?

A. No. Ms. Epler contends that, based on the testimony of Ms. Heppenstall, the P&A cost of service I present in this proceeding should not be adopted by the Commission and, therefore, my proposed revenue allocation should also not be adopted.[26]

Q. WHAT IS YOUR RESPONSE?

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[22] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 38.

[23] Rebuttal Testimony of Constance E. Heppenstall, UGI Gas Statement No. 10-R, p. 10.

[24] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 36.

[25] *<u>Id.</u>*, pp. 32-33.

[26] Rebuttal Testimony of Sherry A. Epler, UGI Statement No. 8-R, p. 13.

A. In my direct and rebuttal testimony, I have demonstrated that the A&E cost of service study method presented by Ms. Heppenstall does not present an accurate indication of class allocated cost responsibilities, and that the P&A method is consistent with established cost of service precedent. Therefore, the P&A method should be utilized to determine the revenue allocation in this proceeding.

Q. IN YOUR DIRECT TESTIMONY YOU RECOMMENDED THAT THE RESIDENTIAL CUSTOMER CHARGE BE INCREASED TO NO MORE THAT $16.00.[27] WHAT WAS THE BASIS FOR THAT RECOMMENDATION?

A. In this proceeding the Company is proposing to increase the Residential customer charge from $14.60 to $19.95, or 37%. As previously explained, I recommended that the Residential customer charge be increased to no more than $16.00 because the Company's proposal: (1) is out of line with the Residential customer charges of other NGDCs in Pennsylvania; (2) violates the principle of gradualism; and (3) is inconsistent with the Commission's goal of fostering energy conservation.[28] I further noted that a higher customer charge may counter the effectiveness of the Company's proposed Energy Efficiency and Conservation ("EE&C") Plan as it limits the amount of potential bill savings through the reduction of variable charges, which may in turn, discourage ratepayers from implementing energy conservations measures.[29]

Q. MS. EPLER CLAIMS THAT THE COMPARISON BETWEEN UGI GAS' PROPOSED RESIDENTIAL CUSTOMER CHARGE AND THE CUSTOMER CHARGES OF OTHER NATURAL GAS UTILITIES IN

[27] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 38.

[28] *Id.*, p. 36.

[29] *Id.*, pp. 37-38.

PENNSYLVANIA SHOULD NOT DETERMINE THE REASONABLENESS OF UGI GAS' PROPOSED CUSTOMER CHARGE FOR RESIDENTIAL CUSTOMERS.[30] WHAT IS YOUR RESPONSE?

A. In my direct testimony, I noted the principles of a sound rate structure. These principles included understandability and public acceptability.[31] Under the Company's Residential customer charge proposal, UGI Gas' charge would be well in excess of the charge of any other Pennsylvania NGDC.[32] It is unlikely that a UGI Gas Residential customer comparing their rates to those of other Pennsylvania NGDCs would find the customer charge rate difference to be understandable or acceptable.

Q. MS. EPLER DISAGREES WITH YOUR CLAIM THAT THE COMPANY'S PROPOSED $19.95 RESIDENTIAL CUSTOMER CHARGE IS INCONSISTENT WITH THE CONCEPT OF GRADUALISM.[33]

A. Ms. Epler claims that the concept of gradualism should apply to the overall rate increase, not individual rate components. UGI Gas' proposed customer charge reflects an increase of 37%. While on average UGI Gas' overall rate design may provide for gradualism, it would not provide for gradualism for customers with lower usage levels. In assessing the need for gradualism, the impact of the increases on customers with a range of usage levels should be considered, as well as average use customers.

Q. MS. EPLER CONTENDS THAT THE COMPANY'S PROPOSED INCREASE IN THE RESIDENTIAL CUSTOMER CHARGE WOULD NOT

[30] Rebuttal Testimony of Sherry A. Epler, UGI Statement No. 8-R, pp. 17-18.

[31] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 32.

[32] ***Id***., pp. 36-37.

[33] Rebuttal Testimony of Sherry A. Epler, UGI Gas Statement No. 8-R, pp. 19-20.

DISCOURAGE RATEPAYERS FROM IMPLEMENTING ENERGY CONSERVATION MEASURES. DO YOU AGREE?

A. No. Any increase in a customer charge would discourage ratepayers from implementing energy conservation measures when compared to maintaining or minimizing the increase in customer charges. As explained by the Maryland Public Service Commission:

> Even more to the point, however, recovery through fixed customer charges is inconsistent as a matter of policy with …energy efficiency and conservation…Capturing this incremental revenue in volumetric charges leaves customers entirely in control of their usage and charges, and thus leaves each individual customer in control of the extent (if any) to which this modest rate increase affects him or her. Accordingly, we reject the Company's request to increase customer charges and direct it to recover all incremental revenues through volumetric charges.[34]
>
> In arriving at this increase, the Commission places emphasis on Maryland's public policy goals that intend to encourage energy conservation. Maintaining relatively low customer charges provides customers with greater control over their heating bills by increasing the value of volumetric charges. No matter how diligently customers might attempt to conserve energy or respond to pricing incentives, they cannot reduce fixed service charges.[35]
>
> However, in this case we believe that holding the line on gas customer charges during the rate-effective period for this case will permit gas customers to have better control of their gas bills,

[34] Order No. 83085 at pp. 53-54, *In the Matter of the Application of Delmarva Power and Light Company for an Increase in its Retail Rates for the Distribution of Electric Energy*, 2019 (ML 120754) (Case No. 9192).

[35] Order No. 88944, p. 131, *in the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and to Revise its Terms and Conditions for Gas Service*, 2018 (ML 223208) (Case No. 9481).

> allowing them the opportunity to wisely manage their gas usage. This decision is also keeping the Commission precedent.[36]

Q. MS. EPLER RECOMMENDS THAT, IF YOUR $16.00 RESIDENTIAL CUSTOMER CHARGE IS APPROVED BY THE COMMISSION, IT SHOULD NOT BE SCALED BACK TO REFLECT THE ACTUAL INCREASE AUTHORIZED BY THE COMMISSION IN THE PROCEEDING?[37] WHAT IS YOUR RESPONSE?

A. Scaling back the $16.00 Residential customer charge to reflect the increase authorized by the Commission would further ensure gradualism and further promote the Commission's goal of fostering energy conservation.

Q. IN YOUR DIRECT TESTIMONY YOU PROPOSED MODIFICATIONS TO THE DESIGN OF THE CHARGES FOR RATES NNS AND MBS. PLEASE SUMMARIZE THOSE MODIFICATIONS.

A. For Rate NNS, I proposed that the storage trip charge should be adjusted to include demand charges.[38] For Rate MBS, I recommended that daily deliverability demand charges be included in designing the applicable charges, and that the monthly imbalance percentage be increased to 5 percent.[39]

Q. DOES MS. EPLER AGREE WITH YOUR RECOMMENDATION TO INCLUDE DEMAND CHARGES IN DESIGNING THE APPLICABLE RATES FOR RATE NNS AND MBS?

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[36] Order No. 68706 at pp. 195-96, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*, 2016 WL 7011611 (Case No. 9406, June 2016) (citations omitted).

[37] Rebuttal Testimony of Sherry A. Epler, UGI Statement No. 8-R, p. 21.

[38] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 4, p. 40.

[39] *Id*., p. 42.

A. No. Ms. Epler claims that the same storage assets are used to provide both NNS and MBS service. Therefore, one must look at the full contribution non-choice transportation customers make toward the cost of the interstate pipeline storage resources by considering the revenue paid under both Rate NNS and Rate MBS to determine if any underpayment for the services is being made by non-choice transportation customers. Ms. Epler then presents an analysis which indicates additional storage demand costs should not be assigned to Rate NNS.[40]

Q. WHAT IS YOUR RESPONSE TO MS. EPLER'S TESTIMONY CONCERNING THE ASSIGNMENT OF STORAGE DEMAND CHARGES TO RATE NNS AND MBS?

A. The design of the rates for service under Rates NNS and MBS has been an issue in prior UGI Gas base rate proceedings in which I have participated on behalf of the OCA. This is the first proceeding in which the Company has advanced this argument concerning the assignment of demand charges to Rate NNS. At this point in this proceeding, I will no longer pursue the allocation of storage demand charges to Rate NNS.

Q. DOES MS. EPLER AGREE WITH YOUR PROPOSAL TO DESIGN THE CHARGES FOR RATE MBS BASED ON AN IMBALANCE PERCENTAGE OF 5%?

A. No. Ms. Epler contends that the charge for service under Rate MBS should be based on actual average annual monthly imbalances which is 2.5737% rather than the 5% permitted tolerance.[41]

Q. WHAT IS YOUR RESPONSE?

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[40] Rebuttal Testimony of Sherry A. Epler, UGI Statement No. 8-R, pp. 22-25.

[41] *Id.*, pp. 25-26.

A. Customers should be charged for the level of service they are entitled to and, therefore, it is appropriate to design the MBS rate based on the 5% percent tolerance. For example, customers under Rates LFD and XD are charged for the maximum daily quantity of service they are entitled to. These charges are not reduced if a customer does not utilize their maximum daily service entitlement. Similarly, PGC customers are charged for interstate pipeline capacity costs based on their expected design day demands, not their actual demands.

IV. UGI GAS

WITNESS: Christopher R. Brown

Q. IN YOUR DIRECT TESTIMONY, YOU RECOMMENDED THAT THE COMPANY INCREASE THE CAPACITY RELEASE CHARGE FOR RATE XD CUSTOMERS TO REFLECT THE COMPANY'S WEIGHTED AVERAGE COST OF DEMAND ("WACOD") CALCULATION IN EFFECT FOR LFD CUSTOMERS RATHER THAN THE COST OF COLUMBIA GAS TRANSMISSION ("COLUMBIA') FIRM TRANSPORTATION ("FT") CAPACITY ONCE THE CURRENT CONTRACTS WITH RATE XD CUSTOMERS EXPIRE.[42] DOES MR. BROWN AGREE WITH YOUR RECOMMENDATION?

A. No. Mr. Brown claims that increasing capacity charges to Rate XD customers could result in these customers leaving the Company's distribution system or perhaps more likely, demanding a reduction to the base distribution charges they currently pay. Mr. Brown also contends that Rate XD customers employ thousands of people that work in

[42] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 3, p. 43.

the Company's service territory and may move their business operations to other locations, resulting in economic implications to UGI Gas' customers.[43]

Q. WHAT IS YOUR RESPONSE TO MR. BROWN'S CLAIMS CONCERNING YOUR RECOMMENDATION TO RELEASE CAPACITY TO RATE XD CUSTOMERS BASED ON THE WACOD APPLICABLE TO LFD CUSTOMERS?

A. UGI Gas' PGC customers pay the Company's WACOD for the firm interstate pipeline capacity required to provide sales service. Choice and certain traditional (non-Choice) transportation customers accept an assignment of interstate pipeline capacity from UGI Gas, and the price paid for the assigned capacity is based on UGI Gas' WACOD. Not all traditional transportation customers accept an assignment of UGI Gas' interstate pipeline capacity. Rate XD customers that accept an assignment of Columbia Gas capacity from UGI Gas pay less than UGI Gas' WACOD for that capacity. The current cost of Columbia Gas from transportation capacity is $9.8100 per Dth per month, or $117.72 Dth per year. UGI Gas currently releases 49,773 Dth per month of Columbia Gas capacity to Rate XD customers.[44] UGI Gas' current WACOD for firm transportation capacity assigned to other transportation customers is approximately $15.00 per Dth per month.[45] There is no basis to discriminate between what UGI Gas' sales and transportation customers pay for firm interstate pipeline capacity. The assignment of Columbia Gas capacity to Rate XD customers results in an unreasonable and discriminatory discount of approximately $3.1 million that is paid for by sales and

[43] Rebuttal Testimony of Christopher R. Brown, UGI Statement No. 1-R, pp. 32-33.

[44] Response to OCA-I-17.

[45] Response to OCA-I-43.

transportation customers that accept an assignment of capacity from UGI Gas (49,733 Dth x ($15.00 - $9.81) x 12 months).

Mr. Brown claims that adopting my recommendation concerning the assignment of capacity to Rate XD customer could possibly result in subsequent reductions in base rate revenues from Rate XD customers.[46] That is certainly possible. However, adopting my capacity assignment pricing recommendation would result in these additional discounts, and the assigned capacity cost discount, being recovered more equitably from all customers. This is because under my proposal, transportation customers that do not accept an assignment of capacity would bear some responsibility for the capacity cost and distribution charge discounts granted to Rate XD customers.

Q. DOES MR. BROWN PRESENT ANY EVIDENCE THAT IT IS A LIKELY SCENARIO FOR ANY RATE XD CUSTOMER CURRENTLY RECEIVING AN ASSIGNMENT OF COLUMBIA GAS FIRM TRANSPORTATION CAPACITY TO MOVE THEIR BUSINESS OPERATIONS IF THEY ARE NO LONGER ASSIGNED COLUMBIA GAS FIRM TRANSPORTATION CAPACITY?

A. No. As just indicated, there are currently 15 Rate XD customers that are released a total of 49,773 Dth per day of Columbia FT capacity. As also just indicated, based on the current cost difference between Columbia Gas firm transportation capacity and the WACOD that would be applicable under my recommendation, without any subsequent off setting distribution base rate discounts, the annual cost for gas service from UGI Gas for these 15 Rate XD customers would increase by approximately $3.1 million. Based on the current usage characteristics of Rate XD customers reflected in UGI Gas'

[46] Rebuttal Testimony of Christopher R. Brown, UGI Statement No. 1-R, p. 33.

cost of service study, adopting my recommendation to assess Rate XD customers the Rate LFD WACOG would increase the average cost of gas for a Rate XD customer by approximately 24 cents per Dth.[47] This seems to be an insufficient incentive for a Rate XD customer to move their business operations. I would further note that Mr. Brown has also presented no evidence that there are location options available to Rate XD customers where the cost of natural gas service would be comparable to their current service costs.

V. <u>UGI GAS</u>

WITNESS: John D. Taylor

Q. IN YOUR DIRECT TESTIMONY YOU RECOMMENDED THAT UGI GAS' PROPOSED WEATHER NORMALIZATION ADJUSTMENT ("WNA") NOT BE APPROVED, BUT IF IT WERE TO BE APPROVED, A 3% DEAD BAND SHOULD BE INCLUDED SIMILAR TO THE PILOT WNA OF COLUMBIA GAS OF PENNSYLVANIA, INC.[48] DOES MR. TAYLOR AGREE THAT, IF APPROVED, UGI GAS' WNA SHOULD INCLUDE A 3% DEAD BAND?

A. No. Mr. Taylor contends that a dead band would add an unnecessary level of complexity for the Company's administration and communication related to the WNA,

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[47] As previously indicated, the cost difference between Columbia Gas firm transportation capacity and the recommended Rate LFD WACOG is approximately $5.19 ($15.00 - $9.81). The amount of capacity currently assigned to Rate XD customers is 49,733 Dth per day. The Company's cost of service study indicates that Rate XD customers operate at a 70 percent load factor. Therefore:

a. Lost Capacity Discount: 49,733 Dth x $5.19 x 12 = $3,099,862
b. Rate XD Volumes: 49,733 Dth x 365 x 70 percent = 12,717,002 Dth
c. Rate Impact: a/b = 24.4 cents per Dth.

[48] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 4, p. 53.

as well as to the understanding of the mechanics of the WNA for customers. Therefore, the Commission should reject the application of the dead band in approving WNA.[49]

Q. WHAT IS YOUR RESPONSE TO MR. TAYLOR?

A. In Columbia Docket No. R-2018-2647577, a Settlement Agreement was approved which reduced Columbia's WNA dead band from 5% to 3%. In Docket No. R-2020-3018835, Columbia subsequently proposed to eliminate the 3% dead band. Columbia proposed eliminating the dead band because it claimed it ignored the true effect of weather, and would simplify the administration of a proposed Revenue Normalization Adjustment ("RNA"). The proposed RNA would adjust variations in revenues due to factors other than weather. The additional complexity for administration as well as the understanding of the mechanics of the WNA for customers was not cited by Columbia as a reason for eliminating the dead based. The Recommend Decision ("RD") of the Administrative Law Judge ("ALJ") in Docket No. R-2020-3018835 found that the 3% dead band was a reasonable provision, because it allowed for a range of what is considered "[n]ormal" weather in which Columbia's Commission approved rates would be applied without adjustment. The Commission's Order in Docket No. R-2020-3018835 adopted the ALJ's recommendation on this topic in the RD.[50]

Q. ONE OF THE FACTORS YOU CITE IN SUPPORT OF ADOPTING A DEAD BAND IS THAT USAGE CAN BE AFFECTED BY VARIABLES OTHER THAN TEMPERATURE.[51] DOES MR. TAYLOR AGREE?

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[49] Rebuttal Testimony of John D. Taylor, UGI Statement No. 11-R, p. 4.

[50] Opinion and Order, Docket No. 2020-3018835, at 264-265.

[51] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 4, p. 53.

A. Yes. Mr. Taylor agrees that usage can be impacted by variables other than temperature much as humidity, wind speed, precipitation, and cloud cover.[52]

Q. CITING BONBRIGHT'S, "CRITERIA OF A SOUND RATE STRUCTURE," MR. TAYLOR AGAIN CLAIMS THAT A DEAD BAND ADDS COMPLEXITY AND INCONSISTENCY TO THE WNA.[53] WHAT IS YOUR RESPONSE?

A. The Company has presented no evidence that a dead band would add complexity and inconsistency that would result in customer confusion. Columbia and Philadelphia Gas Works have been operating under WNA's with dead bands for a number of years without evidence of there being customer confusion. In addition, a dead band is consistent with Commission precedent as it provides protection to customers against the unnecessary reconciliation of day-to-day temperature variations that are a part of normal business.[54]

Q. IN YOUR DIRECT TESTIMONY YOU FOUND THAT THE PROPOSED WNA EMBODIES A TAKE-OR-PAY POLICY.[55] WHAT WAS MR. TAYLOR'S RESPONSE?

A. In my direct testimony, I found that the proposed WNA embodies a take-or-pay policy because under the WNA customers would pay for a normalized level of distribution service regardless of their actual usage. Mr. Taylor claims that when the weather is colder than normal, customers use more gas, but do not purchase more distribution

[52] Rebuttal Testimony of John D. Taylor, UGI Statement No. 11-R, p. 5.

[53] ***Id.***, pp. 6-7.

[54] Columbia Gas of Pennsylvania, Inc,, Docket No. R-2020-3018835, Opinion and Order, at 264.

[55] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 4, pp. 50-51.

service, and when the weather is warmer than normal customers use less gas, but do not purchase less distribution service.[56]

Q. WHAT IS YOUR RESPONSE TO MR. TAYLOR?

A. Mr. Taylor's claim is simply wrong. UGI Gas provides gas distribution service and customers are charged for distribution service based on their gas usage. Therefore, the amount of distribution service provided by UGI Gas and charged to a customer will be higher when weather is colder than normal and lower when weather is warmer than normal.

Q. IN YOUR DIRECT TESTIMONY YOU INDICATED THAT THE WNA INAPPROPRIATELY AUTOMATICALLY ADJUSTS REVENUES BETWEEN RATE CASES WITHOUT CONSIDERING OTHER CHANGES IN TOTAL REVENUES AND COSTS.[57] WHAT IS MR. TAYLOR'S RESPONSE?

A. Mr. Taylor finds my claim to be an unreasonable critique of the WNA.[58] However, he does not dispute my conclusion.

Q. IN YOUR DIRECT TESTIMONY YOU CLAIM THAT AN NGDC'S "O&M" EXPENSES WOULD TEND TO INCREASE AS DEMAND INCREASES UNDER COLDER-THAN-NORMAL WEATHER, AND TEND TO DECLINE AS DEMAND DECREASES UNDER WARMER-THAN-NORMAL WEATHER.[59] WHAT IS MR. TAYLOR'S RESPONSE?

A. Mr. Taylor claims I have provided no evidence of this relationship.[60]

[56] Rebuttal Testimony of John D. Taylor, UGI Statement No. 11-R, pp. 16-17.
[57] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 4, p. 51.
[58] Rebuttal Testimony of John D. Taylor, UGI Statement No. 11-R, p. 18.
[59] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 4, p. 51.
[60] Rebuttal Testimony of John D. Taylor, UGI Statement No. 11-R, p. 19.

Q. WHAT IS YOUR RESPONSE TO MR. TAYLOR?

A. Customer demands increase as temperature decreases, and utilization of the UGI Gas distribution system increases as customer usage increases. It is reasonable and logical to expect that O&M expenses would increase as utilization of UGI Gas' distribution system increases. Mr. Taylor has presented no evidence that O&M expenses are not affected by distribution system utilization.

Q. IN HIS DIRECT TESTIMONY, MR. TAYLOR RESPONDED TO EACH OF THE 14 CONSIDERATIONS OUTLINED IN THE COMMISSION'S STATEMENT OF POLICY ON ALTERNATIVE RATEMAKING AND IN YOUR DIRECT TESTIMONY YOU ADDRESSED EACH OF MR. TAYLOR'S RESPONSES.[61] DOES MR. TAYLOR PROVIDE AN ADDITIONAL RESPONSE TO ANY OF THOSE CONSIDERATIONS?

A. Yes. Mr. Taylors presents an additional response to Considerations 10, 12, 13 and 14. Below, I identify each of these four Considerations, the Company's initial response, my response to the Company's initial response, Mr. Taylor's rebuttal testimony response to my initial response, and my response to Mr. Taylor's rebuttal testimony response:[62]

Consideration 10	Please explain how the WNA impacts the frequency of rate case filings and affects regulatory lag.
	<u>Initial UGI GAS</u>: The WNA is not anticipated to impact the frequency of rate cases or have an impact on regulatory lag.

[61] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 4, pp. 45-50.

[62] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 4, pp. 45-50; Rebuttal Testimony of John D. Taylor, UGI Statement No. 11-R, pp. 24-26.

	Initial OCA: A reduction to the frequency of rate case filings would be a benefit of an alternative ratemaking mechanism. The WNA does not provide this benefit.
	Rebuttal UGI Gas: As an alternative ratemaking proposal, the WNA is not a mechanism which is intended to reduce the frequency of rate case filings.
	Surrebuttal OCA: Mr. Taylor does not dispute my initial claim.
Consideration 12	Please explain whether the WNA includes appropriate consumer protections.
	Initial UGI GAS: The WNA mechanism will result in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates. UGI Gas will not recover additional distribution revenues due to colder than average temperatures that result in higher-than-normal usage from customers.
	Initial OCA: The WNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony.
	Rebuttal UGI Gas: The WNA mechanism insulates customers from high bills during colder-than-normal months, while also limiting a decline in distribution revenues for UGI Gas during warmer-than-normal months. In particular, WNA bills will be otherwise lower than non-WNA bills during colder than normal periods. These cold periods are the most sensitive to customers since they stand to create the largest burden to customers. Thus, inherent in the application of a WNA is this "consumer protection" against the burdens cold weather bills can produce. There are no further consumer protections required, as this is a balance in risk and reward sharing between UGI Gas and UGI Gas's customers.
	Surrebuttal OCA: Customers already have a budget billing option to reduce the volatility of their gas utility bills. Budget billing provides greater stability in a customer's gas utility bill than would the WNA because it provides for levelized billing in winter months regardless if it's warmer or colder than normal.

Consideration 13	Please explain whether the WNA is understandable to customers.
	Initial UGI GAS: UGI Gas' WNA is not a new concept to the regulated utility industry. Similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. UGI Gas has proposed a WNA tariff that provides detailed information to the customer of how the mechanism works based on successful working versions found in the tariffs of other Pennsylvania natural gas distribution companies that have implemented a WNA tariff. Further, educational materials and customer service training will be developed upon approval of the mechanism, as well as appropriate notice being provided to customers related to the WNA being approved pursuant to the Commission's alternative ratemaking notice requirements.
	Initial OCA: UGI has not provided any evidence to indicate that the WNA will be understandable to customers.
	Rebuttal UGI Gas: UGI Gas's proposed WNA mechanism is similar to that implemented by Columbia, PGW, and other utilities across the United States. UGI Gas's proposed WNA mechanism adjusts current billings on a monthly billing basis as the bill is being calculated and issued, helping with customer understanding.
	Surrebuttal OCA: First, Mr. Taylor's response is inconsistent with the testimony of UGI Gas witness Ms. Epler. Ms. Epler contends that UGI Gas' customer charges should not be compared to those of other NGDCs, but Mr. Taylor contends that the WNA should be compared to the WNAs of other utilities. In addition, unlike UGI Gas, PGW is a cash flow utility. Finally, I would note that Columbia's WNA is still a pilot program.
Consideration 14	Please explain how the WNA will support improvements in utility reliability.
	Initial UGI GAS: UGI Gas' cost of service is inclusive of investments and costs to continue to enhance the safety and reliability of its system. The proposed WNA will help minimize the volatility of the recovery of these costs.
	Initial OCA: The WNA does not provide an incentive to increase the safety and reliability of the UGI Gas System.

> Rebuttal UGI Gas: As stated in my direct testimony, the proposed WNA will help minimize the volatility of the recovery of UGI Gas's cost of service, inclusive of investments and costs to continue enhancing the safety and reliability of its system. The stabilization of cash flows allows a utility to focus more acutely on operational items under its direct control, as Chairman Gladys Brown Dutrieuille determined upon review of Columbia's WNA, when she stated, "This decoupling of uncontrollable weather from revenues stabilizes Columbia's cashflow, and in turn, allows Columbia to more acutely focus on operational items within its control; namely infrastructure upgrades and repairs."
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> Surrebuttal OCA: The WNA will reduce the volatility in cash flows for UGI Gas. As previously explained, if customers are interested in reducing the volatility of their gas utility bill, they already have this option through budget billing.

Q. PLEASE SUMMARIZE YOUR POSITION ON WHETHER THE WNA SHOULD BE APPROVED.

A. The WNA should not be approved because it embodies a take-or-pay pricing policy, inappropriately adjusts rates without considering other changes in total revenues and costs, UGI Gas has not demonstrated that its current system of rates and charges results in inadequate revenue stability, and does not decrease the frequency of base rate case filings by UGI Gas. If the Commission elects to approve a WNA for UGI Gas, a 3% dead band should be included in the WNA similar to the dead band currently utilized in Columbia's pilot WNA.

Q. IN ADDITION TO BEING ADDRESSED BY MS. HEPPENSTALL AND MS. EPLER, MR. TAYLOR ALSO ADDRESSES YOUR RESIDENTIAL CUSTOMER CHARGE PROPOSAL.[63] DOES MR. TAYLOR PRESENT

[63] Rebuttal Testimony of John D. Taylor, UGI Statement No. 11-R, pp. 29-34.

ANY NEW REBUTTAL TESTIMONY ON THIS ISSUE TO WHICH YOU WOULD LIKE TO RESPOND?

A. No. Mr. Taylor's rebuttal testimony is similar to that of Ms. Heppenstall and Ms. Epler on this issue and I have already responded to Ms. Heppenstall's Ms. Epler's rebuttal testimony.

VI. <u>OSBA</u>

WITNESS: Robert D. Knecht

Q. MR. BROWN INDICATES THAT OSBA WITNESS MR. KNECHT PROPOSED A RATE INCREASE FOR THE RATE IS CUSTOMER GROUP.[64] DID YOUR PROPOSED REVENUE ALLOCATION ALSO INCLUDE A RATE INCREASE FOR RATE IS?

A. Yes.[65]

Q. DID MR. BROWN AGREE WITH THE INCREASE PROPOSED BY MR. KNECHT FOR RATE IS?

A. No. Mr. Brown claims that customers paying Rate IS are competitively situated customers with negotiated rates. He claims that these customers have options that could either allow them to bypass the UGI Gas system or they may move their operations outside the Company's service territory. He further claims that the Company's ability to increase the rates of Rate IS customers is limited.[66]

Q. WHAT IS YOUR RESPONSE TO MR. BROWN'S CLAIM CONCERNING INCREASING THE RATES FOR CUSTOMERS SERVED UNDER RATE IS?

[64] Rebuttal Testimony of Christopher R. Brown, UGI Statement No. 1-R, p. 33.

[65] Direct Testimony of Jerome D. Mierzwa, OCA Statement No. 4, p. 33.

[66] Rebuttal Testimony of Christopher R. Brown, UGI Statement No. 1-R, p. 34.

A. Mr. Brown's claims imply that it is unreasonable to ever propose an increase for Rate IS customers with competitive options. A comparison of revenues at present rates in the Company's two prior base rate cases and in the current proceeding is presented below. This comparison reveals that it is unreasonable to contend that UGI Gas cannot increase the revenues generated by Rate IS customers in the future:

Revenues at Present Rates

	Docket No. R-2018-3006814	Docket No. R-2019-3015162	Docket No. R-2021-3030218
Rate IS	$15,007,007	$23,442,353	$24,012,357

Q. DO YOU HAVE ANY INITIAL COMMENTS CONCERNING MR. KNECHT'S REBUTTAL TESTIMONY?

A. Yes. Several of the statements with which I do not agree that are included in Mr. Knecht's rebuttal testimony were included in his direct testimony. I have previously responded to these statements in my rebuttal testimony and, therefore, it is unnecessary to again respond to those statements.

Q. IN YOUR DIRECT TESTIMONY, YOU PRESENTED WHAT MR. KNECHT HAS CHARACTERIZED AS FOUR "TECHNICAL CHANGES" TO THE COMPANY'S COST OF SERVICE STUDY.[67] DOES MR. KNECHT ACCEPT THOSE CHANGES?

A. In my direct testimony I presented "technical changes" to the allocation of MGP remediation costs, forfeited discounts, reconnection fees, and the sub-finalization of costs in Account 874. Mr. Knecht agreed with all of these technical changes except the allocation of reconnection fees.[68]

[67] Direct Testimony of Robert D. Knecht, OSBA Statement No. 1-R, p. 3.
[68] *Id.*

Q. WHAT DOES MR. KNECHT RECOMMEND CONCERNING THE ALLOCATION OF RECONNECTION FEES?

A. Mr. Knecht believes reconnection fees and reconnection costs should be allocated on the same basis. He proposes to allocate reconnections fees based on an aggregate O&M allocation.[69]

Q. WHAT IS YOUR RESPONSE TO MR. KNECHT'S RECOMMENDATION?

A. Mr. Knecht has not demonstrated that an aggregate O&M allocation for reconnection fees is reasonable. In addition, as previously indicated, I would note that the Company has accepted my technical change to the allocation of reconnection fees.

Q. WHAT DOES MR. KNECHT CONCLUDE CONCERNING YOUR PROPOSED REVENUE ALLOCATION?

A. Mr. Knecht finds that my proposed revenue allocation is directly consistent with the results of my P&A cost-of-service study. However, he contends that my revenue allocation does not move the Rate R/RT class sufficiently toward the cost of service indicated by my P&A study. More specifically, as presented in Table RDK-R1, my revenue allocation moves the Rate R/RT class from a revenue-cost rate of 91.9% to 95.3%, or nearly 50% toward the cost of service indicated by my P&A study. As shown in Table RDK-R2, Mr. Knecht subsequently proposes a revenue allocation which moves the revenue-cost ratio of Rate R/RT customers to 97.7% of the cost of service indicated by my P&A study.[70]

Q. WHAT IS YOUR RESPONSE TO MR. KNECHT'S ALTERNATIVE REVENUE ALLOCATION?

[69] *Id.*

[70] *Id.*, pp. 4-6.

A. As shown in Table RDK-R1, with the exception of Rate XD, my proposed revenue allocation reflects significant movement toward the cost-of-service rates indicated by my P&A study for the Rate R/RT, Rate N/NT and Rate DS customer classes for which current revenues differ most significantly from the indicated cost of service. I have not proposed a revenue decrease for Rate XD-firm even though the revenues from this class exceed the indicated cost of service because I don't believe it to be appropriate for any customer class to receive a rate decrease when overall, rates are increasing. The revenues at present rates for Rate LFD customers are essentially equal to the indicated cost of service under my proposed revenue allocation, and would remain cost based under proposed rates. For Rate IS/XD-I whose current rates were slightly in excess of the indicated cost of service, I have proposed cost-based rates. I believe that this proposed revenue allocation is reasonable in that it provides for gradualism and significant movement toward cost-based rates.

VI. CONCLUSION

Q. IN LIGHT OF THE POSITIONS OF THE PARTIES IN THIS PROCEEDING, HAVE YOU MODIFIED YOUR P&A COST OF SERVICE STUDY AND REVENUE ALLOCATION PRESENTED IN YOUR DIRECT TESTIMONY?

A. Yes. The cost-of-service study initially presented in my direct testimony allocated distribution mains costs based on the P&A method. Nothing presented in the rebuttal testimony of the other parties has changed my finding that the P&A method is consistent with cost-of-service principles. My initial cost-of-service study reflected three additional "technical changes" to the Company's A&E cost-of-service study. These technical changes related to the allocation of MGP remediation costs, forfeited discounts, and reconnection fees. As explained previously in this surrebuttal testimony, my position has not changed on these cost allocations. The only cost of service study change proposed by a party in this proceeding which I have not opposed is Mr. Knecht's proposed change in the calculation of the design day demands for the Rate R/RT and Rate N/NT classes. I have revised my initial study to reflect this change and modified my proposed revenue allocation to reflect the results of my revised study. Schedule JDM-1 Revised presents the results of my revised study at present rates. I have also revised Tables 5, 7, and 8 from my direct testimony to reflect the results of my revised study, and have revised the revenue allocation for Rates R/RT and N/NT. These revised tables are presented below. In developing my revised revenue allocation, I have attempted to maintain the same movement towards cost based rates for Rates R/RT and N/NT that was initially reflected in my direct testimony.

Table 1. Revised - Combined Class Cost of Service and Rate of Return Present Rates

	Company			**OCA Study**		
	Cost of Service	**Rate of Return**		**Cost of Service**	**Rate of Return**	
Class		**Percent**	**Unitized**		**Percent**	**Unitized**
Residential (R)	$471,011,760	4.33%	0.70	$464,929,702	4.54%	0.74
Non-Residential (N)	$146,888,226	7.28%	1.18	$133,497,262	8.75%	1.42
Delivery Service (DS)	$32,808,421	8.61%	1.40	$32,985,305	8.52%	1.39
Large Firm Delivery Service (LFD)	$41,387,804	9.44%	1.54	$50,480,155	6.36%	1.04
Extended Large Firm Delivery Service (XD)	$28,012,485	14.01%	2.28	$30,405,440	12.32%	2.01
Interruptible (IT)	$17,906,171	13.46%	2.19	$25,712.852	7.11%	1.16
Overall	**$738,014,867**	**6.14%**	**1.00**	**$738,003,977**	**6.14%**	**1.00**

Table 2. Revised - OCA Proposed Cost of Service Study Revenue Distribution

Class	**Present Rates**	**Proposed Rates**	**Increase**	**Percent**
Residential (R)	$377,368,713	$440,150,632	$62,781,919	16.6%

Non-Residential (N)	$138,825,398	$149,304,131	$10,478,733	7.5%
Delivery Service (DS)	$33,778,394	$35,906,433	$2,128,040	6.3%
Large Firm Delivery Service (LFD)	$44,861,623	$50,514,565	$5,652,942	12.6%
Extended Large Firm Delivery Service (XD)	$36,697,802	$36,697,801	$0	0.0%
Interruptible (IT)	$24,012,357	$25,712,852	$1,700,496	7.1%
Total	**$655,544,286**	**$738,286,415**	**$82,742,129**	**12.6%**

Table 3. Revised - Unitized Rates of Return

Class	**Present Rates**	**Proposed Rates**
Residential (R)	0.74	0.87
Non-Residential (N)	1.42	1.22
Delivery Service (DS)	1.39	1.19
Large Firm Delivery Service (LFD)	1.04	1.00
Extended Large Firm Delivery Service (XD)	2.01	1.51
Interruptible (IT)	1.16	1.00
Total	**1.00**	**1.00**

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

OCA Statement 3SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	))	
	)	
v.	)	Docket No. R-2021-3030218
	)	
UGI UTILITIES, INC. – GAS DIVISION	))	

SCHEDULE ACCOMPANYING THE

SURREBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

May 27, 2022

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

UGI UTILITIES, INC. - GAS DIVISION

DEVELOPMENT OF RATE OF RETURN BY SERVICE CLASSIFICATION
UNDER PRESENT RATES

Item	Cost of Service	Rate R	Rate N	Rate DS	Rate LFD	Rate XD-Firm	Interruptible
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1. Revenues From Tariff Sales and Transportation	$ 655,544,286	$ 377,368,713	$ 138,825,398	$ 33,778,394	$ 44,861,623	$ 36,697,802	$ 24,012,357
2. Other Revenues	10,286,610	6,250,570	2,548,796	423,202	529,571	310,372	224,099
3. Total Operating Revenues	665,830,896	383,619,283	141,374,194	34,201,596	45,391,194	37,008,174	24,236,456
4. Less: Operating Expenses	431,314,923	284,415,344	69,777,650	18,753,179	26,232,788	19,183,422	12,952,540
5. Return and Income Taxes	234,515,973	99,203,939	71,596,544	15,448,417	19,158,406	17,824,751	11,283,916
6. Less: Interest Expense	56,726,000	33,292,489	11,912,460	2,643,432	4,464,336	2,076,172	2,337,111
7. Taxable Income	177,789,973	65,911,450	59,684,084	12,804,985	14,694,070	15,748,579	8,946,805
8. Less: Income Taxes	39,835,701	14,767,094	13,372,845	2,868,170	3,290,429	3,529,443	2,003,736
9. Net Return (Ln 5 - Ln 8)	194,680,272	84,436,845	58,223,699	12,580,247	15,867,977	14,295,308	9,280,180
10. Original Cost Measure of Value (Factor 15.)	3,169,006,223	1,859,876,690	665,497,918	147,663,458	249,382,109	116,011,565	130,574,483
11. Rate of Return, Percent	6.14%	4.54%	8.75%	8.52%	6.36%	12.32%	7.11%
12. Relative Rate of Return	1.00	0.74	1.42	1.39	1.04	2.01	1.16

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 3SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2022
*329516

Signature: Jerome D. Mierzwa
Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044-3575

OCA Statement 4SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2021-3030218
UGI Utilities – Gas Division	:	

Surrebuttal Testimony of
Roger D. Colton

On Behalf of:
Office of Consumer Advocate
Statement 4SR

May 27, 2022

Table of Contents

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED DIRECT AND REBUTTAL TESTIMONY FOR THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING? IN WHAT POSITION?

A. Yes.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY.

A. The purpose of my Direct Testimony is to respond to the Rebuttal Testimony of the following witnesses:

- CAUSE-PA rebuttal witness Harry Geller;
- I&E rebuttal witness Zachari Walker;
- UGI Gas rebuttal witness Chris Brown;
- UGI Gas rebuttal witness Sherry Epler;
- UGI Gas rebuttal witness Constance Heppinstall;
- UGI Gas rebuttal witness John Taylor; and
- UGI Gas rebuttal witness Daniel Adamo.

PART 1. Response to CAUSE-PA Witness Harry Geller.

Q. PLEASE RESPOND TO MR. GELLER'S REBUTTAL TESTIMONY REGARDING YOUR PROPOSED SCREENING OF CUSTOMERS CONVERTED TO NATURAL GAS FOR CAP ELIGIBILITY.

A. CAUSE-PA witness Harry Geller states that he supports my recommendation to screen gas conversion customers for CAP in order to help ensure that UGI Utilities – Gas Division (UGI or the Company) customers can afford service and reduce uncollectible costs passed on to other customers (CAUSE-PA St. 1-R at 2-3). As I noted in my Direct Testimony, while UGI has converted nearly 30,000 customers to natural gas, it has identified only 354 of those customers (1.2%) as Confirmed Low-Income customers.

Mr. Geller states, however, that screening these customers for low-income status "will not address the low CAP participation numbers for UGI's existing low-income customers. . ." (CAUSE-PA St. 1-R at 2). I agree with Mr. Geller's observation.

My remedy for UGI's failure to confirm the low-income status of its customers, and to enroll those Confirmed Low-Income customers in its Customer Assistance Program (CAP), is to establish measurable outcome objectives. As I state in my Direct Testimony, and will discuss further below in this Surrebuttal Testimony, establishing measurable outcome objectives are based on the need to define clear agency missions, set results-oriented goals, measure progress toward achievement of those goals, and use performance information to help make decisions and strengthen accountability. I share Mr. Geller's concerns about the extent to which low-income customers are identified by UGI Gas and enrolled in CAP. And I agree that his recommended remedy is reasonable and urge its adoption. The remedy I propose is necessary even if Mr. Geller's recommendations are approved.

The purpose of screening customers converted to natural gas, however, is not simply to expand the population of Confirmed Low-Income customers or the CAP enrollment. As I explain in my Direct Testimony, without screening natural gas conversions in this fashion, and extending LIURP to those customers, the conversion of customers to natural gas will impose unnecessary costs on remaining ratepayers. While natural gas conversions likely generate both environmental and affordability benefits to the customers converted, UGI Gas should undertake those reasonable steps I propose to mitigate the adverse cost consequences to other ratepayers.

PART 2. Response to I&E Witness Zachari Walker .

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of I&E witness Zachari Walker. Mr. Walker opposes my recommendation to provide an increase of $524,450 to treat low-income customers who are converted from non-gas heating fuels to natural gas. Mr. Walker argues that UGI has not exhausted its LIURP spending in recent years and thus there is no reason to expand that budget in this proceeding. (I&E St. 1-R at 3).

Mr. Walker does not acknowledge three things which render his conclusion not well-grounded. First, Mr. Walker does not acknowledge the spending dynamics which underlie the discovery request he cites. It is true that UGI North did not spend its LIURP budget in 2019. However, the amount of under-spending was only $37,547, or 3.7% of the projected spending. (BCS 2019 annual Report on Universal Service Programs and

Collections Performance, at 46) (projected spending of $1,015,495 with actual spending of $977,948). The substantial UGI Gas under-spending in 2019 was with UGI South (projected 2019 spending of $1,816,431 and actual spending of $1,162,713). (Id.) UGI South projected that it would use that 2019 under-spending in 2020. (Id.) However, as we all know, the world shutdown in 2020 due to COVID-19. Utilities across the nation had difficulties in spending all of their energy efficiency budgets during the economic shutdown during the COVIDI-19 pandemic. Not spending one's budget during the COVID-19 years of 2019 and 2020 is no reason not to provide the budget that is needed today.

Second, Mr. Walker does not acknowledge that my recommendation is not merely to increase the budget, but to create a mechanism identifying the increased need. I do not propose to increase the LIURP budget and then expect UGI to create the demand for that budget. My recommendation is to provide the budget necessary to meet the demand that will exist given the continuing UGI efforts to convert customers, including low-income customers, from non-natural gas heating fuels to natural gas service.

Finally, Mr. Walker does not acknowledge that his recommendation to deny my proposed increase in the LIURP budget for a specific purpose (i.e., to serve low-income households converted to natural gas from non-natural gas heating fuels) will, unto itself, impose a substantial cost on other ratepayers. Indeed, as I noted, and Mr. Walker did not acknowledge, expanding the LIURP budget to treat these "new" CAP participants will result in a dollar-for-dollar decrease in CAP spending for every dollar of bill reduction achieved through LIURP. In addition, the LIURP investments will reduce costs to other ratepayers through the reduction of arrears subject to forgiveness. Each of these cost reductions will, on a dollar-for-dollar basis, be a reduction in rates to remaining ratepayers through a reduction in costs passed through the UGI Gas Universal Service Rider.

<u>PART 3. Response to UGI Witness Chris Brown</u>.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I address the Rebuttal Testimony of Chris Brown, UGI St. No. 1-R. While Mr. Brown states that he will respond to my Direct Testimony, at no point does his testimony directly cite my testimony and provide a response.

Mr. Brown does assert in generic terms that "UGI Gas has exceptional customer satisfaction performance. . ." (UGI St. No. 1-R at 10). I respond further to UGI Gas testimony with respect to "customer satisfaction" in my response to the Rebuttal Testimony of Daniel Adamo below.

<u>PART 4. Response to UGI Rebuttal Witness Sherry Epler</u>.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of Sherry Epler. Ms. Epler, UGI St. No. 8-R, references the Rebuttal Testimony of Daniel Adamo for the proposition that "low-income customers are, on average, higher use customers." (UGI St. No. 8-R at 19). I will respond to that argument in my response to Mr. Adamo below.

Ms. Epler further states, however, that "an increase in [the] customer charge. . .serves to reduce the burden on low-income customers." (UGI St. No. 8-R at 19). In making that statement, however, Ms. Epler ignores the unrebutted information I provide documenting that: (1) the increased customer charge will increase rates to at least 86% of UGI's estimated low-income customers who are not protected by UGI's CAP (OCA St. 4 at 8); (2) the increased customer charge, standing alone, will remove 95.4% of the total value of federal fuel assistance being delivered to UGI Gas' low-income customers (OCA St. 4 at 10); (3) the UGI Gas proposed increase in its fixed monthly customer charge will increase the payment difficulties which low-income customers currently face (OCA St. 4 at 11); and (4) the increased UGI Gas customer charge will make it more difficult for low-income customers to control their exposure to unaffordable bills through the implementation of energy efficiency or usage conservation measures. (OCA St. 4 at 11). Ms. Epler errs when she argues, without evidentiary support, that the increase in the customer charge will "reduce the burden on low-income customers." (UGI St. 8-R, at 19).

PART 5. Response to UGI Rebuttal Witness Constance Heppenstall.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I briefly note that while UGI Gas Rebuttal Witness Constance Heppenstall asserts that she responds to my Direct Testimony (UGI St. No. 10-R at 1, 10), no part of her testimony takes issue with the information and data I present in my Direct Testimony. Accordingly, I provide no further response to Ms. Heppenstall.

<u>PART 6. Response to UGI Gas Rebuttal Witness John Taylor</u>.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of John Taylor, UGI St. No. 11-R. Mr. Taylor responds to my Direct Testimony regarding the UGI Gas proposed Weather Normalization Adjustment (WNA). He argues that (1) the WNA does not disproportionately adversely affect low-income customers (UGI St. No. 11-R at 8 - 9); (2) that budget billing does not provide a better alternative mechanism through which to stabilize their monthly payments (UGI St. No. 11-R at 9 – 10, 24); and (3) that the Company's proposed increased customer charge will decrease annual bills to CAP customers. In addition, Mr. Taylor asserts that UGI Gas provides adequate consumer education to customers regarding the proposed WNA. (UGI St. No. 11-R at 27 – 28).

Q. DOES THE WNA DISPROPORTIONATELY ADVERSELY AFFECT LOW-INCOME CUSTOMERS?

A. Yes. I demonstrate that low-income customers will be disproportionately affected by the WNA. While Mr. Taylor cites a conclusory statement that I make regarding the impacts of the WNA (made in response to a question "what do you conclude?"), he does not address the ways in which low-income customers are adversely affected.

- More low-income customers are in arrears during the cold weather months. The WNA will increase bills during some winter months. As I demonstrate, the fact that "on average," over multiple years, bills will be somewhat the same is irrelevant from a low-income perspective. It is the month-to-month variation.

- Not only are more low-income customers in arrears during the cold weather months, but they are ***<u>deeper</u>*** in arrears. When those arrears become due, total bill payments (arrears plus bills for current service) become a higher percentage of income and thus less payable. Again, the fact that on average, over multiple years, bills will be somewhat the same does not address the adverse impacts on low-income customers by taking bills that are likely already unaffordable and making them more so.

- By increasing the winter bills (in some years), low-income customers reach the spring months with a higher outstanding balance and are, as a result, more likely to be disconnected.

- When low-income accounts are disconnected for nonpayment, they will be disconnected with a higher outstanding balance at the time of disconnection. Accordingly, it will be more difficult to have service restored.

Low-income customers are not protected by UGI's PIP. As I discuss in my Direct Testimony, UGI identifies a small portion of customers as Confirmed Low-Income customers and, even then, enrolls a small portion of its Confirmed Low-Income customer base in its PIP. These observations are made consistently throughout my Direct Testimony. To cite my conclusion without addressing the underlying data and discussion presented throughout my testimony does not serve to "rebut" the data presented.

Q. DOES BUDGET BILLING PROVIDE A BETTER ALTERNATIVE TO STABILIZE MONTHLY PAYMENTS THAN THE WNA?

A. Yes. The question originally presented by UGI Gas was not whether rates would be more stable on a year-to-year basis. Remember what Taylor first asserted in his Direct Testimony. He asserted as the advantage of the WNA that "certain customers enrolled in the Customer Assistance Program (CAP) who pay an 'average bill' amount will see lower bill variability for distribution costs ***during colder than average periods***. . ." (UGI Gas St. No. 11 at 16) (emphasis added). He further asserts that "customers receive greater stability in the non-gas portion of their utility bills, a benefit ***during the winter*** *months* when gas prices tend to be at their highest, and a particular benefit for low-income customers with high bills *during the lengthy heating seasons* in UGI Gas's service areas." (Id. at 22) (emphasis added).

What drives customer inability-to-pay is not year-to-year variation in bills, but rather is month-to-month variation. (See e.g., OCA St. 4, Figure 2, at 34). The WNA has no impact on providing bill stability to customers during the winter months (i.e., during "the heating season"). What customers need to stabilize their winter heating bills is budget billing. It is not the year-to-year volatility in bills, it is the monthly volatility.

Q. DOES THE PROPOSED INCREASE IN CUSTOMER CHARGE DECREASE ANNUAL BILLS TO LOW-INCOME CUSTOMERS?

A. No. Taylor does not address the impact of the proposed WNA on low-income customers generally. Instead, he asserts that the WNA will reduce annual bills to *CAP* customers. (UGI St. No 11-R at 34) (emphasis added). What Taylor does not acknowledge is that the population of "CAP participants" is not representative of, let alone synonymous with, the low-income population in general. The UGI CAP program is largely percentage of income based. What that means is that customers whose usage is sufficiently low that the bill is lower than the percentage of income will not participate in the program. While half (51%) of the UGI CAP participants are on the "average bill" CAP program component, that means that half of the CAP participant population does participate in the percentage of income program. With half of the CAP population being low-income customers with bills sufficiently high to be higher than the maximum bill burdens provided through PIPP, the overall usage of the total CAP participant population will be substantially higher than the overall low-income customer base. Even if Mr. Taylor is correct in that CAP participants will have an average reduction in their bills of somewhat less than $1.00 per month ($11.63 per year / 12 months), those participants are not representative of the low-income customer base. Mr. Taylor argues that he presents a similar comparison for "low-income" customers. He does not acknowledge the low percentage of low-income customers that the Company has identified as confirmed low-income customers.

Q. WHAT DO YOU KNOW ABOUT THE RELATIONSHIP BETWEEN NATURAL GAS USAGE AND LOW-INCOME STATUS?

A. Every federal agency that has examined natural gas usage and income has found that as income increases, natural gas consumption increases as well. The fact that any one of these federal agencies reaches this conclusion is perhaps not the most significant observation to draw from this data. The more significant conclusion to draw is the fact that ***every single one*** of the federal agencies charged with studying such relationships has found a relationship to exist between income and natural gas consumption. Low-income customers use less gas, period.

Consider, first, the U.S. Department of Energy's Energy Information Administration (DOE/EIA) data generated through its Residential Energy Consumption Survey (RECS). The most recent (2015) DOE/EIA data reports that there is an association between energy use, natural gas use, and income. For both the United States as a whole, and for the Northeast Census Region (of which Pennsylvania is a part), while energy usage and natural gas usage is less efficient at lower income levels, total usage increases as incomes increase. In the Northeast Region, for example, while households with income less than $20,000 use 501 CCF of natural gas per year (on average), households with income at $80,000 to $99,999 use 779 CCF, and households with income at $120,000 to $140,000 use 972 CCF.

Table 1. U.S. and Northeast Total Energy Consumption and Natural Gas Consumption by Income (U.S. Department of Energy/Energy Information Administration)

Annual Income	U.S. Site Energy Consumption		U.S. Energy Expenditures		Northeast Average Site Natural Gas Consumption (of HHs Using Nat Gas)	
	Per Household (million Btu)	Per Square Foot (thousand Btu)	Per Household (dollars)	Per Square Foot (dollars	Per Household (million Btu)	Per Household (CCF)
Less than $20,000	67.2	46.6	$1,320	$0.91	52.0	501
$20,000 - $39,999	84.7	44.5	$1,571	$0.82	63.5	616
$40,000 - $59,999	88.7	40.6	$1,675	$0.77	64.8	630
$60,000 - $79,999	99.3	40.8	$1,872	$0.77	65.9	642
$80,000 - $99,999	105.4	41.1	$1,996	$0.78	80.2	779
$100,000 - $119,999	113.9	34.9	$2,205	$0.68	99.7	972
$120,000 - $139,999	124.8	39.6	$2,294	$0.73	85.7	833
$140,000 or more	143.8	38.8	$2,418	$0.65	80.0	782

This lower total consumption for low-income customers occurs despite the fact that natural gas usage by low-income consumers may be less efficient than gas consumption by higher income consumers. The lower efficiency occurs because low-income households tend to live in less energy efficient homes. They tend to use less efficient energy consuming systems (e.g., space heating systems, hot water systems).[1] However, despite this inefficiency, low-income homes are sufficiently smaller --often multi-family

[1] The extent to which, if at all, ratepayers should provide subsidies for energy efficiency improvements is not at issue in this proceeding. I do not address that question.

rental apartments rather than single-family detached homes-- that the *total* consumption of low-income households is lower than residential customers as a whole.

It is not merely DOE/EIA data which reports that natural gas consumption increases as income increases. The U.S. Bureau of Labor Statistics releases its Consumer Expenditures Survey (CEX) on an annual basis. The CEX tracks natural gas expenditures by income level. In the Northeast, natural gas expenditures are somewhat less than three times higher with an income of $200,000 or more compared to expenditures at an income of less than $15,000; they are more than two times higher at an income of $100,000 to $149,999 than they are at an income of less than $15,000. The same relationship exists for natural gas expenditures nationwide as exists for natural gas expenditures in the Northeast.

Table 2. Mean Expenditures on Natural Gas by Income before Taxes
(U.S. and Northeast) (U.S. Department of Labor Statistics)
(shading simply to improve readability)

	Less than $15,000	$15,000 to $29,999	$30,000 to $39,999	$40,000 to $49,999	$50,000 to $69,999	$70,000 to $99,999	$100,000 to $149,999	$150,000 to $199,999	$200,000 or more
U.S. (2020)	$251	$313	$339	$347	$389	$430	$496	$569	$732
Northeast (2019 – 2020)	355	468	543	551	574	640	715	798	988

Finally, the U.S. Department of Health and Human Services (HHS), which is the federal agency administering the Low-Income Home Energy Assistance Program (LIHEAP), publishes a periodic “Home Energy Notebook.” The LIHEAP agency’s Home Energy Notebook includes data both on home energy expenditures by heating fuel and on home energy consumption by heating fuel. The most recent HHS Home Energy Notebook compared natural gas expenditures and consumption for “all households,” “non-low-income households” and “low-income households” (in addition to splitting LIHEAP recipients out separately). Like the Department of Energy and the Department of Labor Statistics, the federal LIHEAP office finds that low-income households use noticeably less natural gas for space heating than do non-low-income households. According to the LIHEAP report, low-income households annually use 18 MMBtus less natural gas for space heating, and spend nearly $500 less for natural gas space heating than do non-low-income households.

Table 3. Annual Average Natural Gas Heating Expenditures and
Annual Average Natural Gas Heating Usage
(Per Household) (Northeast Region) (LIHEAP Home Energy Book)

	Usage (MMBtus)	Expenditures
All households	121.8	$2,530
Non-low-income households	128.2	$2,710
Low-income households	110.9	$2,225

Q. WHAT DO YOU CONCLUDE?

A. Every federal agency that has an institutional mission of considering such data, and that has examined the question, has empirically found that income and natural gas usage are associated with each other. Mr. Taylor’s use of a non-representative sample of low-income customers, which is non-representative in a way that would inflate usage figures, cannot be found to contradict these findings.

Q. WHAT FACTORS DRIVE THIS RESULT?

A. The factors that drive this result in the UGI Gas service territory are the same factors that the DOE/EIA Residential Energy Consumption Survey has found to drive the result.

While gas consumption may be less efficient at lower incomes than the gas consumption at higher incomes on a per-square foot of housing basis, low-income households tend to live in much smaller housing units. As a result, even while the gas usage may be less efficient on a per square foot basis, low-income households live in homes that have sufficiently fewer square feet of housing space that the total gas consumption is nonetheless lower for lower income households.

Q. DOES UGI GAS PROPOSE AN ADEQUATE CUSTOMER INFORMATION AND EDUCATION PROGRAM FOR THE WNA?

A. No. First, it is important to remember that UGI does not have, and did not present, a consumer education program. Mr. Taylor could only say that "[t]he Company is *working to develop* a communication plan designed to educate customers about the WNA mechanism." (UGI St. No. 11-R at 27) (emphasis added). The only "customer education" efforts that UGI Gas proposes, other than "notice" required by regulation, include a bill insert, an article in the Company's "customer newsletter," and posting to the Company's website. (UGI St. No. 11-R at 27). It also plans to "train" its customer service representatives. (UGI St. No. 11-R at 28).

Taylor identifies no culturally appropriate outreach. As the National Regulatory Research Institute (NRRI), the research arm of the National Association of Regulatory Utility Commissioners (NARUC), has reported, consumer outreach and education needs to differ based on age, ethnicity, and income. Some customers turn to neighbors and friends, while others turn to the utility. Some customers depend on word of mouth, while others rely on contacts from the utility. Some customers turn to nonprofit community organizations, while others rely on the media. What a consumer outreach and education program is *not* is a program that relies on bill inserts, an article in the Company newsletter, and internal training to internal staff.

PART 7. Response to UGI Gas Rebuttal Witness Daniel Adamo.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the Rebuttal Testimony of Daniel Adamo, UGI St. No. 12-R. Mr. Adamo addresses my Direct Testimony regarding COVID-19 relief, customer satisfaction, the residential customer charge, natural gas conversions, and the establishment of measurable Outcome Objectives for low-income customers.

A. Continuing COVID Relief.

Q. PLEASE EXPLAIN WHAT MR. ADAMO STATES IN REBUTTAL WITH RESPECT TO UGI's COVID-19 RESPONSE?

A. Mr. Adamo outlined a series of steps undertaken by UGI Gas to respond to the COVID-19 pandemic, and the economic crisis associated with that health crisis. According to Mr. Adamo, the Company ceased service terminations on March 13, 2020; stopped removing customers from its Customer Assistance Program ("CAP") for failure to recertify on March 18, 2020; and voluntarily began waiving all late payment charges on March 24, 2020. (UGI St. No. 12-R at 4). Moreover, Mr. Adamo stated that since its last rate case, the Company increased its Operation Share donations by $500,000 per year beginning FY19; expanded eligibility under its Operation Share grant program to 250% of the federal poverty limit ("FPL"); and increased the maximum grant size from $400 to $600. (Id.) Mr. Adamo cited UGI Gas' COVID-19 Emergency Relief Program ("ERP"), which provided benefits including billing relief and/or payment relief for customers who needed temporary relief measures during the pendency of the COVID-19 pandemic, as well as for a limited period following the termination of the PUC Emergency Order period. (Id.) I don't deny any of those actions, or the benefits provided to UGI Gas customers as a result of those actions.

Q. WHERE DO YOU DIFFER FROM MR. ADAMO'S REBUTTAL TESTIMONY?

A. Where Mr. Adamo errs is when he asserts that UGI Gas no longer needs to undertake any further COVID-19 related relief. Mr. Adamo states that continued UGI action "need not be continued in light of the transition back to pre-COVID-19 employment rates and the increase in other state and federal programs. . ." (UGI St. No. 12-R at 7). Moreover, Mr. Adamo errs in concluding that the fact that only 16% of the CAP customers UGI Gas sought to recertify in October 2021 recertified in fact, and only 17% of those UGI Gas sought to recertify did so in January 2022, is evidence of the fact that those customers not recertifying were no longer in need. He offers no evidence that a failure to recertify is evidence of, let alone conclusive evidence of, the fact that customers were no longer in need.

Mr. Adamo's testimony is not consistent with the data UGI Gas provided in response to discovery. According to UGI Gas, while there was a spike in the number of customers who exited CAP in July/August 2021 (n=1,921), which was to expected given that those were the first months in which UGI Gas required a recertification since the inception of

COVID, only 178 more customers failed to recertify during the months of September through November 2021. Only in December 2021/January 2022, was there another spike in the number of customers who failed to recertify (2,262), the months where it is most likely that CAP participants would have credits on their bill attributable to the receipt of LIHEAP. (OCA-II-16). One additional fact that Mr. Adamo does *not* provide is the number of those customers who exited CAP due to a failure to recertify who subsequently re-entered CAP by providing the required recertification information.

All in all, from July 2021 through January 2022, one piece of data that Mr. Adamo did not provide was the fact that more people were removed from CAP due to the fact that they had moved than were removed from CAP due to a failure to recertify. (OCA-II-16). Moreover, Mr. Adamo did not disclose in his testimony that only 456 CAP participants were removed for being over-income. (Id.) That figure is a far better indicator of who might have entered the program during the COVID pandemic but no longer needed CAP. Indeed, UGI Gas data demonstrates that while 358 CAP participants were removed for being over-income in the first six months of 2021, only 419 were removed for being over-income in the last six months of 2021. (Id.). There is no indication at all that CAP exits experienced any substantial fly-ups attributable to people who entered CAP while they were in economic distress in the COVID months of 2020 and 2021 and then left CAP when that distress no longer existed.

Finally, while Mr. Adamo asserts in summary fashion that there has been a "transition back to pre-COVID-19 employment rates," he provides no data to support that conclusion, particularly for the lower-income customers who were most affected by the loss of jobs and/or the cutback in hours. Particularly in the low wage job sector, the loss of jobs attributable to COVID-19 has been found to involve a permanent loss of jobs. Moreover, while Mr. Adamo cites the availability "existing federal programs, such as Emergency Rental Assistance Program ("ERAP") and Pennsylvania Homeowner Assistance Fund ("PAHAF"), and LIHEAP" (UGI St. No. 12-R at 33), he does not report that the first two of those programs are *temporary* emergency crisis programs, and that they primarily provided housing assistance. Even the spike in LIHEAP funding that occurred in 2021 is not now expected to be repeated (and, more recently, proposals have been made to add water assistance to LIHEAP without a corresponding increase in overall funding).

What Mr. Adamo does not rebut is the continuing economic crisis facing lower-income households in Pennsylvania. Indeed, he does not even to respond to the facts that I documented in my Direct Testimony that the difficulties that lower-income are having in paying normal household expenses in March/April 2022 are nearly as deep as the difficulties that were being experienced at the height of the health crisis in 2020 and 2021.

My recommendations did not involve UGI Gas continuing *every* COVID-19 response that it undertook for its payment challenged customers. But to argue now that the economic crisis is over and that, in any event, sufficient funding is available elsewhere to address the ongoing economic crisis is simply contrary to fact.

B. Customer Satisfaction.

Q. PLEASE OUTLINE WHAT MR. ADAMO STATES IN REBUTTAL WITH RESPECT TO CUSTOMER SATISFACTION.

A. Mr. Adamo criticizes my Direct Testimony regarding customer satisfaction by asserting that, aside from the metrics that I discussed in my Direct Testimony, other metrics existed showing that customers are "very satisfied" with UGI Gas customer service. (UGI St. 12-R, at 8) The only two metrics he provides, however, are satisfaction with the ability of customers to reach the Company and satisfaction with the Company's automated telephone system. (UGI St. No. 12-R at 8).

Once customers have reached the Company, however, their satisfaction substantially declines, a fact that Mr. Adamo refuses to even acknowledge, let alone seek to remedy. Mr. Adamo argues, for example, that when he examines customer satisfaction with "call center courtesy" and the "knowledge" of the Company's call center staff, the "Company's performance remains at a very high level." (Id. at 9). He does not acknowledge that the "satisfaction" figures he cites includes a combination of customers who are only "somewhat satisfied" along with those who are "very" satisfied.

The problem with amalgamating all of this "customer satisfaction" data together is that UGI Gas is seeking to use the data to demonstrate *exemplary* performance. Exemplary performance requires something more than customers, having made contact with the Company, reporting that those contacts are with staff that are merely "somewhat courteous" and only "somewhat knowledgeable."

Moreover, Mr. Adamo cites external customer satisfaction surveys as evidence of the Company's exemplary performance. (UGI St. 12-R, at 9). These surveys, which are cited but not provided, should not stand in lieu of evidence that the PUC, itself, dictates that Pennsylvania utilities annually file. It is more relevant, and more appropriate, to rely on the information I reviewed from the BCS 2020 "Customer Service Performance Report."[2] I used this data because it is the data that the PUC has deemed appropriate as a basis upon which to review utility performance. Mr. Adamo's citation to external third party surveys, which have not been explained or provided, cannot stand in lieu of the PUC's own data which, as I documented in my Direct Testimony, show that:

- UGI Gas ranked next to last (ahead of only PGW) in customer satisfaction with the "*overall quality of service*" during a recent contact. Nearly one-in-five (18%) of customers reported being less than "very satisfied" during their recent contact.

- UGI Gas customers ranked the Company below the statewide average for customer satisfaction with respect to credit and collection calls. UGI Gas' ranking was higher than NFG, and tied with PGW, but otherwise lower than average.

- UGI ranked last among Pennsylvania natural gas utilities on *overall customer satisfaction* with the way a premise visit was handled. Even when considering those customers who were only "somewhat satisfied," UGI customers reported satisfaction with premise visits in only 87% of the cases.

OCA St. 4 at 48._The customer satisfaction of UGI Gas customers does not support an adder to the Company's equity return for exemplary management.

[2] Available at https://www.puc.pa.gov/filing-resources/reports/customer-service-performance-reports/ (last accessed April 8, 20220.

C. Residential Customer Charge.

Q. PLEASE RESPOND TO MR. ADAMO'S TESTIMONY REGARDING THE PROPOSED INCREASE IN THE UGI GAS RESIDENTIAL CUSTOMER CHARGE.

A. Mr. Adamo criticizes my Direct Testimony about the adverse impact that the Company's proposed increase in the residential customer charge will have on low-income customers. His testimony, however, relies almost exclusively on the Rebuttal Testimony of UGI Gas witness Heppenstall and Taylor.

Mr. Adamo relies on one statement that is simply inaccurate. He asserts that I "assumed that all 153,437 low-income customers on page 9, line 18 of his direct testimony received Federal Fuel assistance funding." (UGI St. No. 12-R at 44). I made no such assumption. I not only specifically provided the amount of LIHEAP I relied upon in my Direct Testimony (OCA St. 4 at 10, lines 1 – 2), but cited the UGI Gas data request from which that dollar amount was taken. The amount of LIHEAP funding, in other words, was not my number, but was the number provided by UGI Gas, itself.

Q. DOES MR. ADAMO ERRONEOUSLY ARGUE THAT LOW-INCOME USAGE IS LOWER THAN RESIDENTIAL USAGE AS A WHOLE?

A. Yes. Mr. Adamo relies on his Exhibit DVA-5R in support of his erroneous assertion that low-income usage is lower than the usage of residential customers as a whole. His Exhibit, however, carries with it the same shortcomings that Mr. Taylor's related argument carries. His definition of "low-income" is of Confirmed Low-Income customers. He makes no effort to demonstrate that the sample of customers comprised of Confirmed Low-Income customers is representative of the Company's low-income customer base as a whole. Indeed, for all of the reasons I discussed in response to Mr. Taylor's Rebuttal Testimony, using the population of Confirmed Low-Income customers is not a representative sample of low-income customers as a whole. The Confirmed Low-Income customer base will systematically consume more natural gas than will lower-income customers as a whole. What Mr. Adamo does, in other words, as did Mr. Taylor, is to segregate a sub-population of higher use low-income customers and to argue that the consumption level of that higher-use sub-population is somehow representative of the low-income customer base as a whole. His argument cannot legitimately be used as a basis for decisionmaking.

D. Natural Gas Conversions.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING SCREENING CUSTOMERS FOR CAP ELIGIBILITY WHEN THEY CONVERT TO NATURAL GAS FROM NON-GAS HEATING FUELS.

A. Mr. Adamo opposes my recommendation that UGI screen customers for CAP eligibility when those customers convert to natural gas from non-gas heating fuels. My recommendation is for UGI to "screen customers *<u>who the Company assists in their conversion</u>* to natural gas in order to identify those converted customers as Confirmed Low-Income customers and to enroll those customers in CAP where appropriate." (OCA St. 4 at 4 – 5).

Mr. Adamo objects to my recommendation by responding to a proposal that was not made. Mr. Adamo states, for example, that "the Company on average receives approximately 9,000 natural gas conversion leads annually, *__all of which would need to be screened__* under Mr. Colton's recommendation." (UGI St. No. 12-R at 27) (emphasis added). Moreover, Mr. Adamo asserts that, under my recommendation, UGI Gas would be required "to track and store income and occupant information for *__prospective__* customers." (Id.) (emphasis added). Neither of those statements is accurate.

Mr. Adamo concedes that the Company identified only 1.5% of the 2021 homes it converted to natural gas as Confirmed Low-Income customers. Moreover, it enrolled only half of those Confirmed Low-Income customers into CAP (43 of the 85). He does not deny that these numbers are likely to substantially under-count the number of low-income customers that are being converted. Nor does he deny that those low-income customers will bring the payment troubles that other low-income customers experience on to the system when they become customers.

The process of identifying Confirmed Low-Income customers at the time of natural gas conversion would be no more difficult than the process of identifying Confirmed Low-Income customers at any other point in time. And, just as UGI Gas does not need to "track and store income and occupant information" for its existing Confirmed Low-Income customers, it would not need to do so for its Confirmed Low-Income customers identified through the gas conversion process.

Mr. Adamo's objections to identifying Confirmed Low-Income customers at the time of gas conversion, and to enrolling those customers into CAP when appropriate, do not address or rebut the substantive need for, or benefits from, doing so. My recommendation should be adopted.

E. Measurable Outcome Objectives.

Q. DOES MR. ADAMO OPPOSE CREATING MEASURABLE OUTCOME OBJECTIVES BY WHICH TO TRACK UGI GAS UNIVERSAL SERVICE PERFORMANCE?

A. Yes. Referring to the notion of having measurable outcome objectives by which to track UGI Gas performance as "drastic and unprecedented," Mr. Adamo opposes the adoption of such outcome objectives. He urges that the creation of such outcome objectives should be pursued only within the context of the Company's Universal Service and Energy Conservation Plan (USECP) proceedings. (Adamo, at 10). Indeed, Mr. Adamo asserts the proposition that "'all aspects' of Universal Service Programs should be addressed in utilities' individual USECP proceedings, as opposed to base rate cases." (UGI St. No. 12-R at 10).

The fallacy of Mr. Adamo's reasoning is demonstrated by the fact that, if nothing else, UGI Gas collects its universal service costs through rates. The structure and extent of rate recovery of universal service costs is not consigned to the USECP proceedings.

Moreover, the fallacy of Mr. Adamo's reasoning is demonstrated by the fact that, by definition, the Outcome Objectives do not address the content of the UGI Gas USECP. Indeed, establishing measurable outcome objectives in a rate case, and leaving the question of how to achieve those objectives to the USECP proceeding, is the most appropriate process. Through establishing the outcome objectives, the Commission establishes a process by which to assess whether, as with any other UGI Gas expenditure, ratepayer dollars are being spent effectively and efficiently. Considering the efficiency of utility operations is the function of a rate case, not the function of a USECP proceeding. The USECP proceeding is the proceeding where UGI Gas presents to the Commission what it plans to do (i.e., its universal service activities). A rate case is the appropriate place for the Commission to decide how it wishes to measure the effectiveness (and efficiency) of what the expenditure of ratepayer money is accomplishing (i.e., the outcomes).

Q. DO YOU HAVE ANY FINAL RESPONSE TO MR. ADAMO'S ASSERTION THAT THE QUESTION OF WHETHER ESTABLISHING MEASURABLE OUTCOME OBJECTIVES SHOULD ONLY BE UNDERTAKEN IN A UNIVERSAL SERVICE PROCEEDING.

A. I understand that the Commission recently affirmed its prior decisions stating that "it was not appropriate to consider proposals relating to a public utility's energy burdens, CAP, and other universal service program issues within the context of a base rate proceeding. . ." (Pennsylvania PUC v. Aqua Pennsylvania, Docket R-2021-3027385, at 333, May 12, 2022). The Outcomes Objectives proposed in my Direct Testimony are specifically designed to be in compliance with this decision. UGI, itself, raised the issue of the impact of this rate proceeding on low-income customers. UGI Gas asserted that this rate case would have *no adverse impact* on low-income customers *because of the Company's CAP*. (CAUSE-PA-I-1). My recommended Outcome Objectives are designed to determine whether UGI is correct in making that assertion. It would be unreasonable to allow UGI Gas to rely on assertions about the effectiveness of CAP in protecting low-income customers, made in support of its rate hike request, and to deny other parties the right even to present a mechanism by which to measure whether UGI Gas is correct in its assertion. Moreover, Mr. Adamo errs in asserting that any discussion of low-income impacts of a rate proceeding, and available mechanisms to mitigate those adverse impacts, are equivalent to a discussion of the Company's universal service programs. My Objective #1, for example, involves not the design and operation of the Company's universal service programs but rather simply whether UGI is adequately identifying its Confirmed Low-Income customers. My Outcome Objective #2 does not involve decisions about the design and operation of the Company's CAP, but rather simply whether the Company is adequately enrolling customers in that program, irrespective of how that program is designed and implemented. My Outcome Objective #3 does not involve decisions about the design and operation of the Company's CAP, but rather simply whether the Company's program is serving to protect its lowest income customers, a direct measurement of whether the Company is correct in asserting that there are no adverse impacts on low-income customers because of the CAP.

The fact is that UGI Gas made the following assertion:

> The Company's proposed rate increase will not impact CAP payments set at a percent of income or a minimum payment. However, as of the date of this response,

> approximately 51% of UGI CAP customers have their CAP payment set at their average monthly bill. Upon income re-certification, these average monthly bill CAP payments could be impacted in an amount up to the approved rate increase. Also, no CAP Customer would pay more than their applicable percentage of income calculation, set forth in the Company's USECP.
>
> As a result, UGI is unable to estimate the impact of the proposed rate increase to CAP participant's payment amounts.

(CAUSE-PA-1-1). It would be the height of unreasonableness to allow UGI to make these assertions about the impact of participating in CAP on protecting low-income customers from the adverse impacts of UGI's rate hike request, but then to deny any opportunity to propose a mechanism to measure the number and type of customers who are *not* participating in CAP.

Finally, my testimony is specifically designed within the constraints of the Commission's prior Order. The Commission's Aqua decision did not bar any consideration of the particular impacts of rates cases on low-income households. It instead stated that it was inappropriate to consider proposals "relating to a public utility's energy burdens, CAP, and other *universal service program issues*." (emphasis added).

Given the adverse impacts of *this rate case* on low-income customers, it establishes a mechanism by which to determine the number and nature of customers *not* participating in UGI's universal service programs. It then entirely leaves the "program issues" involving the design of appropriate universal service program responses to the Company, to stakeholders, and to the Commission, to consider within the context of reviewing the Company's universal service programming decisions in the review of USECPs.

Q. IS MR. ADAMO'S TESTIMONY INCONSISTENT WITH ANY OTHER TESTIMONY OFFERED BY THE COMPANY?

A. The Rebuttal Testimony of UGI witness Brown asserts that "In particular, inflation has significantly increased in recent months, and continues to do so. The material impacts of this inflation must be called out here as an important matter. The consumer price index ("CPI") jumped 8.5% in March 2022 from 12 months earlier, the sharpest year-over-year increase in over 40 years (since 1981). Just 1 recently, the April 2022 inflation numbers were reported to be 8.3%. As a result, the Company is proposing several key inflation-related adjustments in its rebuttal case. . ." (UGI St. !-R, at 3 – 4).

Mr. Brown continues to argue that "Inflation has broad and pervasive impacts on the Company's operations and is expected to touch almost every daily activity that UGI Gas undertakes. However, the Company is not proposing numerous specific adjustments for the anticipated increased operating expenses related to inflation, other than those noted above. I believe the Commission should consider the overall economic climate and these inflationary pressures on the cost of goods and services that the Company procures as part of providing safe and reliable service when deciding the merits of the Company's requested base rate increase." (Id., at 6).

The identical comments could be made about the pernicious impacts of inflation on ratepayers in general, and on low-income ratepayers in particular. It would be absolutely accurate to say, as well, that "inflation has broad and pervasive impacts on a household's operations and is expected to touch almost daily activities that a household undertakes. The Commission should consider the overall economic climate and these inflation pressures on the cost of goods and services that a household procures as part of living a safe and healthy life when deciding the merits of the Company's requested base rate increase."

This testimony of Mr. Brown is inconsistent with Mr. Adamo's objections to proposals to create measurable Outcome Objectives to determine the Company's performance in protecting low-income customers not enrolled in its universal service programs. Rather than allowing the Commission to establish ways to measure how well low-income customers are protected, Mr. Adamo would have the Commission delay even considering what should be measured until the next UGI USECP proceeding which would not even *begin* until the Company files its next USECP in April 2025. In the meantime, UGI Gas seeks rate relief (including an extra adder to its return on equity) based on "inflationary pressures." (UGI St. 1-R, at 6) ("the Company's exposure to inflationary forces outside the areas it has quantified above represents increased financial risk for the Company and further supports the Company's claimed cost of equity. . .")

Q. PLEASE RESPOND TO MR. ADAMO'S OBJECTION THAT ESTABLISHING MEASURABLE OUTCOME OBJECTIVES SHOULD ONLY BE UNDERTAKEN THROUGH A PUC RULEMAKING PROCEEDING.

A. Mr. Adamo argues that establishing measurable outcome objectives should only be taken through a PUC rulemaking proceeding. He argues that the same outcome objectives should be applied to every utility. He states:

> …if adopted, as part of this proceeding, these outcome objectives would only apply to UGI Gas. If that happens, UGI Gas would be subject to regulatory standards different than those applied to every other NGDC in Pennsylvania.

> However, all NGDCs in Pennsylvania should be evaluated under the same regulatory standards. Therefore, Mr. Colton's proposal should be raised, if at all, within the context of a statewide rulemaking proceeding which would permit participation from all stakeholders.

UGI St. No. 12-R at 15. Mr. Adamo does not explain *why* the same outcome objectives should be applied to all natural gas utilities in Pennsylvania. Given that measurable outcome objectives are designed as a mechanism to determine how effectively and efficiently a utility is using ratepayer dollars, it is entirely possible that such outcome objectives might differ between utilities. The outcomes which the PUC might seek to measure for an urban utility may differ from the outcomes the PUC might seek to measure for a rural utility. The outcomes for a utility with a large *very* low-income population (e.g., households with income less than 50% of Poverty Level) may differ from a utility with fewer very low-income customers.

As I stated in my Direct Testimony, "[t]he key concepts of. . .performance-based management are the need to define clear agency missions, set results-oriented goals, measure progress toward achievement of those goals, and use performance information to help make decisions and strengthen accountability." (OCA St. 4 at 24). It is entirely possible that different utilities would have different "results-oriented goals" programs toward which the PUC deems it necessary to track. It is entirely possible that different utilities would need different results-oriented goals "to help make decisions and strengthen accountability."

Moreover, Mr. Adamo's objection in this regard is not consistent with his other recommendation. Mr. Adamo also recommended that establishing results-oriented measurable outcome objectives be undertaken in UGI Gas' USECP proceeding. UGI St. No. 12-R at 10. Even if that were to occur, which it should not, each utility's USECP proceeding would involve individual proceedings. Mr. Adamo's own internal inconsistency demonstrates the fallacy of his arguments.

Q. PLEASE RESPOND TO MR. ADAMO'S ARGUMENT THAT UGI GAS ALREADY REPORTS DATA ON UNIVERSAL SERVICE PERFORMANCE.

A. Mr. Adamo argues that my recommended measurable outcome objectives are not needed because UGI Gas already tracks universal service data and reports that data to the PUC's Bureau of Consumer Services. (UGI St. No. 12-R at 15 -16). This argument, however, does more to support my recommendation than to detract from it. My measurable outcome objectives do not require new data collection on the part of UGI Gas. Even Mr. Adamo concedes that while it tracks and reports information, it has not established any performance standards which that information is used to inform. He further states that "the Commission has not developed Universal Service regulations, performance standards, or metrics that NGDCs must meet as compared to other NGDCs." (UGI St. No. 12-R at 16). Mr. Adamo's argument in this regard errs in the same two respects I discuss above. First, the purpose of the measurable outcome objectives is not to establish standards by which to compare one natural gas utility to another. Instead, the use of outcome objectives is to define utility-specific results-oriented goals, to measure the progress of a utility toward achievement of its own utility-specific goals, and to use performance information to help make utility-specific decisions and strengthen utility-specific accountability. Second, as I state above, there is no necessary reason for all utilities to have the same measurable outcome objectives. Different utilities may have different goals that are needed to allow it to measure progress toward, to make decisions, and to strengthen accountability.

Q. PLEASE RESPOND TO MR. ADAMO'S OBJECTIONS TO THE USE OF OUTCOME OBJECTIVES GENERALLY BY WHICH TO MEASURE UGI GAS PERFORMANCE.

A. In his Rebuttal Testimony, Mr. Adamo objects to the creation of ***any*** measurable outcome objectives by which to measure UGI Gas performance. He argues that using CAP data for comparative purposes from other NGDCs is inappropriate "given their distinctive customer populations, demographics, and service territories; that my proposed objectives and the anticipated results are "largely out of the Company's control," and that additional actions which may influence customer behavior requires the deployment of additional and targeted resources. UGI St. No. 12-R at 16.

The nature of Mr. Adamo's responses are precisely the reasons why the Commission should establish measurable outcome objectives for UGI Gas. The fact that different utilities might have "distinctive customer populations, demographics, and service territories" is precisely the reason why a UGI Gas-specific outcome objective should be established. Mr. Adamo's objection in this regard is inconsistent with his objection that uniform outcome objectives should be established for all utilities in a statewide proceeding rather than having utility-specific outcome objectives such as I propose in this proceeding.

Mr. Adamo's objection is also inconsistent with his own testimony on other issues in this proceeding. With respect to customer satisfaction, Mr. Adamo argued that "the Company's performance regarding customer satisfaction is very high as based on the Company's performance in JD Power East Large Residential Gas Utility. UGI Gas maintained the second highest score from 2015 through 2021, with the Company being number one in 2014. The Company was among 35 utility companies nationwide recognized as "Easiest to do Business With" in the 2021 and 2022 Cogent Syndicated Utility Trusted Brand & Customer Engagement™ Residential study. . ." (UGI St. No. 12-R at 9). In making that argument, the fact that other utilities might have "distinctive customer populations, demographics, and service territories" did not seem to bother Mr. Adamo.

Moreover, Mr. Adamo's assertion that the "anticipated results are largely out of the Company's control" is not necessarily true. Having never previously established measurable outcome objectives, UGI Gas does not know what results are or are not "out of the Company's control."

Finally, Mr. Adamo's assertion that "additional actions which may influence customer behavior require the deployment of additional and targeted resources." His conclusion that the only possible response is to take "additional actions" which would "require the deployment of additional and targeted resources" is not necessarily accurate. Through the use of measurable outcome objectives, UGI Gas could determine what it is currently doing that is working, and what it is currently doing that is not working. It may choose to take ***different*** actions in the future rather than taking ***additional*** actions.

The fact that Mr. Adamo merely assumes, without knowing, that "anticipated results are largely out of the Company's control" and that the only possible responses are those which require the "deployment of additional and targeted resources" is evidence unto itself of the need to establish measurable outcome objectives by which to track UGI Gas performance.

Q. PLEASE RESPOND TO MR. ADAMO'S CRITICISM THAT YOU OFFERED NO "SOLUTIONS" IN YOUR PROPOSAL?

A. Mr. Adamo offers two related objections to my proposal to adopt measurable outcome objectives. First, he argues that "Mr. Colton has not outlined any specific measures, anticipated budget amounts which may be spent, or the appropriate cost recovery thereof." (UGI St. No. 12-R at 16). Second, he argues that "Mr. Colton fails to offer any solutions to achieve those outcomes. . .The Company believes Mr. Colton could be more constructive to identify actions which have proven effective. . ." (Id.)

Mr. Adamo's objections in this regard are not well-grounded as objections to the creation of measurable outcome objectives. As I explained in my Direct Testimony, the purpose of creating outcome objectives is to define what the utility should seek to accomplish. The means by which to pursue accomplishing those objectives is left to the utility to decide. The utility may well seek the advice of external stakeholders, but the development of the specific strategies and tactics to employ is left for the utility to propose in its USECP.

Moreover, Mr. Adamo's objection is counter to the role of a rate case. A rate case is the time and place to determine how the Commission will measure the effectiveness and efficiency of the use of ratepayer dollars. Decisions on how to achieve the objective will be left to the utility (subject to review through the USECP process). My decision to leave proposing solutions to the PUC process designed to consider such solutions was intentional.

Q. DID MR. ADAMO OBJECT TO EACH OF THE THREE MEASURABLE OUTCOME OBJECTIVES YOU PROPOSE?

A. Yes. I will address his objection to each outcome objective in turn. First, Mr. Adamo objected to my proposed Outcome Objective #1 which measures the percent of Confirmed Low-Income UGI Gas customers of the total number of estimated low-income UGI Gas customers. He argues that the number of estimated low-income customers is "based upon census data analyzed by Penn State University, which is then provided to the Commission. As such, the census data provided to the Company does not provide any level of information at a customer-specific level; it is only a total for the estimated population." (UGI St. No. 12-R at 18). It is not clear what objection Mr. Adamo is making at this point. The fact that the Census data does not provide "information at a customer-specific level" does not affect the proposed outcome objective. If Mr. Adamo believes that the information that the PUC has Penn State University either over- or under-counts the estimated number of low-income customers, his dispute is with the PUC, not with the proposed outcome objective. In addition, Mr. Adamo argues that "While a master detailed list of all customers and incomes within the UGI Gas service territory would be useful in assigning CLI status to customer accounts, the privacy and protection of customers' personal information is an overriding concern." (Id.) Nothing, however, in the proposed Outcome Objective #1 requires UGI Gas to have a "master detailed list of all customers and incomes within the UGI Gas service territory." His objection on this basis is a red herring that should be rejected.

Mr. Adamo further argues that UGI Gas has increased the percentage of its Confirmed Low-Income customers since 2018. (UGI St. No. 12-R at 19 – 20). He does not acknowledge, however, that despite that improvement, UGI Gas still has a lower percentage than every other Pennsylvania natural gas utility other than PECO Gas. (UGI St. No. 12-R at 20). The fact that its increase is as high as it is merely reflects how poorly UGI Gas was performing in 2018. It is certainly not evidence that UGI Gas is performing well with respect to the percentage of estimated low-income customers (as set by the PUC) that have been identified as Confirmed Low-Income.

The Commission should adopt my proposal to establish, for UGI Gas, a measurable outcome objective that UGI Gas should achieve a Confirmed Low-Income identification rate, as a percentage of estimated low-income customers, no less than the Confirmed Low-Income identification rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).

Q. HOW DO YOU RESPOND TO MR. ADAMO'S OBJECTION TO YOUR SECOND PROPOSED OUTCOME OBJECTIVE?

A. Mr. Adamo objects to using the measurement of the percent of Confirmed Low-Income customers that have been enrolled in CAP as my proposed measurable Outcome

Objective #2. Similarly to his objection above, Mr. Adamo argues that UGI Gas "has materially improved CAP participation rates from just four years ago." (UGI St. No. 12-R at 21).

Mr. Adamo further argues that there are "four key reasons for CAP exits. Customers are moving to a new residence, failing to recertify, choosing a payment arrangement, and/or failing to pay." (UGI St. No. 12-R at 21). He does not explain why the "four key reasons for CAP exits" is the primary factor driving CAP participation rates. His reference to these exits should not be used as a basis for decisionmaking. In addition, however, Mr. Adamo's own testimony indicates the need for, and reason to create, measurable outcome objectives. He argues that "Notable trends included the increase in CAP failure to recertify post COVID-19 *even with significant outreach efforts*." UGI St. No. 12-R at 21) (emphasis added). The fact that the outcome being sought is not being achieved by the activities being implemented, an ongoing review of the desired outcomes should not result in a continuation of the ineffective activities. Instead, UGI Gas should be asking what can be done differently or more effectively in order to improve the outcomes. Mr. Adamo has the review process backwards. He assumes that the activities of the utility will remain constant and the outcomes are what should differ. Instead, the outcomes should remain constant and UGI Gas should be considering what it could be doing differently.

It is important to remember that the measurable outcome objectives that I recommend are not pulled out of thin air. The proposed measurable outcome objectives simply assess whether UGI Gas is achieving the same results as other Pennsylvania natural gas utilities are achieving (excluding UGI Gas). In this regard, Mr. Adamo's argument that CAP enrollment decreased in 2021 because the Commission again allowed utilities to impose a recertification requirement that had not been imposed during the height of COVID-19. The thing is that *every* utility would have experienced that same impact. A decrease in CAP participation rate due to a failure to recertify when the Commission again allowed CAP recertification to be required has no impact on the proposed Outcome Objective #2. To discuss the failure to recertify is another red herring that should be rejected.

The broader problem with Mr. Adamo's analysis is the same as above. The fact that the data shows that "the Company has materially improved CAP participation rates from just four years ago" is not a failure of the objective. It instead shows the success of, and need for, the Outcome Objective. As I indicate both above and in my Direct Testimony, the use of a measurable outcome objective is to set results-oriented goals, *measure progress toward achievement of those goals*, and use performance information to help make decisions and strengthen accountability.

Mr. Adamo's analysis is not a demonstration that the proposed outcome objective is inappropriate or doesn't work. In fact, it demonstrates quite the opposite. The Commission should adopt my recommended Outcome Objective #2, that UGI Gas should achieve a CAP participation rate, as a percentage of Confirmed Low-Income customers, no less than the CAP participation rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).

Q. WHY DOES MR. ADAMO OBJECT TO YOUR THIRD RECOMMENDED OUTCOME OBJECTIVE?

A. Mr. Adamo objects to my recommended Outcome Objective #3 on the grounds that the Company's high default rates in 2022 can be attributed to a failure to recertify once the Company, pursuant to PUC order, again began to require CAP recertification. UGI St. No. 12-R at 21 -22. His objection, however, does not specifically relate to my proposed Outcome Objective. My recommended Outcome Objective is that UGI Gas should achieve a CAP default rate as a percentage of participants ***in the lowest poverty level range*** that is no more than the CAP default rate in that poverty level range for Pennsylvania gas utilities as a whole. (emphasis added). Nothing that Mr. Adamo discusses addresses that specific outcome objective.

Mr. Adamo objects to my critique of UGI Gas' performance relative to this proposed Outcome Objective. His use of 2022 data showing reasons for high overall default rates in 2022, however, does not relate to my critique. In my critique, I explicitly limit my discussion to pre-COVID data:

> In 2019, according to the most recent BCS annual report on Universal Service Programs and Collections Performance,[3] UGI had a CAP default rate for customers with income below 50% of Poverty, which is my proposed Outcome Objective #3, that was higher than the statewide average default rate for gas utilities, and was higher than every other gas utility excepting PGW."

(OCA St. 4 at 31).

In addition, his discussion of 2022 data does not rebut the applicability of my recommended Outcome Objective #3. My recommended Outcome Objective #3 is limited to CAP participants with income less than 50% of Poverty. This is the population that the Commission has expressed particular concern for. (see e.g., Final Order, at 79, Docket No M-2019-3012599) (emphasis added). Nothing that Mr. Adamo presents relates to the exit rates for this population that has previously been identified by the PUC as being of particular concern. Indeed, Mr. Adamo's prior testimony, where he states that the 2022 increases in the failure to recertify could be attributed to customers who experienced temporary income disruptions, only later to return to their pre-COVID income levels (and thus no longer need CAP) is evidence that the population failing to recertify in 2022 does not fall within this very low-income population (i.e., below 50% of Poverty) toward which the proposed Outcome Objective #3 is directed.

Overall, the very fact that UGI Gas seeks to divert attention from the very low-income population of concern by focusing its attention exclusively on the CAP population as a whole is evidence of the need for this proposed Outcome Objective directed to the very low-income population.

Q. PLEASE RESPOND TO MR. ADAMO'S OPINION REGARDING THE PROPRIETY OF IMPOSING REWARDS AND PENALTIES BASED ON MEASURABLE OUTCOME OBJECTIVES?

A. Mr. Adamo objects to the use of rewards and penalties as a response to the extent to which, if at all, UGI Gas achieves the measurable outcome objectives I recommend in this proceeding. Even then, Mr. Adamo asserts that the only system of rewards and penalties would involve an adjustment to the UGI Gas return on equity. (Adamo, at 15). He asserts that "Such a system would constitute performance-based rates, a form of alternative ratemaking that the Commission can only approve upon 'an application by a utility in a base rate proceeding.'" (UGI St. No. 12-R at 15). At the least, Mr. Adamo's objection is premature. Even if Mr. Adamo were correct that the only system of rewards and penalties would involve an adjustment to the UGI Gas return on equity, which he is not, no system of "rewards and penalties" has been proposed in this proceeding. Mr. Adamo is objecting to a proposal that has not been made.

Q. PLEASE RESPOND TO MR. ADAMO'S REBUTTAL TESTIMONY REGARDING THE ALLOCATION OF UNIVERSAL SERVICE COSTS.

A. Mr. Adamo states in his Rebuttal Testimony that "I want to make clear that to the extent that Mr. Colton's testimony is, or could be, construed as a proposal to reallocate universal service costs as a part of this proceeding, the Company opposes this proposal." (UGI St. No. 12-R at 50). As I indicated in my Direct Testimony, no proposal to reallocate universal service costs has been advanced in this proceeding. There is no proposal for the Company to "oppose."

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Re: Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. – Gas Division	:	

VERIFICATION

I, Roger D. Colton, hereby state that the facts set forth in my Surrebuttal Testimony, OCA Statement 4SR, are true and correct (or are true and correct to the best of my knowledge, information, and belief) and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: May 27, 2022
*329515

Signature: Roger D. Colton

Consultant Address: Fisher, Sheehan, & Colton
34 Warwick Road
Belmont, MA 02478

OCA Discovery Exhibit 1 - UGI Response to CAUSE-PA Set II-10

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set II (1 thru 16)
Delivered on March 21, 2022

CAUSE-PA-II-10

Request:

For each year in the past 5 years, disaggregated by year, what would the residential customer bill have been for a household at average usage levels if WNA had been in effect under the following parameters?

a. No dead band
b. 1% dead band
c. 3% dead band
d. 5% dead band

Response:

UGI Gas does not have the ability to recompute individual historic bills for determination of specific WNA billing impacts. However, please see Attachment CAUSE-PA-II-10 for a proxy of what the calculated annual WNA impact would have been to a residential bill over the past five years using an estimated average usage across the various deadbands. In addition, please see Attachment CAUSE-PA-II-9 for a five-year history of a monthly residential bill using the same estimated average usage.

Prepared by or under the supervision of: John D. Taylor

UGI Utilities, Inc. - Gas Division
WNA Scenario Analysis (Fiscal Years 2017 - 2021)
Estimated Annual Impact to R/RT Customer at Current Rates
charge (credit) to customer

	No Deadband	1% Deadband	3% Deadband	5% Deadband
Fiscal 2017	$ 39.05	$ 37.39	$ 34.11	$ 30.84
Fiscal 2018	$ 7.81	$ 8.65	$ 10.28	$ 10.68
Fiscal 2019	$ 6.17	$ 6.58	$ 5.34	$ 3.69
Fiscal 2020	$ 35.35	$ 32.87	$ 28.77	$ 25.48
Fiscal 2021	$ 29.59	$ 26.71	$ 22.60	$ 19.32

Assumptions:

Modeling based on estimated annual usage per UGI Gas Exhibit E for R and RT customers of 844 ccf using currently effective rates.

For modeling the estimated annual usage was allocated by month using the following percentages:

OCT	5.8%	JAN	20.1%	APR	7.0%	JUL	1.4%
NOV	11.5%	FEB	16.3%	MAY	3.1%	AUG	1.5%
DEC	15.8%	MAR	13.4%	JUN	1.8%	SEP	2.3%

Monthly baseloads were calculated using the daily usage calculated during the period of June-September multiplied by the number of days in each month

Composite historical and normal HDD data used as found on SDR-RR-11(a). Assumes all customers' calculations are based on the composite HDD information. If approved, actual WNA calculations would be specific to each customer's delivery region.

The above amount represents an approximation of WNA charges/credits only and does not reflect any other additional riders that may be applied such as DSIC or STAS

The underlying model assumes that all customers are billed and weather is measured based on calendar month which will differ from actual billing and weather periods that would be used if implemented. See Rider K in UGI Gas Exhibit F for proposed tariff language.

OCA Discovery Exhibit 2 - UGI Response to CAUSE-PA Set V-1, 2

CAUSE-PA-V-1

Request:

Using the criteria utilized by UGI for calculation of its Weather Normalization Adjustment (WNA), for each year since 2011 please indicate whether the year was warmer or cooler than normal and the percentage warmer or cooler as measured in heating degree days.

Response:

Please see Attachment CAUSE-PA-V-1.

Prepared by or under the supervision of: John D. Taylor

Attachment CAUSE-PA-V-1
J. D. Taylor
Page 1 of 1

UGI Utilities, Inc. - Gas Division
2011-2021 Heating Degree Days[1]
for the period of October-May

Fiscal Year	Actual HDD	Normal HDD	Variance to Normal HDD	
2011	5,796	5,439	7%	Colder
2012	4,614	5,439	15%	Warmer
2013	5,483	5,439	1%	Colder
2014	6,132	5,439	13%	Colder
2015	5,923	5,439	9%	Colder
2016	4,847	5,439	11%	Warmer
2017	4,913	5,439	10%	Warmer
2018	5,475	5,439	1%	Colder
2019	5,345	5,439	2%	Warmer
2020	4,990	5,439	8%	Warmer
2021	4,991	5,439	8%	Warmer

[1] *SDR-RR-11(a) used as data source*

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set V (1 - 2)
Delivered on April 18, 2022

CAUSE-PA-V-2

Request:

For each year since 2011, what would the total impact to residential revenue have been if UGI's proposed WNA had been in effect?

Response:

UGI Gas does not have the ability to recompute individual historic bills for determination of specific WNA billing impacts and, thus, cannot provide the specific information requested. However, as a proxy, please see Attachment CAUSE-PA-V-2 which computes approximate annual dollar impact assuming an average usage level across the various years using composite heating degree information, based on currently effective distribution rates (excluding rider rate impacts).

Prepared by or under the supervision of: John D. Taylor

UGI Utilities, Inc. - Gas Division
WNA Scenario Analysis (Fiscal Years 2011 - 2021)
Estimated Annual Impact to R/RT Customer at Current Rates and No Deadband
charge (credit) to customer

	Annual Estimated Impact
Fiscal 2011	$ (16.44)
Fiscal 2012	$ 59.61
Fiscal 2013	$ 0.82
Fiscal 2014	$ (31.25)
Fiscal 2015	$ (18.90)
Fiscal 2016	$ 48.09
Fiscal 2017	$ 39.05
Fiscal 2018	$ 7.81
Fiscal 2019	$ 6.17
Fiscal 2020	$ 35.35
Fiscal 2021	$ 29.59

Assumptions:

Modeling based on estimated annual usage per UGI Gas Exhibit E for R and RT customers of 844 ccf using currently effective rates.

For modeling the estimated annual usage was allocated by month using the following percentages:

OCT	5.8%	JAN	20.1%	APR	7.0%	JUL	1.4%
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DEC	15.8%	MAR	13.4%	JUN	1.8%	SEP	2.3%

Monthly baseloads were calculated using the daily usage calculated during the period of June-September multiplied by the number of days in each month

Composite historical and normal HDD data used as found on SDR-RR-11(a). Assumes all customers' calculations are based on the composite HDD information. If approved, actual WNA calculations would be specific to each customer's delivery region.

The above amount represents an approximation of WNA charges/credits only and does not reflect any other additional riders that may be applied such as DSIC or STAS

The underlying model assumes that all customers are billed and weather is measured based on calendar month which will differ from actual billing and weather periods that would be used if implemented. See Rider K in UGI Gas Exhibit F for proposed tariff language.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI Utilities, Inc. – Gas Division	:	

LIST OF THE EVIDENCE OFFERED BY THE
OFFICE OF SMALL BUSINESS ADVOCATE

The Office of Small Business Advocate ("OSBA") intends to introduce the following evidence into the record in the above-captioned proceedings at the hearings scheduled for June 2nd & 3rd 2022:

- OSBA Statement No. 1 and Exhibits RDK-1, RDK-2 and RDK-3: the Direct Testimony, Exhibits and Mr. Knecht's signed Verification

- OSBA Statement No. 1-R and Exhibit RDK-1R, the Rebuttal Testimony and Exhibit of Robert D. Knecht, and Mr. Knecht's signed Verification

- OSBA Statement No. 1-S and Exhibits RDK-S1 and RDK-S2: the Surrebuttal Testimony and Exhibits of Robert D. Knecht and Mr. Knecht's signed Verification

COMMONWEALTH OF PENNSYLVANIA

April 20, 2022

Administrative Law Judge Joel H. Cheskis
Administrative Law Judge Gail Chiodo
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Gas Division / Docket No. R-2021-3030218

Dear Judge Cheskis and Judge Chiodo:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI UTILITIES, INC. (Gas Division)	:	

Direct Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design

Date Served: April 20, 2022

Date Submitted for the Record: ____________________________

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. <u>Introduction and Overview</u>

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am an independent economic consultant, specializing in the preparation of analysis and expert testimony in the field of regulatory economics. For more than 30 years, I was a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140, and I served as Treasurer of that firm for 15 years. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and an M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance.

I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). I have represented the OSBA before the Pennsylvania Public Utility Commission in a variety of matters since 1994. I have provided testimony in a variety of proceedings involving both the Electric and Gas Divisions of UGI Utilities, Inc., its former subsidiaries Penn Natural Gas and Central Penn Gas, and the subsidiaries' predecessor utilities PG Energy, PPL Gas, and PFG/North Penn Gas, beginning in 1996. My résumé and a listing of the expert testimony that I have filed in utility regulatory proceedings during the past five years are attached in Exhibit RDK-1.

Q. What is the purpose of this testimony?

A. I was retained by the OSBA to review the filing of UGI Utilities, Inc. – Gas Division ("UGI Gas" or "the Company"), to evaluate whether the Company's cost allocation, revenue allocation, and rate design proposals are consistent with sound regulatory economics and policy and are fair and reasonable to small business customers. Consistent with Pennsylvania practice, I have also been asked to provide OSBA's positions with respect to the Company's proposed weather normalization adjustment ("WNA") mechanism, and with respect to the claim for plant costs related to the heat content adjustment factor.

Q. Please summarize the Company's filing from a cost allocation/rate design perspective.

A. The salient features of the Company's proposal are as follows:

- The Company proposes a base rate increase of $82.3 million, or 12.8 percent of base rate revenues, for the fully projected future test year ("FPFTY") ending September 30, 2023.[1] This filing follows base rate cases in 2016, 2019, and 2020, summarized in Table RDK-1 below. Prior to the 2016 filing, UGI Gas had not filed a base rate since 1996.[2]

Table RDK-1
Recent UGI Gas Base Rate Increase Cases

Docket No.	Test Year Ending	Proposed Increase ($mm)	Award Amount ($mm)	Award Percent
R-2015-2518438	9/30/2017	$58.6	$27.0	46%
R-2018-3006814	9/30/2020	$71.1	$30.0	42%
R-2019-3015162	9/30/2021	$74.6	$20.0	27%
Total		**$204.3**	**$77.0**	**37.7%**
R-2021-3030218	9/30/2023	$82.7	--	--

The three prior proceedings' revenue requirements were resolved by settlement.

- The Company justifies the proposed rate increase as a result of its significant capital spending, for both asset replacement and system expansion. The Company's revenue requirement claim includes a book equity share of capital of 55.1 percent and an allowed return on equity of 11.2 percent.[3]

[1] The Company also proposes a modest change in the Merchant Function Charge ("MFC") which results in an additional increase of $0.5 million related to uncollectibles for gas sales.

[2] In the intervening years, UGI Gas acquired PG Energy in 2006 and PPL Gas Utilities, Inc. in 2008. These utilities were operated and regulated independently, and then merged in 2018. Virtually all regulatory and rate differences between these companies have been eliminated, save for certain continuing rate differentials, which are addressed further herein.

[3] Each 100 basis points (1.0 percent) in allowed RoE results in about $25 million in revenue requirement at statutory income tax rates, all other factors being equal.

- In its cost of service allocation study ("CSAS"), the Company generally follows the methodology that it has advanced in the last few base rate proceedings. Mains costs are allocated using an "average and excess" allocation methodology with a non-standard weighting methodology. The results of the Company's CSAS indicate that the residential class ("Rate R/RT") exhibits a rate of return at current rates below system average, the small and medium commercial/industrial rate classes (Rates N/NT and DS) exhibit rates of return modestly above system average, and the large C&I (Rate XD) and interruptible (Rate IS) rate classes exhibit rates of return well above system average.

- The Company's proposed allocation of the rate increase among the rate classes reflects the results of its CSAS, summarized in Table RDK-2 below. Based on the Company's CSAS, the revenue allocation for all classes results in substantial progress toward cost-based rates.[4] The rate increase for the R/RT class is limited to just under 1.5 times system average, which results in a class rate of return at proposed rates that remains moderately below system average. Rate reductions for the XD and IS classes reflect the reset of the Distribution System Improvement Charge ("DSIC"), without any corresponding increase to base rate charges.

[4] In making this observation, I do not rely on the "indexed rate of return" metric used by the Company, because that metric (a) generally overstates progress toward cost-based rates, and (b) can in some cases incorrectly show progress toward cost-based rates when none exists. My conclusion is based on the revenue-cost ratio metric, as shown in RDK WP1.

Table RDK-2 UGI Gas Proposed Revenue Allocation: FPFTY Ending 9/30/2023			
Class	**Present Rates RoR**	**Dollar Increase ($000)**	**Base Rate Percent Increase**
R/RT	4.3%	$68.12	18.1%
N/NT	7.3%	$14.53	10.4%
DS	8.6%	$0.65	1.9%
LFD	9.4%	$1.53	3.4%
XD-Firm	14.0%	($0.96)	-2.6%
Interruptible*	13.5%	($1.05)	-4.4%
Total	**6.1%**	**$82.74**	**12.6%**
* Includes Rate IS and Rate XD-Interruptible. Source: RDK WP1			

- The Company's proposed rate design for the R/RT and N/NT classes (which together represent nearly 80 percent of present rate revenues) involve disproportionately large increases to the fixed monthly customer charges, at 36.6 and 27.7 percent respectively.

- The Company proposes to eliminate the rate differentials in Rates N/NT and DS between customers in the south and central operating areas and customers in the north district. This proposal results in intra-class north/other increase differentials of 18.4%/8.4% for Rate N/NT, and 24.7%/-4.1% for Rate DS. The Company argues that the large increase for customers in the north district are reasonable because they are within 2.0 times the 12.6 percent system average increase.

- The Company proposes to adopt a weather normalization adjustment ("WNA") mechanism for Rates R/RT and N/NT. This mechanism would adjust each customer's billing determinants for non-summer months to reflect the difference between actual and normal weather.

2. Cost Allocation

Q. What is a utility cost allocation study?

A. A utility cost allocation study ("CSAS") is an analytical tool that assigns the utility's test year total costs (i.e., the "revenue requirement") among the various utility rate classes. Pennsylvania electric and gas distribution utilities use an "embedded cost" approach to cost allocation, in which accounting book costs are assigned among the rate classes, rather than a marginal cost approach. Cost allocation analysts generally agree that costs should, to the extent practicable, be assigned among rate classes on the basis of "cost causation," such that costs caused by a particular class of customers are assigned to that class.

A CSAS generally involves a three-step process, in which costs are (a) segregated by function ("functionalization"), (b) further segregated by cost causation factor, notably throughput, peak demand, "excess" demand, and customer count ("classification"), and (c) allocated among the rate classes based on each class' contribution to the cost causation factor ("allocation").

Q. What purpose does the CSAS serve in a utility rate proceeding?

A. The CSAS informs both the assignment of the rate increase among customer classes ("revenue allocation") and the design of rates to recover those costs. Revenue allocation is often used to move rate revenue more into line with allocated costs from the CSAS for each rate class. For rate design, classified costs, such as customer-related and demand-related costs, are used to inform the development of specific rate charges, such as monthly customer and demand charges.

Q. What are the most important cost allocation issues for a natural gas distribution company ("NGDC") such as UGI Gas?

A. A CSAS allocates rate base and associated capital costs, distribution expense, customer accounts/service expense, expense, administrative/general ("A&G") expense and taxes.[5] Often, costs are allocated on a derivative basis, based on costs already allocated. For example, depreciation, income taxes and return are allocated in the same manner as or in

[5] Distribution, customer accounts/service and A&G expenses are collectively called operating and maintenance ("O&M") expense.

proportion to rate base. General plant and A&G costs are typically allocated based on some combination of overall plant, O&M expense or labor cost allocations. Thus, the overall results of a CSAS are substantially driven by the allocation of a few large asset accounts. These "big ticket" issues for NGDC cost allocation are generally:

- Classification of mains costs, potentially into peak demand, throughput and/or customer components. For UGI Gas, mains represent 50 percent of rate base.
- Allocation of meters and services costs. UGI Gas meters and services account for 32 percent of rate base.[6]
- Definition and derivation of the peak-demand allocation factor, including the treatment of interruptible load in the allocator.

My testimony in this proceeding addresses the mains cost allocation method and the development of the demand allocator. The Company reports that its mains and services plant allocation is based on direct assignment of costs based on plant records, which is the best method for those costs where reliable data are available. As such, I do not address that issue in detail.

As part of my evaluation, I first replicated the Company's CSAS using my own spreadsheet model, and then developed an alternative version that reflects the changes I propose in this testimony. Electronic versions of these models are filed with this testimony, denoted RDK WP1 and RDK WP2 respectively.[7]

Q. Please address the basics of embedded cost allocation of NGDC mains costs.

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[6] These percentages are based on rate base before the deferred tax offset.

[7] In my testimony in previous UGI Gas proceedings, I explained why it would be more reasonable for the Company to segregate Rate XD-Interruptible customers from those in the Rate IS class for cost allocation purposes, and I modified the CSAS accordingly. See OSBA Statement No. 1 at Docket No. R-2020-2019-3015162, pages 26-27. While I retain my view in this respect, I did not undertake that effort in this proceeding as it would not affect my conclusions.

A. NGDC mains costs are incurred to (a) interconnect the customers who take gas distribution service, and (b) provide sufficient capacity in each segment of the distribution system to meet the "design day" demands of firm service customers downstream from that segment.

With the enormous improvement in GIS and system modeling technology over the past few decades, one might think that NGDCs would be able to use that technology to specifically allocate the cost of individual mains segments to customers served downstream from those mains. In fact, UGI Gas developed such an approach for its 1996 base rates case. Alas, however, UGI Gas (and the other Pennsylvania NGDCs) continue to rely on hoary cost allocation methods, none of which rely on detailed modeling of how costs are actually incurred, and which produce radically divergent results depending on the method chosen.

In these traditional approaches to mains cost allocation, the first decision involves the "classification" of mains costs into costs that are "customer-related" and "demand-related." For those utilities that include a "customer-component" of mains costs, the classification method generally involves determining the "fixed" costs associated with a minimum-sized distribution system (or a statistically-modeled zero-volume system) and classifying that portion of the mains cost as customer-related. The conceptual logic for this method is flawed, of course, because there is no reason to conclude that the fixed costs for any particular mains segment are proportional to the number of customers served by that segment. However, some analysts argue that the cost to extend the distribution system, in terms of mains footage, is higher per unit of demand for smaller more geographically distributed customers than for larger customers or those concentrated in business districts. This logic would justify including some mechanism like a customer component to reflect these economies of scale in cost allocation. However, the existing methods for deriving a customer component are not based on this cost model.

The second consideration for mains cost allocation is the choice of the allocation factor for the "demand-related" costs. In Pennsylvania, the most common choices are the following:

Peak Demand: Costs are allocated in proportion to each class's share of system "design day" peak demand, which represents the capacity needed to serve the class under extreme weather conditions. The logic for this approach is that the mains must be sized to meet peak day demand.

Peak and Average ("P&A"): Costs are allocated based on a weighted mix of design day peak demand and average day demand.[8] Weighting the two components is typically 50/50. This approach suffers from the conceptual flaw that no mains costs are caused by average day demand – if mains costs were sized based on average demands, gas customers would be without heat on the coldest days of the winter. A main sized to meet a 100 mcf per day load costs the same whether that main is used at 100 mcf per day on every day of the year, or if that main only averages 20 mcf per day over the course of the year.

Average and Excess ("A&E"): Costs are allocated based on a weighted mix of average demand and "excess demand," where excess demand is measured as the difference between each customer's design day demand and average demand. The standard weighting factor for the A&E allocator is to apply the system load factor to the average component of the allocator (and one minus the system load factor to the excess component). The traditional A&E method is essentially a peak demand method that is adjusted to reflect the diversity of customer load. Diversity refers to the difference between the sum of individual customer peaks and system-wide peaks. Thus, if all customers peak at the same time, there is zero load diversity. The A&E method can be arithmetically expressed as a linear combination of the peak demand allocator and an average demand allocator. More load diversity implies a higher weighting for the average demand component. In the special case where there is zero load diversity and the system load factor weighting is used for the allocator, the A&E allocator is arithmetically identical to the peak demand allocator. Because gas customers' peak demands are weather-related, NGDCs generally exhibit little in the way of demand diversity, and traditional A&E allocation factors are thus very similar to peak demand allocators.

Q. Does the Commission have a policy regarding mains cost allocation?

[8] Average day demand is the annual customer load divided by 365 days. Arithmetically, average day demand and annual consumption are identical for cost allocation purposes.

A. The Commission indicates that it does not have a standard policy regarding mains cost allocation, and that it intends to evaluate the issue on a case-by-case basis.[9] Nevertheless, in its recent decisions, the Commission has relied substantially on precedent with respect to mains cost allocation.[10] With respect to the issue of mains plant classification, the Commission has consistently rejected the inclusion of a customer component for mains costs (although it has approved the use of a customer component for joint-use electric distribution plant, where the cost causation logic is the same). Regarding the allocation method for mains, the Commission has approved both P&A and A&E methods, as summarized below:

National Fuel Gas (1994):	83 Pa. PUC 262 (1994)	P&A
PPL Gas (2007):	R-00061398	A&E
PGW (2007):	R-00061931	A&E
Columbia Gas (2021)	R-2020-3018835	P&A[11]
PECO Gas (2021)	R-2020-3018929	A&E

Further, in the 2021 PECO Gas matter, the Commission indicated that the A&E method was more appropriate than the P&A method used in the Columbia matter because PECO's *". . . distribution mains system is designed to meet the demands of its system on a design day that all customers can be served. . . . Therefore, we conclude that the excess demand component of PECO's distribution mains system garners considerable weight in the balance of mains costs."*[12] As Columbia Gas (and all other Pennsylvania NGDCs) also size their mains to meet design day demand, it is unclear whether the Commission made some specific finding regarding the topology of the PECO Gas system that makes the A&E method more appropriate. As a participant in both the PECO Gas and Columbia Gas

[9] Non-Proprietary Version Opinion and Order, Docket No. R-2020-3018929, Order Entered June 22, 2021 ("PECO Order"), at 230-231.

[10] Opinion and Order, Docket No. 2020-3018835, Order Entered February 19, 2021 ("Columbia Order"), at 213-214.

[11] In its decision, the Commission correctly observed that no party offered an A&E approach in the proceeding. Columbia Order at 214.

[12] PECO Order, at 229.

proceeding, I do not recall that any evidence was presented that PECO Gas' distribution planning criteria were different from those used by Columbia Gas. As such, the Commission's logic in the PECO Gas matter would appear to reasonably apply to all Pennsylvania NGDCs.

Q. What approach does UGI Gas use in this proceeding?

A. The Company classifies all mains costs as demand-related (i.e., zero customer component) and allocates the costs using a modified load-factor weighted A&E method.

For the large industrial Rate XD-F and XD-I customers, the Company directly assigns the cost of the specific mains used by those customers to the respective classes. These customers are generally located in close proximity to interstate transmission lines, and the specific mains are identifiable. Thus, the average demands and peak demands for those customers are set to zero for the development of the class allocation factors.

However, in developing the load factor for developing the weighting factors for average demand and excess demand, the Company uses the system load factor including the XD customers, and it uses zero as the peak demand for all Rate IS and XD-I customers. Thus, the Company uses a load factor of 42.1 percent for weighting its A&E allocator, rather than the 26.9 percent that would result from a traditional interpretation of the A&E method.

The upshot of the Company's method is that the UGI Gas A&E factor is arithmetically equivalent to a P&A allocator that is weighted 79 percent peak, 21 percent average.[13]

While this particular mains cost allocation approach does not explicitly address any particular design features of the UGI Gas distribution systems, it does produce an allocation method that lies between the A&E and P&A methods recently approved by the Commission. I therefore accepted the Company's classification/allocation approach for mains cost in this proceeding.

Q. Please address the allocation of mains costs to interruptible customers.

[13] See RDK WP1 "Allocs" worksheet for supporting calculations.

A. In theory, interruptible customers can provide significant value to a gas distribution system, as those customers can be interrupted during periods of extreme weather or other stresses on the distribution system. Thus, the utility can use the interruptibility of these customers to avoid expanding capacity, and thus avoid costs. From a strict cost causation perspective, some analysts therefore argue that interruptible customers do not contribute to mains cost causation, and they assign a peak demand allocation factor of zero. In those cases, rates for interruptible customers are generally set based on value of service criteria, rather than allocated cost.

In this proceeding, the Company proposes to set the "excess" portion of the A&E allocator to zero for the interruptible customers, while including the average portion of demand in the allocator. In so doing, the Company implicitly treats interruptible customers as having a peak demand equal to their average demand. As a result, the allocation method results in an allocation of mains costs to these customers that lies between zero and the full cost share that would result if interruptible customers' peak demands were recognized. Thus, like the Company's A&E allocator in general, this approach has little in the way of cost causation logic, but it produces an allocation that lies between the extremes.

In this light, and recognizing that rates for Rate IS are set by negotiation, I do not contest this approach in this proceeding.

Q. How does the Company derive its design day demands to develop the excess demand allocation factor for its A&E method?

A. The Company's design day workpapers were provided in OSBA-I-4. Based on that workpaper, the Company's method is at follows:

1. Begin with the system-wide design day demand from last year's Section 1307(f) "PGC" proceeding;

2. Add in contract demands for large customers that were not included in the PGC proceeding;

3. Set the design day demands for the DS, LFD and XD-Firm customers at the contract demand levels;[14]

4. Split the remaining design day demand between the R/RT and N/NT classes based on a factor called "actual average consumption per customer per day" multiplied by number of customers in the class. It is necessary to develop a method to split the design day demand for these two classes because the classes are not daily metered, and the design day for the two classes (the "Core Market") is derived together in the PGC proceedings using a statistical regression methodology.

Q. Do you agree with this approach?

A. Based on the information that is currently available, I do not. First, it is incorrect to segregate design day demands between R/RT and N/NT customers based on average consumption. Such segregation must reflect the relative design day demands of the two classes. Second, the source for the Company's actual average consumption factors is not specified and is not clear. Third, the Company's methodology produces an anomalous result for the R/RT and N/NT classes, namely that the load factor for the Rate N/NT class is materially lower than that for the Rate R/RT class, at 19.7 percent and 21.9 percent respectively. In my experience, the load factors for residential and small commercial gas customers are either similar in magnitude, or the commercial class exhibits modestly higher load factors. Moreover, the Company's analysis in this case results in a significant shift in load factors since the last case, where the R/RT and N/NT load factors were 20.6 percent and 20.9 percent respectively.

Q. Did you conduct any independent analysis of the relative load factors of R/RT and N/NT customers?

A. I did. When daily metered data are not available, analysts can use monthly data to estimate the base load and heating load for a rate class, using either regression or simple arithmetic methods. I applied a regression method to both the monthly class data provided in response to OSBA-I-3, and to the more detailed monthly class data provided in the various

[14] The Company's workpaper indicates that it relies on daily firm requirements ("DFRs") for contract demands for the LFD and XD-F classes, and the maximum daily quantity ("MDQ") for Rate DS.

attachments to OSBA-I-18. I also applied a simple arithmetic method to the monthly data in OSBA-I-3. All of these analyses show the same pattern: the historical load factor for the N/NT class is modestly higher than that for the R/RT rate class. My analysis is attached to this testimony at RDK WP3.[15]

I therefore modified the Company's split of the design day demand between R/RT and N/NT customers to be consistent with the load factors derived in my analysis.

This is the only modification that I made to the Company's cost allocation methodology.

Q. How do the results of your modified CSAS compare to the Company's results?

A. Table RDK-3 below shows class rates of return at present rates for (a) the Company's CSAS, (b) my replication of the Company's CSAS in RDK WP1, and (c) my alternative CSAS with the modified peak demand allocators in RDK WP2. As shown, my replication matches the Company's results, and my alternative model produces modestly different returns for Rates R/RT and N/NT.

Table RDK-3
Comparative CSAS Results:
Class Rates of Return at Current Rates

	UGI Gas CCAS	RDK Replication	RDK Alternative
R/RT	4.33%	4.33%	4.09%
N/NT	7.28%	7.28%	8.13%
DS	8.61%	8.61%	8.61%
LFD	9.44%	9.44%	9.44%
XD-F	14.01%	14.01%	14.01%
Interruptible	13.46%	13.46%	13.46%
Total	**6.14%**	**6.14%**	**6.14%**
Sources: Exhibit D, RDK WP1, RDK WP2			

[15] In preparing this analysis, I also estimated implied design day demands for the DS and LFD classes. My analysis of the DS class produced load factor results that were similar to the Company's MDQ load factors. However, for the LFD class, my analysis implies a materially lower load factor than that implied by the Company's DFR method. I did not make an adjustment in this respect because service to LFD customers above the DFR is not guaranteed, but my analysis may imply that UGI Gas is implicitly providing more capacity under extreme weather conditions to the LFD customers than that implied by the DFRs.

3. <u>Revenue Allocation</u>

Q. What is revenue allocation?

A. Revenue allocation is the assignment of the dollar net increase or decrease to each of the Company's rate classes in a base rates proceeding. In contrast, *rate design* determines how the allocated revenue is recovered from individual ratepayers within each class. From a cost recovery standpoint, revenue allocation addresses *inter-class* cross-subsidization issues, while rate design addresses *intra-class* cross-subsidization issues.

Q. What are the basic principles for revenue allocation in regulated utility base rate proceedings?

A. In general, allocated cost is the primary criterion used by regulators in the revenue allocation process. Most utilities and regulators adopt a policy in base rates proceedings of attempting to move revenues more into line with allocated costs by varying the magnitude of the rate increases for the individual classes. However, regulators also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue allocation process are:

- the *gradualism* principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customers are avoided; and

- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively price-elastic demand. [16]

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. With this proposal, the ACOSS can be simulated at both present and proposed rates to

[16] See, for example, <u>Principles of Public Utility Rates</u>, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. Note that the criteria in this text apply to the overall development of a utility rate structure. The criteria that I discuss in this testimony are those that apply to the revenue allocation portion of the process, which is only one aspect of the development of utility rates.

evaluate the magnitude of "progress" has been made toward the policy of achieving cost-based rates.

As a practical rule-of-thumb, rate gradualism is often reflected in revenue allocation by limiting the increase for any particular class to 1.5 to 2.0 times the system average.

Q. Do you agree with the Company's proposed revenue allocation, as presented above?

A. I have two disagreements.

First, there I disagree that rate decreases should be assigned to the Rate XD and Rate IS classes. These customers are subject to negotiated rates, which have already been accepted by the customers. In particular, the Rate IS tariff requires that the negotiated rates be set based on the cost of alternative fuels. There is therefore no competitive need to provide rate reductions to these customers. I propose to set the rate increases for those customer classes at zero and (implicitly or explicitly) roll the current DSIC revenues into the regular rates.

Second, under my alternative CSAS, the Company's proposed revenue allocation is inequitable to the Rate N/NT class, as it would result in relatively small progress toward cost-based rates compared to the other rate classes. I therefore propose to further modify the Company's proposed revenue allocation by (a) setting the rate increase for the R/RT class at 1.5 times the system average increase (1.5 x 12.6% = 18.9%), and (b) set the increases for the N/NT, DS and LFD classes to produce equivalent progress toward cost-based rates.[17] Using the normalized revenue-cost ratio metric, my proposal results in the revenue allocation summarized in Table RDK-4 below, and detailed in RDK WP2.

Table RDK-4 RDK Alternative Proposed Revenue Allocation				
	Increase $mm	**Increase %**	**R-C Ratio Current Rates***	**R-C Ratio Proposed Rates***
R/RT	$71.45	18.9%	88.3%	93.8%
N/NT	$ 9.04	6.5%	114.4%	106.4%
DS	$ 1.38	4.1%	115.8%	107.0%
LFD	$ 0.88	2.0%	123.2%	110.4%
XD-Firm	$ 0.00	0.0%	145.3%	130.7%
IS/XD-I	$ 0.00	0.0%	152.8%	133.7%
Total	**$82.74**	**12.6%**	**100.0%**	**100.0%**

* Based on RDK proposed CSAS methodology in RDK WP2.
Source: RDK WP2

As shown in Table RDK-4, no class is assigned a rate decrease, no class exhibits an increase that is more than 1.5 times the system average, and every class makes material progress toward cost-based rates as measured by the revenue-cost ratio metric. The N/NT, DS and LFD classes all move a little more than halfway toward cost-based rates. For example, at present rates, the revenue cost ratio for Rate N/NT is 115.8%. As my proposed rates, the class moves to 107.0%, moving 8.8 (115.8 – 107.0) percentage points closer to cost-based rates, of the 15.8 percentage points needed to set rates at costs.

In making this proposal, I recognize that I assign a larger rate increase to the Rate DS class than that proposed by UGI Gas. However, the Company's revenue allocation proposal for Rate DS was designed to try to make the harmonization of the rates within that class somewhat less painful to those customers in the northern operating district. As I explain below, while the Company should continue to make progress toward harmonizing rates, full harmonization in this proceeding is not yet reasonable.

Q. Do you have recommendations in the event the Commission awards UGI Gas with an increase below the $82.74 million requested?

A. In order to retain the parameters that I use in my revenue allocation, a proportional scaleback approach is not unreasonable. Thus, for example, if the allowed increase is set at $35 million (a little better for the Company than the average of the last three cases), the increase for the residential class would be $71.45 million * $35 million / 82.74 million = $30.22 million, or 8.0 percent. The XD and IS class rate changes would remain at zero. The progress toward cost-based rates for the N/NT, DS and LFD classes would necessarily be reduced, but that effect is unavoidable without assigning an increase to the R/RT class that is more than 1.5 times system average.

4. Rate Design

Q. Please summarize the Company's proposal to harmonize the base rates tariff for Rates N/NT and DS in this proceeding.

A. Prior to 2018, UGI Utilities, Inc. had one operating division that was a regulated gas utility and two subsidiary gas utilities, namely UGI Central Penn Gas and UGI Penn Natural Gas. At Docket Nos. A-2018-300381/2/3, the Commission approved the merger of these three entities into the UGI Utilities, Inc. (Gas Division), although separate regulations and tariffs continued to apply to each of t three "rate districts" (denoted South, Central, and North respectively). However, for several years prior to the merger, the Company had substantially harmonized the rate class definitions and eligibility rules for the three entities. In the Company's last two base rates proceedings at Docket No. R-2018-3006814 and Docket No. R-2020-3015162, the Company proposed to fully harmonize the tariffs for the three rate districts, both with respect to the purchased gas cost ("PGC") rate charged to utility gas sales customers and the base rates tariff charges for distribution and related services.

In both of those proceedings, I objected to the full harmonization for base rates, due to the rate shock implications.[18] These effects would have been unreasonable and excessive for the Rate N/NT customers and especially Rate DS customers in the North rate district. The settlement in the former proceeding provided for full harmonization of the PGC rate, and it harmonized base rates for the South and Central districts. However, it retained base rate differentiations between the North rate district and the South/ Central rate districts, for Rate N/NT and Rate DS. The settlement of that first case explicitly recognized that the

[18] OSBA Statement No. 1, Docket No. R-2018-3006814, pages 27-30. OSBA Statement No. 1, Docket No. R-2020-3015162, pages 38-41.

Company could propose full harmonization in its next base rates case, and that parties could oppose such a proposal.[19] In the most recent base rate case, the settlement indicates that the Company's proposal to harmonize the rates was withdrawn without prejudice, with the provision that "[t]he Company may propose this in the Company's next base rate case, but no sooner than January 1, 2022."

In this proceeding, the Company again proposes to fully harmonize the base distribution rates for Rate N/NT and Rate DS. UGI Gas witness Sherry A. Epler concludes that this proposal does not violate the traditional bounds for rate shock because the proposed increases for the North district customers in those classes are less than twice the system average increase.[20]

Q. What is the Company's specific proposal for base rates tariff charges for Rate N/NT and Rate DS in this proceeding?

A. Table RDK-5 below shows the proposed changes in tariff charges, as well as the bill implications for the average customer.

[19] The Settlement states, "For Step 1, the Rate N/NT North rate district rates will be increased by twelve (12) percent and Rate DS North rate district rates will be increased by twenty (20) percent, with Rate N/NT and Rate DS South and Central rate districts being set uniformly by class to recover the remaining N/NT and DS revenue requirements, respectively. For Step 2, the parties reserve their rights to oppose the Company's proposed rates and propose alternative rates."

[20] UGI Gas Statement No. 1 at page 19, footnote 1. Witness Epler's upper limit of two times system average appears to only apply to small business customers. For revenue allocation in this proceeding, the Company proposes to assign an increase of approximately 1.5 times the system average to the residential class, leaving that class still falling well short of a system average rate of return. Similarly, Witness Epler complains that North district Rate DS customers have been under-paying their cost of service for a three-year period. However, Witness Epler's concerns in this respect do not appear to apply to the R/RT class, where revenues have fallen short of allocated costs for decades.

Table RDK-5 UGI Gas Rate Design Proposal: Rate N/NT and Rate DS						
	Rate N/NT			Rate DS		
	Current Rates	Proposed Rates	Percent	Current Rates	Proposed Rates	Percent
Customer Charge ($/mo.)	23.50	30.00	27.7%	260.00	260.00	0.0%
Distribution Charge ($/mcf) South/Central	3.6271	4.0413	11.4%	2.9730	2.9977	0.8%
Distribution Charge ($/mcf) North	3.2653	4.0413	23.8%	2.1335	2.9977	39.3%
Typical Bill ($/Year) South/Central	$1,986	$2,153	8.4%	$24,832	$23,821	-4.1%
Typical Bill ($/Year) North	$1,817	$2,153	18.5%	$18,876	$23,821	26.2%

Notes:

1. The base rate tariff charges under current rates exclude the DSIC, which would be at 5.0 percent without a base rate increase.
2. The typical bill is based on customer and distribution charges inclusive of DSIC, excluding PGC and other charges for specific functions.

Sources: RDK WP1.

With this proposal for Rate N/NT, the Company proposes an overall average increase of a little over 10 percent, but the increase for the North district customers is some 2.1 times the increase for the South/Central rate district. For Rate DS, the typical increase for a North district customer would exceed 26 percent, while other customers in the class would see a material rate decrease.

I respectfully submit that imposing a 26 percent rate increase on one group of customers in this proceeding is not reasonable.

Q. What of the Company's argument that the Rate DS increase is within two times the system average?

A. Even if it were reasonable to accept an upper bound of two-times system average, the Company's argument quickly falls apart when the reality of a credible rate increase intrudes. As parties are aware, the actual rate increase award in a Pennsylvania base rates proceeding, either as a result of settlement or Commission decision, is almost always materially lower than the filed increase. Given the specific context of the current case, I deem it likely that any awarded rate increase will be significantly lower than the $82.7 million claimed. Based on the history of the past three proceedings shown in Table RDK-1 above, the awarded increase may very well be below $35 million (5.3 percent).

However, fully harmonizing the rates in a single rate proceeding will require rate increases to the North district customers that are nearly as large as those proposed in the filing, particularly for the Rate DS class. That is, the relative impact of harmonizing the rates on the North district customers does not get fully scaled back with a reduction in the overall rate increase.

For example, suppose the overall rate increase was reduced to $35 million, or about 5.3 percent, and the increases for Rates N/NT and DS were scaled back proportionately from the Company's proposed revenue allocation. I calculate that full harmonization of the Rate N/NT rates would require increases for North district customers of about 12.8 percent (which would be 2.4 times system average) and harmonization of the Rate DS rates would require an increase of 25.8 percent (4.8 times the system average). The basic arithmetic fact is that harmonizing Rate DS, and to a less extent Rate N/NT, will require a very large rate increase for North district customers, regardless of the level of the overall utility increase.[21]

Q. What do you recommend for this proceeding?

A. I recommend that the increase for North district customers be limited to no more than 1.5 times the system average increase, which would be 18.9 percent at the Company's full proposed increase. Similarly, I propose that the increase for both groups of customers within the N/NT and DS classes be proportionately scaled back for any reduction in the Company's claimed rate increase. Thus, if the overall increase is reduced from $82.7 to

[21] In theory, this increase could be mitigated by providing a substantial decrease to Rate DS overall. I deem such an outcome to be highly improbable, based on experience.

$35.0 million, the increase for North district customers would be limited to an increase of $35.0/$82.7 * 18.9% or 8.0 percent.

A detailed proof of revenues for rates at the Company's full proposed revenue requirement with my revenue allocation and these recommendations is included in RDK WP2. The specific tariff charges are shown in Table RDK-6 at the end of this testimony.

Note that my recommendation in this respect applies to any approved revenue allocation, for both the N/NT and DS rate classes. However, as shown in RDK WP2, at my proposed revenue allocation with the reduced assignment to Rate N/NT (before the effects of any scaleback), this limit would allow for full harmonization of the N/NT rates. The Rate DS volumetric charges would continue to be differentiated, even with the typical North district customer being assigned an 18.9 percent increase, while other DS customers would see an increase of less than 1.0 percent.

Q. Please address the issue of the customer charge for Rate N/NT.

A. As shown in Table RDK-5 above, the Company proposes to assign a nearly 28 percent increase to the Rate N/NT customer charge, compared to an overall class average increase of about 10 percent. Because the customer charge for the rate districts has already been harmonized, this proposal is not intertwined with the issue of harmonizing the North district rates. Nevertheless, this proposal will materially shift the nature of cost recovery in the Rate N/NT class, it and will result in a substantial rate increase for smaller customers within the class. For example, for small businesses with loads that are similar to an average residence, the Company's rate design proposal will result in an increase of 13.5 percent for South and Central district customers, and a nearly 20 percent increase for North district customers.

Q. How should the results from the CSAS be used to inform setting the customer charge for the Rate N/NT class?

A. The simplest approach would be to sum the costs classified to "customer-related" in the CSAS, and divide by the number of monthly bills. The problem with that approach is that, unlike the residential class, the Rate N/NT class includes customers with a wide array of sizes and costs to serve. Larger customers within the customer class require larger meters and more costly service lines. Thus, if a single customer charge applies to all customers in the class, using the average cost method will simply mean that small customers are inequitably subsidizing larger customers. For this reason, some Pennsylvania NGDCs have adopted differentiated customer charges for general service customers. UGI Gas has not made such a proposal in this proceeding.

Thus, in the UGI Gas single customer charge framework, the correct cost basis for the customer charge should be the customer related cost to service the smaller customers within the class, leaving the volumetric charge to absorb the costs for the more expensive meters used by the larger customers. While the cost for a small Rate N/NT customer is not directly available from the CSAS, the customer-related cost for a residential customer is. Since small Rate N/NT customers can be similar in size to a residential customer, this approach results in a reasonable proxy.

Using my CSAS simulation at the UGI Gas proposed rates, the full customer component of residential class costs is about $33 per customer per month. As such, the Company's $30 proposed customer charge is near the upper bound of the cost range for small Rate N/NT customers.

Q. How does the Company's proposal compare to the customer charge used by other Pennsylvania NGDCs for smaller non-residential customers?

A. The $30 charge would be at the upper end of the range, but not outside it. Table RDK-6 below shows the monthly customer charge for small non-residential customers.

Table RDK-6 Non-Residential Customer Charges: Pennsylvania NGDCs	
	$/month
National Fuel Gas Dist'n C&PA (< 250 mcf)	$19.89
Peoples Natural Gas SGS (< 500 mcf)	$20.00
UGI Gas N/NT (current)	$23.50
Philadelphia Gas Works GS-C	$25.35
PECO Gas GC*	$28.55
Columbia Gas SGSS/SCD/SGDS**	$29.92
UGI Gas N/NT (proposed)	$30.00
Peoples Gas (TWP) SGS (<500 mcf)	$35.00

* PECO proposes a $38.82 customer charge in its current base rates proceeding.

** Columbia proposes a $34.23 customer charge in its current base rates proceeding.

Note: Customer charges exclude the effects of DSIC, TCJA or other multipliers.

Sources: Company websites

Q. With that background, what do you recommend?

A. Because the Company's proposal is justified on a cost basis at its proposed rates, I do not object to the $30 charge if the full increase were to be granted. However, to mitigate the rate shock for small customers, the increase should be scaled back with any overall reduction in the Company's proposed revenue requirement. Thus, for example, if the Company's allowed increase is $35.0 million rather than $82.7 million, the customer charge increase would be scaled back; i.e., $23.50 + $6.50 * $35.0/$82.7 = $26.25 per month.

Q. In light of your recommendations for revenue allocation, rate harmonization and the Rate N/NT customer charge, what is your recommended rate design for Rates N/NT and DS?

A. Table RDK-7 below provides my recommendation. Detailed supporting calculations are provided in RDK WP2.

Table RDK-7 RDK Rate Design Proposal: Rate N/NT and DS at Full Revenue Requirement						
	RDK Rate N/NT			**RDK Rate DS**		
	Current Rate	**Proposed Rate**	**Percent**	**Current Rate**	**Proposed Rate**	**Percent**
Customer Charge ($/mo.)	23.50	30.00	27.7%	260.00	260.00	0.0%
Distribution Charge ($/mcf) South/Central	3.6271	3.8673	6.6%	2.9730	3.1668	6.5%
Distribution Charge ($/mcf) North	3.2653	3.8673	18.4%	2.1335	2.7992	30.1%
Typical Bill ($/Year) South/Central	$1,986	$2,076	4.5%	$24,832	$24,989	0.6%
Typical Bill ($/Year) North	$1,817	$2,076	14.2%	$18,876	$22,450	18.9%

Notes:
1. The base rate tariff charges under current rates exclude the DSIC, which would be at 5.0 percent without a base rate increase.
2. The typical bill is based on customer and distribution charges inclusive of DSIC, excluding PGC and other charges for specific functions.Sources: RDK WP2.

Q. Please state OSBA's position with respect to the Company's proposed weather normalization adjustment ("WNA") mechanism.

A. The Company proposes to implement a WNA for its R/RT and N/NT classes. The mechanism would adjust customer bills in all months between October and May for the difference between actual heating degree days ("HDDs") and the normal HDDs used to develop base rates. The adjustments would occur in "real time," in that each bill would reflect both the actual and normal HDDs for the particular period that applied to that bill. The Company's mechanism would reflect a customer-specific parameter for the "base" non-heating load (based on a three-year history of summer use), and it would adjust the actual use in excess of that base amount for the ratio of normal to actual HDDs. The adjusted actual use would then serve as the volumetric billing determinant. As proposed, the WNA mechanism would not be a pilot program, and it would include no "dead band" within which no adjustments are made.

I am advised by counsel that OSBA intends to contest this proposal as not just and reasonable on the grounds that the substantial risk reduction benefits to the Company and the rate instability implications for customers associated with this mechanism are not reasonably reflected in the allowed return on capital claim in this proceeding.

Q. What is the OSBA's concern regarding the Company's cost claim related to the BTU heat content rate adjustment mechanism?

A. At Docket No. R-2021-3026078, the Company proposed, and the Commission approved, a rate mechanism designed to facilitate the incorporation of renewable gas supplies with below-average BTU content into the Company's gas distribution mix. In effect, the tariff was modified to be able to reflect geographic differences in gas energy content such that customers would all pay the same per unit of energy delivered. In its filed tariff supplement at that docket, the Company indicated, "The proposed change is intended to assure there is no impact to the utility's revenue and expenses." In this proceeding, the Company reports that it is claiming approximately $2.0 million in information system rate base associated with the adoption of this rate mechanism.[22] I am advised by counsel that based on the evidence available at this time, OSBA intends to contest this claim.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[22] See OCA-I-39, OSBA-I-16.

EXHIBIT RDK-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

Overview

Mr. Knecht has more than 40 years of economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 30 years, Mr. Knecht's practice has primarily involved providing analysis, consulting support and expert testimony in regulatory matters, primarily involving electric and natural gas utilities. Mr. Knecht's work includes many aspects of utility regulation, including industry restructuring, cost unbundling, cost allocation, rate design, rate of return, customer contributions, energy efficiency programs, smart metering programs, treatment of stranded costs and utility revenue requirement issues. He has consulted to state advocacy agencies, industrial customer groups, law firms, regulatory agencies, government agencies and utilities, in both the United States and Canada. He has provided expert testimony in more than one hundred separate utility proceedings.

In addition to his work with regulated utilities, Mr. Knecht has consulted on international industry restructuring studies, prepared economic policy analyses, participated in a variety of litigation matters involving economic damages, and developed energy industry forecasting models.

Mr. Knecht served as a Principal of IEc for 33 years, and as its Treasurer for 15 years. He is currently an independent consultant who remains affiliated with IEc.

Education

Master of Science, Management (Applied Economics and Finance), Sloan School of Management, M.I.T.

Bachelor of Science, Economics, Massachusetts Institute of Technology

Select Project Experience

For more than 25 years, Mr. Knecht has provided consulting services, analysis and expert testimony before the Pennsylvania Public Utility Commission on all manner of regulatory proceedings to the **Pennsylvania Office of Small Business Advocate**. In addition to expert testimony, Mr. Knecht has assisted OSBA with the development of public policy positions, litigation strategy, and longer term strategy.

For the **Attorney General of the State of Rhode Island**, Mr. Knecht provided consulting and expert witness services in an acquisition proceeding involving PPL Corporation's proposed acquisition of Narragansett Electric from National Grid. Mr. Knecht's testimony addressed financial, economic, environmental, tax, operating cost and rate implications.

For the **New Brunswick Public Intervener,** Mr. Knecht provides consulting and expert witness services in a variety of regulatory proceeding before the New Brunswick Energy and Utilities Board involving New Brunswick Power, Enbridge Gas New Brunswick, and petroleum products. Mr. Knecht has addressed issues of load forecasting, costs forecasting, cost of capital, allocation of corporate overhead costs, utility cost allocation, revenue allocation, market-based rate design, cost-based rate design, and rate decoupling.

For **l'Association québécoise des consommateurs industriels d'électricité (AQCIE) and le Conseil de l'industrie forestière du Québec (CIFQ)**, Mr. Knecht provided analysis, consulting advice and expert testimony before the Régie de l'énergie in regulatory matters involving Hydro Québec Distribution and TransÉnergie. This work includes revenue requirement, power purchasing, cost allocation, treatment of cross-subsidies, and rate design.

For the **Independent Power Producers Society of Alberta**, Mr. Knecht provided consulting advice, analysis and expert testimony before the Alberta Energy and Utilities Board in a series of proceedings involving the restructuring of the electric utility industry, the unbundling of rates, and the development of transmission rates.

EXHIBIT RDK-2

REFERENCED INTERROGATORY RESPONSES

OSBA-I-3

OSBA-I-4

OSBA-I-16

OSBA-I-18

OCA-I-39

These interrogatory responses and attachments are available on the Post & Schell Sharepoint site subject to confidentiality constraints and are incorporated by reference. OSBA will take the necessary steps to enter these responses into the record at the appropriate time.

EXHIBIT RDK-3

ELECTRONIC WORKPAPERS

RDK WP1: Replication of UGI Gas CSAS

RDK WP2: RDK Alternative CSAS

RDK WP3: Design Day Demand Workpapers

*** Electronic workpapers will be delivered by email simultaneous to service of Direct Testimony***

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3030218**
UGI UTILITIES, INC. (Gas Division)	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits RDK-1 through RDK-3 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: April 20, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI Utilities, Inc. – Gas Division	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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/s/ Steven C. Gray

DATE: April 20, 2022

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

May 17, 2022

Administrative Law Judge Joel H. Cheskis
Administrative Law Judge Gail Chiodo
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Gas Division / Docket No. R-2021-3030218

Dear Judge Cheskis and Judge Chiodo:

Enclosed please find the Rebuttal Testimony and Exhibit of Robert D. Knecht, labeled OSBA Statement No. 1-R, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3030218**
UGI UTILITIES, INC. (Gas Division)	:	

Rebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: May 17, 2022

Date Submitted for the Record: ___________________________

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony and associated exhibits earlier in this proceeding, and my qualifications were presented therein.

Q. What is the purpose of this rebuttal testimony?

A. This rebuttal testimony responds briefly to the cost allocation and revenue allocation recommendations of Office of Consumer Advocate ("OCA") Witness Jerome D. Mierzwa.

Q. Please summarize the changes proposed by Witness Mierzwa for the Company's cost of service allocation study ("CSAS").

A. Witness Mierzwa recommends that the Company's modified average-and-excess ("A&E") method for classifying and allocating mains costs be replaced with a 50/50 weighted peak-and-average ("P&A") methodology. Witness Mierzwa also recommends making four technical adjustments to the CSAS.

I note also that Witness Mierzwa accepted the Company's methodology for deriving the class design day demands that are used in both the A&E and P&A allocation factors. As such, I do not believe that Witness Mierzwa's CSAS is reasonable, because it relies on unreasonable estimates for the design day demands of the R/RT and N/NT rate classes.

Q. Please restate your view of the P&A methodology for classifying and allocating mains costs.

A. As I explained in my direct testimony, none of the standard methods for classifying and allocating mains costs are consistent with cost causation, and none are reasonable in this era where detailed system modelling techniques are available. The P&A method is particularly problematic, in that it relies heavily on average demand. Mains costs are not causally related to average demand. Mains are designed to meet design day demand, and to interconnect customers. However, as I also explained in direct testimony, the Company has not offered a detailed modelling approach (since 1996), and the Commission has recently accepted both the A&E method (for PECO Gas) and the P&A method (for

Columbia Gas). As the Commission has provided little guidance as to why it accepted the A&E method in PECO Gas after approving the P&A method in Columbia Gas, it is difficult to evaluate whether the Company's method or Witness Mierzwa's method is more consistent with Commission precedent. As I noted, the PECO Gas decision (using the A&E method) may be more relevant, since it involved a head-to-head comparison of the A&E and P&A methods, whereas the A&E method was not directly before the Commission in the Columbia Gas matter.

Q. Witness Mierzwa indicates that ". . . Ms. Heppenstall's Mains allocation factors are nearly identical to the results obtained when average demand allocation factors are weighted at zero, and pure peak allocation factors are weighted at 100 percent." Do you agree?

A. Not completely. As I explained in my direct testimony, I agree with Witness Mierzwa that the traditional load-factor weighted A&E method will arithmetically default to a pure peak demand allocator if there is no diversity in demand. However, the Company does not rely on the actual system load factor for weighting the average component of costs in its A&E allocator, but in fact uses an alternative weighting factor that increases the weight assigned to average demand. Its method therefore produces an allocator that is 79 percent based on peak demand and 21 percent based on average demand.[1] As such, the Company's method lies between a traditional A&E approach and Witness Mierzwa's recommended P&A method.

Q. What do you conclude from Witness Mierzwa's views on mains cost classification and allocation?

A. I acknowledge that Witness Mierzwa's method is consistent with that approved by the Commission for Columbia Gas. However, I conclude that the Company's method is also reasonably consistent with the Commission's decision in PECO Gas (wherein the P&A method was rejected), the Company's method has a reduced reliance on average demand which is not a contributor to mains cost causation, and the Company's method represents

[1] These values are derived in RDK WP1 in the "Allocs" worksheet at cells B119:K127.

a compromise between a traditional A&E method and Witness Mierzwa's P&A method. I therefore continue to rely on the Company's modified A&E method in this proceeding.

Q. What technical changes does Witness Mierzwa propose for the CSAS?

A. Witness Mierzwa proposes the following changes:

- Manufactured gas plant remediation costs included in accounts 740-742 should be allocated in proportion to overall O&M expense, consistent with the treatment of those costs for Accounts 930 and 932;

- Forfeited discounts should be allocated based on actual historical forfeited discounts, rather than penalty revenues;

- Reconnection fees should be allocated based on actual reconnection fees, rather than the overall revenue requirement;

- The Company's acknowledged error for sub-functionalizing costs in Account 874 should be incorporated into the CSAS.

Q. Do you agree with these recommendations?

A. With the exception of Witness Mierzwa's proposed change to reconnection fees, I do.

Regarding reconnection fees, these charges are imposed to recover the costs associated with reconnections. Therefore, the revenues are an offset to those costs, and should be allocated in the same manner. Thus, if the Company were to allocate the *costs* incurred for reconnections based on actual reconnections, Witness Mierzwa's approach for the reconnection *fees* would be reasonable. However, the Company does not separately allocate the costs for reconnections, and it implicitly uses an aggregate O&M allocator for those costs. As such, it is not appropriate to allocate reconnection fees based on actual history, but rather based on aggregate O&M costs. In effect, reconnection costs and reconnection fees should both be allocated on the same basis.

Q. Have you replicated Witness Mierzwa's CSAS, using your cost allocation model?

A. I have. It is attached as RDK WPR1.

Q. Will you reflect the changes proposed by Witness Mierzwa with which you agree in your CSAS?

A. I will. I intend to update my CSAS in surrebuttal testimony to address any changes that result from the Company's rebuttal filing, as well as to incorporate the three technical changes offered by Witness Mierzwa with which I agree. I will similarly update my revenue allocation and rate design recommendations, as necessary.

Q. What is Witness Mierzwa's revenue allocation recommendation?

A. Witness Mierzwa's revenue allocation is summarized in Table RDK-R1 below. Because the Company's indexed rate of return metric cannot reasonably be used to measure progress toward cost-based rates, I rely on the normalized revenue-cost ratio method. The column labeled "progress" represents how much the proposed revenue allocation moves the revenue-cost ratio toward 100%. So, for example, the R/RT revenue cost ratio moves 3.4 percentage points from 91.9% to 95.3%, out of the 8.1 percentage points needed to move from 91.9% to 100.0%, a ratio of 3.4/8.1 = 42%.

Table RDK-R1
OCA Revenue Allocation Proposal Using
OCA Cost of Service Allocation Study

	Increase $mm	**Increase %**	**R-C Ratio Current Rates***	**R-C Ratio Proposed Rates***	**Progress**
R/RT	$60.28	16.0%	91.9%	95.3%	42%
N/NT	$12.98	9.3%	114.5%	109.3%	36%
DS	$2.13	6.3%	115.2%	108.7%	43%
LFD	$5.65	12.6%	101.6%	100.1%	96%
XD-Firm	--	0.0%	133.3%	120.5%	38%
IS/XD-I	$1.70	7.1%	107.2%	100.0%	100%
Total	**$82.74**	**12.6%**	**100.0%**	**100.0%**	**--**

* Based on OCA proposed CSAS methodology, replicated in RDK WPR1.
Source: RDK WPR1

Q. Is Witness Mierzwa's proposed revenue allocation consistent with the OCA proposed CSAS?

A. Witness Mierzwa's revenue allocation proposal is *directionally* consistent with the OCA CSAS, but it appears to elevate the criterion of rate gradualism above the criterial of moving rates into line with allocated cost. In Pennsylvania, the Commonwealth Court has determined that cost is the "polestar" criterion for revenue allocation. Moreover, in terms of equity, the R/RT class has been generating revenues that fall well short of allocated costs, since at least 1996. Small and medium-sized businesses in the N/NT and DS classes have been paying for that shortfall for a similar period. Despite those considerations, Witness Mierzwa proposes an increase for the R/RT class that is only 1.27 times the system average increase, when the traditional rule of thumb for rate gradualism is to limit the increase to 1.5 or 2.0 times system average. As such, I conclude that even if the OCA CSAS methodology were adopted, Witness Mierzwa's proposed revenue allocation is not reasonable as it simply perpetuates a long-standing historical inequity.

Q. If Witness Mierzwa's CSAS is adopted, what revenue allocation would you propose?

A. Under the OCA CSAS, my recommendation is shown in Table RDK-R2 below. In developing this recommendation, I accept Witness Mierzwa's proposals for the LFD and IS/XD-I classes, because his proposals move those classes fully into line with the OCA's allocated cost. Consistent with my direct testimony, I assign a 1.5 times system average increase to the R/RT class, which still fails to bring revenues into line with allocated cost.[2] The balance of the increase is assigned to the N/NT and DS classes, so as to balance the revenue-cost ratio for those classes at proposed rates. As shown, my revenue allocation under the OCA CSAS results in considerably more progress toward cost-based rates than that offered by Witness Mierzwa. For example, this revenue allocation moves the revenue-cost ratio for the residential class from 91.9 percent to 97.7 percent, thereby making progress toward cost-based rates of 71 percent.

[2] The OCA has supported the use of these parameters in other proceedings. See, for example, OCA Statement No. 4 at page 26 at Docket No. R-2020-3018929 (the PECO Gas matter in which the Commission approved the A&E method), wherein OCA applies both the 1.5X and 2.0X increases.

Table RDK-R2 RDK Revenue Allocation Proposal Using OCA Cost of Service Allocation Study					
	Increase $mm	**Increase %**	**R-C Ratio Current Rates***	**R-C Ratio Proposed Rates***	**Progress**
R/RT	$71.45	18.9%	91.9%	97.7%	71%
N/NT	$3.79	2.7%	114.5%	102.8%	81%
DS	$0.15	0.4%	115.2%	102.8%	81%
LFD	$5.65	12.6%	101.6%	100.1%	96%
XD-Firm	--	0.0%	133.3%	120.5%	38%
IS/XD-I	$1.70	7.1%	107.2%	100.0%	100%
Total	**$82.74**	**12.6%**	**100.0%**	**100.0%**	**--**

* Based on OCA proposed CSAS methodology, replicated in RDK WPR1.
Source: RDK WPR1

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT RDK-R1

ELECTRONIC WORKPAPERS

RDK WPR1: Replication of OCA CSAS

UGI Gas Utilities Inc., Gas Division (UGI Gas)

RDK Workpaper #R1: Cost of Service Allocation Study YE 30 September 2023; Replication of OCA P&A Methodology

Summary at Proposed Rates: OCA Revenue Allocation

Valid if "Proposed" ==> Proposed

	Total	R/RT	N/NT	DS	LFD	XD-Firm	IS	XDI
Rate Revenues	738,286,414	437,650,632	151,804,131	35,906,433	50,514,565	36,697,801	25,712,853	0
Other Revenues	10,286,321	6,226,356	2,574,653	422,270	529,645	308,842	224,555	0
Total Revenues	**748,572,735**	**443,876,988**	**154,378,783**	**36,328,703**	**51,044,210**	**37,006,643**	**25,937,408**	**0**
O&M Expense	293,485,866	196,203,254	43,995,512	12,996,950	17,312,367	14,623,036	8,354,748	0
Depreciation Expense	125,531,905	78,912,303	25,666,999	5,031,238	7,932,516	3,880,641	4,108,208	0
Other Taxes	13,657,627	8,390,788	2,536,181	672,347	927,069	659,575	471,667	0
Interest Expense (RB Rd.)	56,726,000	32,805,827	12,407,133	2,641,490	4,460,444	2,075,213	2,335,893	0
Pre-Tax Expenses	**489,401,398**	**316,312,171**	**84,605,826**	**21,342,024**	**30,632,396**	**21,238,465**	**15,270,515**	**0**
Pre-Tax Income	**259,171,337**	**127,564,817**	**69,772,958**	**14,986,679**	**20,411,814**	**15,768,178**	**10,666,893**	**0**
Income Tax (PTI, Rd)	63,347,000	31,179,393	17,053,012	3,661,457	4,985,409	3,851,498	2,609,896	0
Total Return	**252,550,337**	**129,191,251**	**65,127,078**	**13,966,712**	**19,886,849**	**13,991,893**	**10,392,889**	**0**
Rate Base	**3,169,006,045**	**1,832,702,207**	**693,126,249**	**147,567,195**	**249,183,346**	**115,932,067**	**130,494,981**	**0**
Rate of Return	**7.97%**	**7.05%**	**9.40%**	**9.46%**	**7.98%**	**12.07%**	**7.96%**	**#DIV/0!**
Total Cost of Service	**748,245,483**	**465,955,655**	**141,220,772**	**33,407,571**	**51,009,802**	**30,714,272**	**25,937,410**	**0**
Revenue/Cost Ratio	**100.0%**	**95.3%**	**109.3%**	**108.7%**	**100.1%**	**120.5%**	**100.0%**	**#DIV/0!**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3030218**
UGI UTILITIES, INC. (Gas Division)	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Rebuttal Testimony labelled OSBA Statement No. 1-R and associated Exhibit RDK-R1 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: May 17, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI Utilities, Inc. – Gas Division	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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/s/ Steven C. Gray

DATE: May 17, 2022

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

May 27, 2022

Administrative Law Judge Joel H. Cheskis
Administrative Law Judge Gail Chiodo
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Gas Division / Docket No. R-2021-3030218

Dear Judge Cheskis and Judge Chiodo:

Enclosed please find the Surrebuttal Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1-S, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

Office of Small Business Advocate
Forum Place 1555 Walnut Street, 1st Floor | Harrisburg, PA 171011717.783.2525 | Fax 717.783.2831 | www.osba.pa.gov

OSBA Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3030218**
UGI UTILITIES, INC. (Gas Division)	:	

Surrebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: May 27, 2022

Date Submitted for the Record: ____________________________

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. Introduction

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony, rebuttal testimony and associated exhibits earlier in this proceeding, and my qualifications were presented therein.

Q. What is the purpose of this surrebuttal testimony?

A. This testimony responds to the rebuttal testimony of various UGI Utilities Inc. – Gas Division ("UGI Gas" or "the Company") witnesses, specifically:

- On cost allocation matters, Witness Constance E. Heppenstall;
- On revenue allocation matters, Witnesses Christopher R. Brown and Sherry A. Epler;
- On the issue of "harmonizing" Rates N/NT and DS, Witness Epler;
- On the Company's proposed weather normalization adjustment ("WNA") mechanism, Witness John D. Taylor.

I note that Pennsylvania Office of Consumer Advocate Witness Jerome D. Mierzwa submitted rebuttal testimony regarding cost allocation matters. However, my rebuttal testimony addresses the relevant methodological issues, and it provides my recommendation for revenue allocation in the event Witness Mierzwa's cost allocation method is adopted. As such, there is no need to respond further in this testimony.

The four topics are addressed sequentially below.

2. <u>Cost Allocation</u>

Q. Did the Company update its cost of service allocation study ("CSAS") in rebuttal testimony to reflect the parties' filings?

A. Yes, or at least it attempted to do so.[1] The Company submitted a summary of its revised CSAS in Exhibit D-R, and it made its electronic workpapers available to intervenors. The Company made the following changes to the CSAS from the filed version:

- In response to my direct testimony, the Company modified the design day demand allocators for the R/RT and N/NT classes to reflect the historical weather sensitivity analysis that I presented;
- In response to Witness Mierzwa's direct testimony, the Company modified the allocation of certain environmental O&M costs related to long-shuttered manufactured gas facilities so as to assign those costs only to gas sales customers and to exempt all transportation customers from any responsibility for those costs;
- Consistent with its own response to an interrogatory and Witness Mierzwa's direct testimony, the Company modified its sub-functionalization of O&M operating costs in Account 874 for meters/services between costs related to meters and costs related to services;
- In response to Witness Mierzwa's direct testimony, the Company modified its allocation of certain "other" revenues to reflect actual historical revenue patterns.

Q. Do you agree with the Company's adjustments to the design day demand allocator?

A. I do. The design day demand factor in the Company's revised CSAS in Exhibit D-R is now consistent with my recommendation.

Q. Do you agree with the Company's adjustment to O&M costs related to manufactured gas facilities?

[1] In addition to the errors detailed herein, the Company continues its practice of aggressively rounding its allocation factors to no apparent purpose. In its rebuttal CSAS under present rates, at least four of the allocation factors fail to total to 100 percent (Factors 12, 13, 14, and 15). This practice is mostly harmless, but it can result in needless distortions for rate classes with relatively low cost to serve. I eliminate this rounding in RDK WPS1.

A. No.[2] The Company claims that these costs are related to gas supply, and thus should be borne only by sales customers. The Company's argument is akin to claiming that the costs of cleaning up a buggy whip factory are causally related only to customers who now buy automobiles. The costs in question were incurred in a different era and under a different regulatory regime, notably one in which shopping for gas supplies was not permitted and all customers benefited from manufactured gas facilities. That gas utilities are allowed to recover the costs for these facilities at all, which are not "used and useful," suggests that these costs are more akin to an environmental tax than a typical utility cost of service. Moreover, it is likely that few if any of UGI Gas's current customers benefited from the manufactured gas plants which give rise to these costs.

As such, these costs are better allocated broadly across all customers, rather than assigning them only on the basis of gas sales volume. Thus, as I indicated in my rebuttal testimony, I agree with Witness Mierzwa's proposal to consistently allocate these costs across all rate classes, using the O&M expense allocator (Factor 12).

Moreover, if the Commission approves the assignment of these costs in the manner proposed by the Company, it will become necessary to establish separate rates for sales (Rates R and N) and retail transportation (Rate RT and NT). Under the Company's logic, if the manufactured gas plant costs are assigned only to utility sales customers, the retail transportation customers in Rates RT and NT have no responsibility for the costs in question and thus should pay lower rates.

Q. Do you agree with the Company's proposal to modify the sub-functionalization of Account 874 meters/services operating costs?

A. I agree with that proposal because the Company indicated that its original filing was erroneous and inconsistent with the workpaper provided in response to discovery. As a practical matter, however, implementing this modification is proving to be problematic. In developing the OCA CSAS, Witness Mierzwa correctly modified the sub-functionalization

[2] As a technical matter, in modifying its allocation of certain manufactured gas O&M costs in Accounts 923 and 930, it failed to make a similar modification to the Labor O&M costs in those accounts. As I reject the Company's proposed method, there is no need for me to correct this error.

of Account 874 O&M costs, but the witness did not carry that calculation through to the Account 874 Labor O&M costs. Thus, the labor allocator in Witness Mierzwa's CSAS is based on an inaccurate sub-functionalization of the labor costs in Account 874.[3]

In the Company's rebuttal case in Exhibit D-R, the Company compounded the errors in Witness Mierzwa's CSAS. First, rather than modifying the sub-functionalization to be 55.1% mains and 44.9% services, the Company's calculation is reversed, and O&M costs are sub-functionalized as 44.9% to mains and 55.1% to services. (The Company subsequently corrected this error in response to informal OSBA discovery.) Second, like Witness Mierzwa, the Company fails to carry the change through to the Labor O&M cost allocation. (Although the Company indicated informally to OSBA that it intended to modify the labor allocator in the corrected version of the CSAS, the functionalization of labor costs for Account 874 in the revised CSAS is unchanged from the original filing.)[4]

Q. Do you agree with the Company's changes to the allocation of other operating revenues, as offered by Witness Mierzwa?

A. Yes and no. As I explained in my rebuttal testimony, Witness Mierzwa's proposal for forfeited discounts is reasonable, and the Company's revised CSAS adopts it. However, Witness Mierzwa's change in the allocation of reconnection revenues is not reasonable, because it should be allocated on the same basis as the cost for those reconnections, for the reasons laid out in my rebuttal. As such, I disagree with the Company's revised CSAS, as it adopts Witness Mierzwa's proposal.

Q. Have you developed a modified version of your proposed CSAS to reflect these changes?

A. I have, and it is attached in electronic form in RDK WPS1. Relative to the Company's original filing, it reflects:

---

[3] My RDK WPR1 CSAS follows Witness Mierzwa's method, because the object of my rebuttal analysis was to replicate the OCA CSAS and evaluate its implications for revenue allocation.

[4] See UGI Gas Exhibit D-R (Corrected) at page 21, where the Account 874 costs are split between mains and services at 51.9% mains, 48.1% services, unchanged form UGI Gas Exhibit D.

- Revised design day demand allocators;
- Allocation of all manufactured gas plant O&M costs using Factor 12;
- Sub-functionalization of both Account 874 O&M and Account 874 Labor O&M at 55.1% mains, 44.9% services;
- Allocation of forfeited discount revenues based on historical patterns.

Q. How does your revised CSAS compare to the Company's original filing and the CSAS in your direct testimony?

A. Table RDK-S1 below shows class rates of return at present rates under the four CSAS models.

Table RDK-S1
Comparison of Allocated Cost of Service Study Results
Class Rate of Return at Present Rates

	UGI Gas Filing	RDK Direct	OCA Direct	UGI Gas Rebuttal*	RDK Surrebuttal
R/RT	4.3%	4.1%	4.7%	4.1%	4.1%
N/NT	7.3%	8.1%	8.1%	7.9%	8.1%
DS	8.6%	8.6%	8.5%	8.7%	8.6%
LFD	9.4%	9.4%	6.4%	9.5%	9.4%
XD-Firm	14.0%	14.0%	12.3%	14.2%	13.9%
IS/XD-I	13.5%	13.5%	7.1%	13.5%	13.4%
Total	**6.1%**	**6.1%**	**6.1%**	**6.1%**	**6.1%**

* Partially corrected in response to OSBA informal discovery.
Source: RDK WP1, RDK WP2, RDK WPR1, UGI Gas Exhibit D-R, RDK WPS1

As shown in Table RDK-S1, all of the CSASs on file in this proceeding show that the residential R/RT classes produce revenues well below allocated cost, while all other classes produce revenues in excess of allocated cost. The only material difference for the non-residential classes is that the OCA "P&A" CSAS produces a class rate of return for the LFD class that is only slightly above system average, whereas the other "A&E" CSASs indicate that the LFD class rate of return is well above system average.

Table RDK-S1 also shows that the changes recommended by Witness Mierzwa which I incorporated into my surrebuttal testimony have almost no discernible impact on class rates of return compared to the results from the CSAS filed in my direct testimony.

3. Revenue Allocation

Q. What is the Company's position regarding your revenue allocation recommendations?

A. In my direct testimony, I explained why rate decreases should not be assigned to the XD and IS classes, that the increase for the R/RT class should be 1.5 times system average, and the balance of the increase should be used to allow for uniform progress toward cost-based rates for the N/NT, DS and LFD classes. Witness Brown presents the Company's view as to why rate reductions for the XD and IS classes are reasonable. Witness Epler addresses the issue of the maximum reasonable increase for the residential classes (R/RT).

Q. What are Witness Brown's arguments regarding the rate decreases?

A. Witness Brown makes two points. Initially, he argues that both the XD and IS classes exhibit class rates of return well above system average, and that the rate decreases are cost-justified. While I agree with Witness Brown's assessment of cost of service, I have three observations. First, Witness Brown clearly indicates that the XD and IS rates are market-based competitive rates.[5] As such, the cost of service criterion is less relevant for these rate classes than for other classes. Second, in my experience in Pennsylvania, I observe that it is unusual for the Commission to assign rate decreases to certain rate classes while other classes face large rate increases. Third, as shown in my workpapers, a zero rate increase for these classes will result in substantial progress toward cost-based rates.

Witness Brown makes a second point that the Company has been able to negotiate contracts with some XD and IS customers such that rates increase with the DSIC. Witness Brown argues that, with the DSIC reset from a base rates case, the contracts in place will necessarily result in a rate reduction from those customers. Witness Brown indicates that

[5] UGI Gas Statement No. 1-R at page 31 line 3, page 32 line 20, page 33 line 19, page 34 lines 9 and 22.

reopening those contracts to incorporate a provision to roll in the DSIC during a rate case would open the possibility that less favorable contracts would need to be negotiated.

Q. Is Witness Brown's argument regarding the contract provisions reasonable?

A. No. Consider the circumstances. These are customers who, according to the Company, have credible competitive alternatives to taking service from UGI Gas, presumably either an alternative fuel or bypass potential to interstate pipelines. In its negotiations with these customers, the Company determines that the competitive conditions are such that the customer can afford to experience rate increases associated with the DSIC. The Company then negotiates a contract in which the rates from these customers are allowed to increase with the DSIC, *only so long as those revenues flow to UGI Gas shareholders.* As long as the Company is between rate cases, the DSIC revenues flow to the shareholders. However, under the Company's negotiated contracts, as soon as new rates are imposed as a result of a base rates case, the DSIC is reset to zero, and the Company demands that the resulting revenue reduction get handed back to other ratepayers.

This approach is neither reasonable nor equitable. Negotiating a contract that is purportedly based on a customer's competitive alternatives, but which provides for an automatic rate reduction with the Company's next base rates proceeding, is unreasonable and borderline irresponsible. I recommend that the Commission not sanction this behavior by allowing the Company to force other ratepayers to pay for automatic rate decreases to competitive rates that have already been negotiated and accepted. Thus, for regulatory purposes, the allowed rate change for the XD and IS classes should be set to zero. If the Company both has the ability and chooses to re-open these contracts to negotiate more reasonable terms, it is free to do so at management's discretion.

Q. What is Witness Epler's position regarding revenue allocation to the R/RT classes?

A. Witness Epler's rebuttal states,

> "In addition, the Company continues to believe that an increase for the Rate R/RT customer class of 2.0 times the system average increase is appropriate, just, and reasonable. The Company has consistently utilized this standard in its rate cases as it does address the ratemaking principle of gradualism. An increase of 2.0 times the system average increase is further supported as appropriate for

> Rate R/RT in this case in order to move the only class demonstrating lower than system average returns closer to paying a system average rate of return; a demonstration of equity across all rate classes."[6]

I am puzzled by this rebuttal because (a) the Company did not propose a 2.0 times system average for the R/RT class in its filing, (b) I proposed a 1.5 times system average increase for the R/RT class in my direct testimony, and (c) the Company's rebuttal testimony continues to show revenue allocation for the R/RT class at 1.43 times system average, which produces a class rate of return at proposed rates that remains well below allocated cost.[7] Specifically, the system average increase is 12.62 percent, the Company's original and rebuttal proposed increase for R/RT is 18.05 percent (1.43 times system average), my proposed increase is 18.93 percent (1.50 times system average), and Witness Epler's rebuttal supports a 25.24 percent increase (2.00 times system average).[8]

In effect, Witness Epler appears to conclude that UGI Gas's own proposed allocation of the rate increase to the R/RT class is far too low, but the Company declines to change its revenue allocation to reflect Witness Epler's rebuttal testimony.

While a reasonable case could potentially be made to increase the R/RT increase to two times system average, I have not changed my recommendation for the R/RT class to reflect this apparent shift in the Company's position. As shown in my workpapers, the 1.5 times system average increase that I propose for Rate R/RT will result in material progress toward cost-based rates for all rate classes. However, I recommend that the Commission, when evaluating the various revenue allocation proposals in this case, recognize that the Company's rebuttal testimony supports a substantially larger increase for the R/RT class than that in my recommendation.

Q. Have you updated your revenue allocation analysis to reflect the changes to the CSAS?

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[6] UGI Gas Statement No. 8-R at 14.

[7] See Exhibit D-R Corrected, at Schedule A page 1 and Schedule B page 1.

[8] These values are based on tariff revenues excluding PGC costs, but including the MFC and GPC charges that apply only to sales service customers.

A. As detailed in the "SumProposed" worksheet of RDK WPS1, I developed an alternative revenue allocation based on the revised cost allocation analysis in that workpaper, using the same logic as that presented in my direct testimony. However, the differences between the surrebuttal revenue allocation analysis and that in my direct testimony are *de minimis*. As such, I retain the revenue allocation proposal in my direct testimony.

4. <u>Harmonizing Rates N/NT and DS</u>

Q. Why is there an issue regarding the harmonizing of Rates N/NT and Rate DS.

A. In 2008, UGI Utilities, Inc. ("UGIU") purchased PPL Gas Utilities Company from PPL Electric Utilities Corporation, and began operating it as UGI Central Penn Gas, Inc. ("CPG"). Also in 2008, UGIU purchased PG Energy Inc. from Southern Union Company, and began operating it as UGI Penn Natural Gas, Inc. ("PNG"). During the period in which these companies were operated and regulated as separate utilities, UGIU set rates based on the costs incurred for the individual utilities, but it undertook to harmonize rate class definitions, eligibility, and other tariff considerations across the UGIU family of gas utilities. In general, I supported UGI Gas's efforts in this respect, subject to rate gradualism and other rate design considerations.[9]

In 2018, the Commission approved a petition by UGIU et al. to merge UGI Gas, CPG and PNG into a single utility, at Docket Nos. A-2018-3000381/382/383, pursuant to a settlement among the parties (including OSBA).[10] In that proceeding, I submitted testimony that was generally supportive of the public benefits associated with the merger, but which recognized (and evaluated in some detail) the impacts on some customers if tariff rates were to be fully harmonized.[11] As detailed in that testimony, the primary negative impacts of the merger on rate harmonization would be for Rate N/NT and particularly for Rate DS customers in the PNG service territory. The settlement in that proceeding recognized that rates could not easily be harmonized, and that separate costing and rate design remained necessary for three operating areas: North (formerly PNG), Central

[9] See OSBA Statement No. 1, Docket No. R-2010-2214415; OSBA Statement No. 1, Docket No. R-2008-2079660.

[10] Joint Petition for Approval of Settlement of All Issues, Docket No s. A-2018-3000381/382/383, July 20, 2018.

[11] OSBA Statement No. 1, Docket No. A-2018-3000381 et al., at 8-13.

(formerly CPG) and South (formerly UGI Gas). Since that time, the Company has filed three base rates proceedings, it has moved away from separate costing within rate districts, and it has phased out rate differentials between the South and Central operating areas. In each proceeding, including the current one, the Company has proposed to apply rate increases far in excess of system average to North District (formerly PNG) N/NT and DS classes. While I have generally supported the Company's goal of eliminating separate costing regimes and gradually harmonizing rates, I have opposed the Company's efforts to impose rate increases on Rate N/NT and Rate DS customers that are many multiples of the system average increase, particularly when the effects of a rate scaleback are reflected.[12] It is simply not reasonable to impose enormous *relative* increases on a subset of small and medium business customers over a very short period of time simply because they had the misfortune to have their utility acquired by another utility with a higher cost structure.

Q. In your direct testimony, you recommended that the rate increase for Rate N/NT and DS customers in the former North operating area be limited to no more than 1.5 times the system average increase. How does the Company respond?

A. Witness Epler begins by stating that this is the third time the Company has attempted to harmonize the rates, and that not doing so will perpetuate an intra-class subsidy and that customers will not be treated equally. Witness Epler goes on to argue that if the Commission accepts that the principle of rate gradualism should apply to Rate N/NT and DS customers in the North district, the Commission should permit UGI Gas to increase the rates for North district customers by 2.0 times the system average in this proceeding, purportedly consistent with my recommendation for an upper limit in a recent Columbia Gas base rates proceeding.[13] Witness Epler then requests that the Company be permitted to apply another rate increase to North district customers on October 1, 2023 (presumably

[12] As I explained in my direct testimony, a scaleback of the Company's proposed rate increase has little impact on the relative intra-class cost impact of harmonization. Much of the Company's proposed increase to the North district rates is related to catching up with the current rates for the other customers in the class, and that part of the increase is not reduced with a lower overall revenue requirement.

[13] As I explained to the Company, the circumstances in the Columbia proceeding were decidedly different from those in the current case. See UGI-OBA-I-1

with offsetting reductions to rates for the other customers within each class), which would result in harmonized rates.[14]

Q. Please respond to Witness Epler's rebuttal.

A. Sadly, Witness Epler begins by blaming the victim. It is not the fault of North district customers that UGI Gas operates its gas system at a cost of service well in excess of that of the former owner, and it is not the fault of North district customers that UGI Gas continues to require an above system average rate of return from both N/NT and DS customers, which exacerbates the problem.

Second, Witness Epler refers to the lower rates from North district customers as an intra-class cross-subsidy. There is zero evidence for this statement. A cross-subsidy represents the difference between rate revenues and costs. UGI Gas offers no cost evidence in support of its position, because it no longer tracks costs by operating area. Thus, no party has any knowledge of the cost of providing service to North district customers relative to providing service to other customers. I acknowledge, of course, that the use of postage stamp rates across utilities is a common regulatory approach for utility tariffs. However, the use of postage stamp rates does not imply that intra-class geographic cross-subsidies do not exist, and the Company is wrong to claim that they exist without evidence.

Third, while I acknowledge that I have recommended an increase up to 2.0 times the system average in other Pennsylvania proceedings, based on my evaluation of the specific circumstances for those proceedings. The circumstances surrounding North district customers in this proceeding are wholly different from the proceeding referenced by Witness Epler.[15] Moreover, Witness Epler does not offer any example in Pennsylvania where a specific rate class or sub-class is singled out for a very large rate increase in a base

[14] It is unclear why the Company feels the need for a separate rate adjustment for Rate DS customers on October 1, 2023. In this proceeding, the Company argues that its rate case costs should be amortized over a single year, since it expects to file another rate case in a year. UGI Gas Statement No. 2-R at 8-11.

[15] See UGI Gas-OSBA-I-1, attached in Exhibit RDK-S2.

rate case, followed by an extraordinary supplementary increase outside of a base rate proceeding.

Finally, Witness Epler's rebuttal shows that the Company's standard for rate gradualism is different for small businesses than it is for residential customers. In this proceeding, the R/RT class exhibits a rate of return well below system average under every CSAS filed in this proceeding, and yet the Company's rebuttal testimony proposes an increase of only 1.43 times the system average for that class.[16] Moreover, the Company does not propose to impose another increase on R/RT customers on October 1, 2023 to make further progress toward cost based rates that it fails to achieve in this proceeding. In contrast, for some unlucky non-residential customers, the Company insists on a 2.0 times system average increase in this proceeding, followed by another increase on October 1, 2023.

Adopting the Company's proposal in this respect would be a clear indication that different regulatory standards apply to residential and non-residential customers. In contrast, my proposal relies on applying the same standard for rate gradualism to both residential and non-residential customers. I recommend against adopting the Company's proposals for mandatory rate harmonization on basic fairness grounds, namely that residential and non-residential customers should be treated comparably.

5. <u>Weather Normalization</u>

Q. In rebuttal testimony, Witness Taylor indicates that under the Company's proposed weather normalization adjustment ("WNA") mechanism, customers bills will be more stable and that rates will not vary from month to month. Do you agree?

A. I agree that the WNA will likely reduce the impact of weather fluctuations on the dollar cost of a customer's monthly gas distribution bill. I disagree that the rates per unit of gas consumed will not vary from month to month.[17] While Witness Taylor does not directly state as much, the witness presumably argues that the WNA adjusts volumes rather than rates. This is sophistry. Actual metered volumes are actual metered volumes. If a

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[16] I recognize, of course, that Witness Epler *says* that the maximum increase for the R/RT class should be 2.0 times system average. I caution the Commission to follow the old saw and "watch what they do, not what they say."

[17] See OSBA-I-2, attached in Exhibit RDK-S2.

customer has metered volumes of 50 mcf in January and 50 mcf in February, the customer will pay the same distribution bill in both months under current rates, but will almost certainly pay a different distribution bill under the WNA. I expect that customer will recognize that the rates have changed, even if Witness Taylor sees it otherwise.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT RDK-S1

ELECTRONIC WORKPAPERS

RDK WPS1: RDK Surrebuttal Cost of Service Allocation Study

*** Workpaper will be attached via email simultaneous to service of Surrebuttal Testimony***

EXHIBIT RDK-S2

REFERENCED INTERROGATORY RESPONSES

UGI-OSBA-I-1 (without attachments)

UGI-OSBA-I-2 (without attachments)

UGI Utilities, Inc. – Gas Division ("UGI Gas" or "the Company")
Base Rates Case, FPFTY Ending September 30, 2023
Docket No. R-2021-3030218
Responses to UGI-OSBA Set I

UGI-OSBA-I-1

Reference OSBA Statement No. 1, pages 15, 20-21. In any base rate cases over the past 10 years, has Mr. Knecht ever supported setting a customer class's increase to more than 1.5 times the system average increase? If so, please identify each such base rate case and provide copies of Mr. Knecht's testimony in each such base rate case.

Response:

I did not review my base rates cases for the past ten years in preparing my direct testimony in this proceeding, and undertaking such a review would be unduly costly and time-consuming. Nevertheless, I have indeed recommended in testimony that the regulator set the rate increase for a class at more than 1.5 times the system average. A recent example is at Pennsylvania Public Utility Commission Docket No. R-2021-3024296, a base rates proceeding for Columbia Gas of Pennsylvania, Inc. A copy of my direct testimony in that proceeding is included as Attachment UGI-OSBA-I-1.

In evaluating the limits for rate gradualism, I consider a variety of factors relevant to each case, including (but not necessarily limited to) the magnitude of the system increase, the relative cost performance of each class, the overall bill impact for the class, the history of relative class rate increases, and the relevant economic environment for each rate class.

UGI-OSBA-I-2

Reference OSBA Statement No. 1, page 25. Mr. Knecht states that "I am advised by counsel that OSBA intends to contest this proposal as not just and reasonable on the grounds that the substantial risk reduction benefits to the Company and the rate instability implications for customers associated with this mechanism are not reasonably reflected in the allowed return on capital claim in this proceeding."

a) Does Mr. Knecht agree with UGI Gas witness Moul that his cost of equity analysis accounts for the Company's Weather Normalization Adjustment ("WNA") mechanism? If not, please explain in detail why.

b) Does Mr. Knecht agree with UGI Gas witness Moul that each of his Gas Group members has some form of a WNA mechanism? If not, please explain in detail why.

c) Please explain in detail what Mr. Knecht means by "rate instability implications for customers associated with this mechanism."

d) Please produce all non-privileged Documents relied upon by Mr. Knecht in making this statement and in responding to subparts (a) through (c) of this interrogatory.

Responses:

a) I respectfully disagree with Mr. Moul. Outside the cloistered world of utility rate of return analysts, independent financial experts deem the U.S. equity risk premium above the ten-year Treasury yield to be in the 5.0 to 5.5 percent range for the average risk company.[1] (See, e.g., Damodaran at https://pages.stern.nyu.edu/~adamodar/ and https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4066060 , Kroll at

[1] In a welcome development in this proceeding, OCA witness David J. Garrett (OCA Statement No. 2) recognizes that allowed utility equity returns have become divorced from reality.

https://www.kroll.com/en/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates .) Even with 10-Year T-Bonds now yielding a little under 3.0 percent, the cost of equity capital for the average risk US firm is in the 8.0 to 8.5 percent range.

Natural gas distribution utilities, of course, are below-average risk investments, measured either by systematic risk (beta) or all return variability (standard deviation). Thus, the cost of equity capital for a natural gas distribution utility should have an equity risk premium materially below the 5.0 to 5.5 percent range, and a full return materially below the 8.0 to 8.5 percent range.

In my direct testimony at Docket No. R-2020-3018929 (Attachment UGI-OSBA-2a), I demonstrated that, twenty-five to thirty years ago, the equity risk premium in utility RoE awards was in the 4.0 to 5.0 percent range. Since that time, adoption of various regulatory initiatives have served to reduce the risk of utility investments, including (i) restructuring of many electric and gas utilities (reducing fuel price and generation risk), (ii) fuel-adjustment clauses, such as Pennsylvania's PGC, (iii) automatic capital passthrough mechanisms, such as Pennsylvania's DSIC, (iv) weather normalization mechanisms (reducing utility weather risk), and (v) rate decoupling mechanisms (which shift virtually all volume risk to ratepayers). Despite this trend of risk reduction, utility regulators have allowed the implied equity risk premium in RoE awards to rise to 7.0 to 8.0 percent, far above that of average risk US corporations. While the reasons for this trend cannot be known with certainty, I hypothesized in Attachment UGI-OSBA-2a that this trend reflects (a) higher utility spending in regulatory proceedings, (b) excessive regulatory reliance on DCF methods for deriving RoE (with the circular reliance on analysts' growth estimates combined with the bizarre assumption that natural gas distribution companies will experience dividend growth rates that exceed GDP growth rates forever) and regulatory capture (wherein regulators and governments see utilities as partners in achieving social aims through ratepayer-subsidized programs such as low-income assistance and energy conservation measures, and they reward the utilities with excessive returns).

As Mr. Moul recommends that the allowed RoE be set at 11.20 percent, which has an implied equity risk premium that exceeds 8.2 percent, I conclude that Mr. Moul has not reflected the risk reduction impacts of the adoption of weather normalization and rate decoupling mechanisms, but in fact has increased the implied risk premium above historical norms.

b) I have not reviewed the rate structures of the firms included in Mr. Moul's Gas Group.

c) With a "real time" weather normalization mechanism and no deadband as proposed by UGI Gas, the volumetric rate paid by Rate R/RT and N/NT customers for delivered gas will necessarily vary from month to month. In the current rate mechanism, the base rates volumetric charge is constant from month-to-month, save for the effects of the DSIC.

d) The specific documents that I relied upon in responding to this interrogatory are attached to the responses or referenced with URLs. My responses also rely on my academic training in economics and finance, as well as my experience in utility rate proceedings in the past thirty years.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3030218**
UGI UTILITIES, INC. (Gas Division)	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Rebuttal Testimony labelled OSBA Statement No. 1-S and associated Exhibits RDK-S1 and RDK-S2 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: May 27, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI Utilities, Inc. – Gas Division	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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/s/ Steven C. Gray

DATE: May 27, 2022

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pa. Public Utility Commission	:	
	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
	:	
UGI Utilities, Inc. – Gas Division	:	

DIRECT TESTIMONY OF

CHRISTOPHER REYES

ON BEHALF OF NRG ENERGY, INC.

(***PROPRIETARY VERSION***)

TOPICS:

Standards of Conduct
Auburn Gathering System
Operational Issues
Weighted Average Cost of Delivered Gas

APRIL 20, 2022

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Christopher Reyes and I am Sr. Manager, Regional Operations (NY Metro, North East & Mid-Atlantic) for NRG Energy, Inc. ("NRG"). My business address is 194 Wood Avenue S., Iselin, New Jersey 08830.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have worked in the Oil & Gas industry in positions of increasing responsibility since 1995. Immediately prior to my current position that I have been in since January 5, 2021 when NRG completed the acquisition of Direct Energy from Centrica plc, I held the same title and fulfilled the same responsibilities with Direct Energy dating back to June 2017. Before that, I was Sr. Natural Gas Trader for Direct Energy from January 2014 until June 2017. My prior employer, before I joined Direct Energy, was Hess Corporation where I worked for over 18 years in various positions, including Sr. Natural Gas Trader, Natural Gas Trader and Sr. Wholesale Natural Gas Scheduler. I received a Master of Business Administration from Webster University in Finance in 2001 and a Master of Arts, Business and Organizational Security Management, from Webster University in 2003.

Q. WHAT ARE YOUR KEY RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. In my current role, I am responsible for managing both the Retail Natural Gas Pricing and Scheduling Teams.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION?

A. No.

Q. ON WHOSE BEHALF IS THIS DIRECT TESTIMONY OFFERED?

This Direct Testimony is offered on behalf of NRG. As natural gas suppliers ("NGSs") licensed by the Pennsylvania Public Utility Commission ("Commission"), NRG's subsidiaries supply natural gas services to retail consumers in the Company's service territory.[1]

Q. PLEASE DESCRIBE NRG.

NRG is a leading integrated power company built on dynamic retail brands and diverse generation assets and home services company powered by its customer-focused strategy, strong balance sheet, and comprehensive sustainability framework. A Fortune 500 company, NRG brings the power of energy to millions of North American customers. Our family of brands help people, organizations and businesses achieve their goals by leveraging decades of market expertise to deliver tailored solutions. Working in concert, its dynamic multi-brand retail strategy coupled with supply risk-management forms a uniquely positioned, integrated competitive energy provider. Its retail brands serve more than six million customers across North America, including a significant share in Pennsylvania — so significant, in fact, that NRG's northeast retail business is headquartered in Philadelphia. NRG's subsidiaries include several NGSs that are actively serving residential, commercial, industrial and institutional customers in the Companies' service territories and throughout Pennsylvania.

[1] As NGSs in Pennsylvania, NRG subsidiaries hold licenses as follows: Independence Energy Group d/b/a Cirro Energy: A-2013-2396449; Reliant Energy Northeast LLC d/b/a NRG Home, NRG Business, NRG Retail Solutions: A-2015-2478293; Green Mountain Energy Company: A-2017-2583732; XOOM Energy Pennsylvania, LLC: A-2012-2283967; Stream Energy Pennsylvania, LLC: A-2012-2308991; Direct Energy Services, LLC: A-125135; Direct Energy Business, LLC: A-125072; Direct Energy Business Marketing, LLC: A-2013-2365792; Gateway Energy Services Corporation: A-2009-2138725.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to offer NRG's perspectives on specific aspects of Supplement No. 32 to UGI Tariff Gas – Pa. P.U.C. Nos. 7 and 7S filed by UGI Utilities, Inc. – Gas Division ("UGI" or "Company") on January 28, 2022, and to describe concerns regarding the Company's overall natural gas operations, particularly as they affect the retail natural gas market. Specifically, my Direct Testimony addresses the following issues: (1) Commission's Standards of Conduct; (2) Auburn Gathering System; (3) Operational Issues; and (4) Weighted Average Cost of Delivered Gas.

Q. DO YOU HAVE SPECIFIC RECOMMENDATIONS IN EACH OF THESE AREAS?

A. Yes. My recommendations can be summarized as proposing that the Commission:

- Take various measures designed to ensure UGI's compliance with the Standards of Conduct, including scrutiny of internal information by the Bureau of Technical Utility Services, the Bureau of Audits and the Office of Competitive Market Oversight;
- Require UGI to provide information to NGSs that outlines the full capabilities of its delivery system, including the ability to move gas between regional pools;
- Direct UGI to implement automated programming for notification of utility cuts to nominations over weekends or implement weekend staffing that would offer the same level of service that is provided on weekdays; and
- Mandate specific changes to UGI's handling of Weighted Average Cost of Delivery gas rates to improve NRG's ability to accurately estimate costs in setting natural gas prices for its supply customers.

Q. ARE YOU SPONSORING ANY EXHIBITS?

Yes. Below is a table of the exhibits I am sponsoring. All are attached to my Direct Testimony.

NRG Exhibit CR-1	UGI's Response to NRG-I-1
Confidential NRG Exhibit CR-2	UGI's **Confidential** Response to NRG-I-4
Confidential NRG Exhibit CR-3	UGI's **Confidential** Response to NRG-I-2
NRG Exhibit CR-4	UGI's Response to NRG-I-9
NRG Exhibit CR-5	UGI's Email dated July 30, 2021
NRG Exhibit CR-6	UGI's Response to NRG-I-10
NRG Exhibit CR-7	April 2022 Notices Posted on EBB

II. STANDARDS OF CONDUCT

Q. PLEASE DECRIBE THE STANDARDS OF CONDUCT.

A. The Commission has Standards of Conduct that are applicable to natural gas distribution companies ("NGDCs") and NGSs at 52 Pa. Code § 62.142, which contain several key provisions that:

- Prohibit the sharing of NGDC employees who have responsibility for operating the distribution system, including natural gas delivery or billing or metering, as well as those responsible for marketing and customer service, with an affiliated NGS;[2]
- Require an NGDC to reasonably allocate to its affiliated NGS the costs or expenses for general administration or support services provided to its affiliated NGS;[3]
- Obligate an NGDC and its affiliated NGS to maintain separate books and records, and require an NGDC to avoid cross-subsidies, to fully allocate shared facilities between the NGDC function and the affiliated function, and to maintain its accounts and records so that the costs incurred on behalf of an affiliated NGS are clearly identified;[4]
- Prohibit an NGDC from applying a tariff provision in a manner that would give its affiliated NGS preference over other NGSs with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, non-delivery and other services provided to its affiliated NGS.[5]

Q. WHAT IS THE SIGNIFICANCE OF THE COMMISSION'S STANDARDS OF CONDUCT?

A. The significance of the Commission's Standards of Conduct is that UGI's affiliated NGS, UGI Energy Services, LLC ("UGI-ES"), is operating in the retail market as a licensed NGS.[6] To my knowledge, no other Pennsylvania NGDC has an affiliated NGS. As a

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[2] 52 Pa. Code § 62.142(a)(13).

[3] 52 Pa. Code § 62.142(a)(9).

[4] 52 Pa. Code § 62.142(a)(12).

[5] 52 Pa. Code § 62.142(a)(2).

[6] NRG Exhibit CR-1 (UGI's Response to NRG-I-1).

licensed NGS, UGI-ES is competing against NRG and other nonaffiliated NGSs in supplying natural gas services to retail customers in UGI's service territory. To the extent that UGI is not vigilant about strict adherence to the Standards of Conduct, UGI-ES could have an unfair advantage over nonaffiliated NGSs, which prevents the robust functioning of the competitive retail market. In initiating the proposed rulemaking that led to adoption of the Standards of Conduct, the Commission emphasized the need to "ensure that consumers of natural gas will be able to shop for gas that is marketed on a level playing field for all market participants."[7]

A. <u>Sharing of Employees</u>

Q. DO YOU HAVE ANY CONCERNS ABOUT UGI'S COMPLIANCE WITH THE STANDARDS OF CONDUCT ADDRESSING THE SHARING OF EMPLOYEES?

A. Yes. I have personally observed employees migrating back and forth between UGI and UGI-ES, which shows that they are being shared by both entities. One day an employee might be the director of an operations team for UGI and the next day the same employee is a director in UGI-ES. When an employee serves as director for major accounts at UGI and then migrates to UGI-ES as director of sales and marketing, the potential exists for the intelligence to be transferred such that UGI-ES is aware of the products being offered by its competitors. It is also not clear if or how their salaries are allocated between UGI and UGI-ES.

Q. WHAT DO YOU RECOMMEND AS A SOLUTION?

A. I recommend that the Commission direct UGI to provide a full accounting to the Bureau of Technical Utility Services ("TUS"), within 60 days after the issuance of a final order

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7 *Permanent Standards of Conduct Pursuant to 66 Pa.C.S. §2209(b)*, Docket No. L-00030162 (Proposed Rulemaking Order entered September 23, 2003, at 1).

in this proceeding, of all employees, along with their titles and job descriptions, who migrate back and forth between UGI and UGI-ES, along with documentation of how their salaries are allocated. I am not referring to employees who legitimately transfer from one entity to the other, provided the transfer is not for the purpose of avoiding a violation of the provision in the Standards of Conduct. Rather, I am referring to employees in director level or high management level positions who are shared by both UGI and UGI-ES. Given the importance of the prohibition in the Standards of Conduct against sharing of certain employees between UGI and UGI-ES, and the responsibility the Commission has to oversee the proper functioning of the retail natural gas market, I believe that the affiliate relationship between these entities warrants scrutiny by TUS and any further action as may be necessary.

B. <u>Reasonable Allocation of Costs for General Administration or Support Services</u>

Q. DO YOU HAVE ANY CONCERNS ABOUT UGI'S COMPLIANCE WITH THE PROVISION REQUIRING UGI TO REASONABLY ALLOCATE TO UGI-ES THE COSTS OR EXPENSES FOR GENERAL ADMINISTRATION OR SUPPORT SERVICES PROVIDED TO UGI-ES?

A. Yes. In response to a discovery request, UGI explained that it maintains a Cost Allocation Manual ("CAM") that discusses the methods used to allocate or direct charge for services between UGI-ES and the Company. UGI also attached its confidential CAM.[8]

Q. DOES THE CAM SATISFY YOUR CONCERN?

A. Not really. Provided that UGI is strictly following its CAM, it appears that costs for general administration or support services are probably being fairly allocated to UGI-ES. However, I note that NRG's discovery request asked for supporting documentation that

[8] **Confidential** NRG Exhibit CR-2 (UGI's **Confidential** Response to NRG-I-4).

shows compliance with the provision in the Standards of Conduct, which was not furnished. Since this involves an internal allocation process, I do not have access to information that demonstrates compliance. Yet, the proper allocation is critical to the healthy functioning of the competitive market due to the importance of UGI fully allocating the costs to UGI-ES that it incurs to provide general administration or support services.

Q. WHAT DO YOU RECOMMEND?

A. To the extent that the Commission is not already including this issue as part of its periodic audits of UGI, I recommend that it direct the Bureau of Audits to examine UGI's compliance with the CAM in allocating costs to its affiliate NGS. Without such review, it is not possible to verify that the allocations are being fairly handled. If UGI is not properly allocating costs to UGI-ES, nonaffiliated NGSs in the market are competing against a UGI-ES product that does not reflect all of the costs that are incurred to offer it to consumers, which again gives the NGS affiliate a competitive edge over those NGSs that are not affiliated with UGI. Such an advantage runs contrary to the way in which a truly competitive market should operate.

C. Separate Books and Records

Q. WHAT DOES UGI DO TO COMPLY WITH THE REQUIREMENT FOR SEPARATE BOOKS AND RECORDS AND THE AVOIDANCE OF CROSS SUBSIDIES?

A. In response to a discovery request, UGI provided its confidential training materials that simply set forth these requirements, without any details or explanations as to how actual compliance is achieved.[9]

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[9] **Confidential** NRG Exhibit CR-3 (UGI's **Confidential** Response to NRG-I-2).

Q. HOW DO YOU RESPOND?

A. Although the materials advise employees of these requirements in the Commission's Standards of Conduct, UGI has not indicated how frequently the training materials are provided to employees. Further, UGI has not explained whether it audits the practices of employees to ensure that all of these requirements are followed. Having subsidiaries in the retail gas market competing against UGI-ES, NRG believes that additional steps are necessary to consider whether any existing practices are resulting in UGI giving UGI-ES an unfair competitive advantage.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that in tandem with the audit I have suggested to examine the proper allocation of costs by UGI to UGI-ES, the Commission also direct the Bureau of Audits to review UGI's books and records to confirm that they are maintained separately from UGI-ES, that shared facilities between the UGI and UGI-ES functions are fully allocated and that UGI maintains its accounts and records so that the costs incurred on behalf of UGI-ES are clearly identified. Again, the importance of performing this review is to ensure that UGI is not giving UGI-ES a competitive edge over nonaffiliated NGSs.

D. <u>No Preference in Provision of Services</u>

Q. DO YOU HAVE CONCERNS ABOUT UGI'S COMPLIANCE WITH THE PROHIBITION AGAINST GIVING UGI-ES PREFERENCE OVER OTHER NGSS IN THE PROVISION OF SERVICES?

A. Yes. In a discovery request, NRG asked how UGI ensures compliance with the provision that prohibits an NGDC from giving its affiliated NGS preference over other NGSs with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, non-delivery and other services provided to its affiliated NGS. In response, the Company provided confidential training materials.[10]

Q. PLEASE RESPOND.

A. Although the materials advise employees of this provision in the Commission's Standards of Conduct, UGI has not indicated how frequently the training materials are provided to employees. UGI has further not explained whether it audits the practices of employees to ensure that all of these requirements are followed. Having subsidiaries in the retail gas market competing against UGI-ES, NRG believes that additional steps are necessary to consider whether any existing practices are resulting in UGI giving UGI-ES an unfair competitive advantage.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission direct that UGI periodically conduct an internal audit that is designed to review compliance with this provision of the Standards of Conduct and report to the Office of Competitive Market Oversight ("OCMO") on a quarterly basis all measures it has taken and how it has handled any departures from the requirements that it may uncover during an internal audit. It is my understanding that OCMO was created to oversee competition in the retail natural gas supply market, so as to promote the development of the competitive retail market and address obstacles faced by NGSs participating in this market.[11] Therefore, ensuring that UGI is taking the necessary steps to comply with rules that prohibit the showing of a preference to an NGS affiliate appears to fall squarely under that mission.

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[10] **Confidential** NRG Exhibit CR-3 (UGI's **Confidential** Response to NRG-I-2).

[11] https://www.puc.pa.gov/natural-gas/committees-working-groups/natural-gas-office-of-competitive-market-oversight-ocmo/

III. AUBURN GATHERING SYSTEM

Q. PLEASE DECRIBE UGI'S DIRECT TESTIMONY CONCERNING A NEW CAPACITY LEASE AGREEMENT.

A. UGI Witness Brown references a new Capacity Lease Agreement, which allows the Company direct access to natural gas supplies for delivery from the Tennessee Gas Pipeline through the UGI Gas Auburn Gate Station into the Auburn Gathering System, which is owned by UGI-ES.[12]

Q. DO YOU HAVE ANY CONCERNS ABOUT THIS NEW CAPACITY LEASE AGREEMENT?

A. Based on UGI's discovery response regarding the purpose of this new Capacity Lease Agreement, which was to provide a conduit for an additional source of natural gas supply into an area of the Company's natural gas service territory that is exclusively served by the UGI-ES Auburn Gathering System, as a least cost approach to other options,[13] I do not have a particular concern with this agreement. However, I do have concerns about UGI-ES undertaking risk-free projects to acquire assets and then selling them to UGI, with the rate base bearing the burden. This concern is based on the fact that several of UGI's recent supply expansion activities, including the Auburn Gathering System, have been met by UGI-ES.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE TRANSPARENCY OF UGI'S DELIVERY SYSTEM?

A. Yes. During past Interstate Open Seasons, when available interstate pipeline capacity is being bid, I am aware of instances where the capability to move gas between regional pools on UGI's delivery system was known only to UGI and UGI-ES. For example, the

[12] UGI Statement No. 1 at 25-26.

[13] NRG Exhibit CR-1 (UGI's Response to NRG-I-1).

Sunberry Capacity had been granted access to the UGI south pool via a spur on UGI central that was never available or disclosed to the system marketers and was only discovered during offline settlement discussions during the 2019 UGI rate case after UGI-ES had subscribed to the capacity. Had the information been public, there would have been a more robust interest in the open season by competitors of UGI-ES.

Q. HOW WOULD UGI-ES KNOWN OF THE CAPABILITY OF UGI'S DELIVERY SYSTEM?

A. Due to the sharing of employees between the two entities and the inevitable transfer of knowledge.

Q. WHAT DO YOU RECOMMEND?

A. The Commission should direct UGI to provide information to NGSs that outlines the full capabilities of its delivery system when it receives gas from the interstate pipelines. These capabilities include how UGI is able to move gas between regional pools so as to ensure that NGSs are granted the same access and have the same understanding that UGI-ES is afforded.

IV. <u>OPERATIONAL ISSUES</u>

Q. DO YOU HAVE ANY CONCERNS REGARDING OPERATIONAL ISSUES THAT ARE AFFECTING NRG'S PARTICIPATION IN THE RETAIL MARKET?

A. Yes. NRG is experiencing an ongoing operational issue regarding the lack of timely notifications of utility cuts, which occur when a nomination made by an NGS needs to be corrected, over the weekend. A nomination is the action taken by an NGS to communicate and confirm that a particular amount of gas is to be delivered or received at the gas delivery point and/or the alternative gas delivery point(s) and providing all information that may be necessary to cause such delivery or receipt to occur. Through the nomination, the NGS is providing a pre gas day notification of intended gas consumption by its customers for a gas day and must follow the NGDC's gas nomination procedures established by tariff.

Q. WHY WOULD NOMINATIONS NEED TO BE CORRECTED?

A. For a variety of reasons. This process involves a robust third-party market, with entities making changes and information constantly changing outside the control and/or knowledge of NGSs. For instance, an interstate pipeline may experience constraints or operational issues. Or a transposition error could have occurred in identifying the contract.

Q. WHAT NORMALLY HAPPENS WHEN A CORRECTION IS NEEDED?

A. When the utility discovers an error during the confirmation cycle and does a cut on a weekday, the NGS is able to correct the nomination and avoid penalties imposed by NGDCs and the pipelines. However, on weekends, an NGS does not receive notice of the utility cut from UGI and has no ability to promptly correct the nomination. The effect of this is that the best NRG can hope to do is convince the pipelines and UGI to allow the submission of a retroactive nomination, which they have no obligation to do. This may subject NRG to penalties, which would be exacerbated if the utility cut occurs when an operational flow order or operational matching order is in effect due to the steeper penalties that are imposed. Particularly given the fact that UGI has an affiliated NGS operating in the competitive market, the risk of penalties needs to be solved since the imposition of penalties on NRG would benefit its competitor, UGI-ES.

Q. HOW DO YOU RECOMMEND UGI ADDRESS THIS ISSUE?

A. I recommend that UGI be directed to implement automated programming for these notifications or implement weekend staffing that would offer the same level of service as is provided on weekdays. Most utilities use automatic notifications so that an NGS has an opportunity to timely correct the nomination and avoid the imposition of penalties. In discovery, NRG asked UGI whether it has considered the use of automatic notifications of utility cuts over the weekend. UGI responded that it was not aware of ongoing operational issues concerning a lack of notifications with regard to utility supply cuts during weekend periods. Therefore, the Company has not considered implementing automated programming for these notifications but welcomes additional communications which would help UGI understand the frequency and impact of the alleged concerns.[14]

Q. PLEASE RESPOND.

A. During a supplier collaborative in 2021, this issue was raised with UGI. An email from UGI dated July 30, 2021 demonstrates that NRG brought the issue to UGI's attention, asking to see utility cuts in real time.[15] Automating the process was the precise request made at that time. If UGI continues to be unable to automate the process, as I note above, it should be able to provide weekend staffing to ensure that NGSs receive prompt notifications about utility cuts during the confirmation cycle of the nomination process.

V. WEIGHTED AVERAGE COST OF DELIVERED GAS

Q. PLEASE DESCRIBE THE ISSUE WITH THE WEIGHTED AVERAGE COST OF DELIVERED GAS.

A. UGI uses weighted average cost of delivered ("WACOD") gas for recovery of charges for released capacity and provides monthly information on its Electronic Bulletin Board ("EBB") to show the WACOD gas rates as reflecting interstate pipeline rate changes approved by the Federal Energy Regulatory Commission. However, this information

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[14] NRG Exhibit CR-4 (UGI's Response to NRG-I-9).

[15] NRG Exhibit CR-5 (UGI's Email dated July 30, 2021).

does not show the projected total dollar impact of each specific pipeline rate case on the WACOD gas rate each month. This is a problem because the individual impact of a rate case affects the natural gas prices that NRG is charging customers. I took the screenshot below from UGI's EBB. The portion in highlighting shows what is provided and notes only which rate cases are included. However, it does not tell us what the estimated maximum rate impact is, which would give us the ability to isolate the individual impacts of a specific rate case. For instance, following the line that indicates that the WACOD rate change "Includes TETCO Base Rate at Docket RP21-1188 for April 2022," NRG is looking for the addition of "with an estimated maximum rate impact of $0.XX." I am not asking UGI to undertake any forecasting that it is not already doing, but rather to include the forecasts they have made to show the impact of the individual rate cases over a 12-month period following implementation.

UGI Utilities, Inc. Choice Projected WACOD Rates ($/dth/month)

Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23
$26.6383	$8.5469	$8.5961	$8.5386	$8.5897	$8.5897	$8.5358	$9.1249	$23.8220	$25.2212	$25.2217	$25.0390

Updated February 22, 2022

WACOD Rate Changes
Includes TETCO Base Rate Case at Docket RP21-1188 for April 2022
Includes EGTS Base Rate Case at Docket RP21-1187 for April 2022
Includes TETCO Base Rate Case at Docket RP21-1001 for March 2022
Includes adjustment due to Docket RP21-1001 not included February 2022 calculations

UGI Utilities, Inc. Choice Projected Capacity Release Rates

The Company will assess the WACOD for an NGSs Peak Day Delivery Requirement ("PDDR") via a capcity release.

Example	Mar-22
NGS PDDR (dth)	100
WACOD	$26.6383
Total Cost	$2,663.83

Pipeline Released	Annual Firm Transportation Allocation	Capacity Release Quantity (dth/day)	Capacity Release Term	Capacity Release Rate ($/dth/month)	Total Capacity Release Costs
Texas Eastern	14.2%	14	Monthly	$ 176.1651	$ 2,466.31
Transco	4.5%	5	Annual	$ 15.5035	$ 77.52
Columbia	5.1%	5	Annual	$ 15.0000	$ 75.00
Tennessee	3.2%	3	Annual	$ 15.0000	$ 45.00
Total	27.0%	27	Annual	$ 26.6383	$ 2,663.83

Q. WHAT DO YOU RECOMMEND?

A. The simple solution is for UGI to show this more detailed information on its EBB. The Company is already providing WACOD gas rates on a monthly basis. In a discovery response, UGI indicated that its WACOD calculation process utilizes only effective pipeline rates and does not support rate segmentation as described.[16]

Q. HOW DO YOU RESPOND?

A. While UGI's WACOD calculation process may not support the rate segmentation as described, it is my understanding that the information about the effect of pipeline rate changes is available and can be provided either on the EBB or through an alternate means. For example, UGI could provide suppliers with information via electronic mail of the impact of each rate case on the WACOD calculation. NRG should not be required to request this information each month. Rather, UGI should automatically furnish it, through whatever means the Company determines is the most efficient. Below is a screen shot showing what UGI has posted in the format that we are requesting, along with a 12-month of forward impact from the implementation of a rate change.

UGI Utilities, Inc. Choice Projected WACOD Rates ($/dth/month)

	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21
	$4.3366	$6.5519	$21.8503	$25.6154	$22.1369	$21.6328	$21.6632	$7.5642	$7.6053	$7.4707	$7.5202	$7.5200
WACOD Increase/(Decrease) related to TCO Rate Case:	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$1.5700	$1.5700	$1.2400	$1.2400	$1.2400	$1.2400	$1.2400

Updated August 13, 2020

WACOD Rate Changes

WACOD includes impact of proposed rate increases to be effective Feb 2021, for services provided by Columbia Gas Transmission, based on Columbia's proposed rates at Docket RP20-1060-000.
Does not include the rate increase impact of Columbia's Preferred Case at Docket No. RP20-1060-000.

UGI Utilities, Inc. Choice Projected Capacity Release Rates

The Company will assess the WACOD for an NGSs Peak Day Delivery Requirement ("PDDR") via a capcity release.

Example	Sep-20
NGS PDDR (dth)	130
WACOD	$4.3366
Total Cost	$563.76

Pipeline Released	Annual Firm Transportation Allocation	Capacity Release Quantity (dth/day)	Capacity Release Term	Capacity Release Rate ($/dth/month)	Total Capacity Release Costs
Texas Eastern	11.2%	11	Monthly	$ 12.4327	$ 136.76
Transco	4.3%	4	Annual	$ 31.0000	$ 124.00
Columbia	7.0%	7	Annual	$ 30.0000	$ 210.00
Tennessee	2.8%	3	Annual	$ 31.0000	$ 93.00
Total	25.3%	25	Annual	$ 5.6376	$ 563.76

16 NRG Exhibit 6 (UGI's Response to NRG-I-10).

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT WACOD RATES?

A. Yes. This month, UGI placed a notice on its EBB regarding an adjustment for Economic Benefit of Peaking Service ("EBPS"). The purpose of the adjustment is to credit the economic benefit realized from the use of the peaking assets due to an error that the Company made in implementing a change to the peaking service contract cost allocations as a result of the Settlement of the 2019 UGI Rate Case at Docket No. R-2018-3006814. UGI also posted a notice of an adjustment to the Rate LFC WACOD capacity release rates that have not properly reflected the portion of a customer's daily firm requirement allocated to delivered supply.[17] The result of this adjustment is an increase to the LFD and DS WACOD rates due to UGI's under recovery of peaking charges from the prior 2 years .

Q. WHAT IS YOUR CONCERN ABOUT THESE NOTICES?

A. The issue that I have is that both the EBPS and the LFD gross up should be removed from the LFD WACOD rates. These credits/charges are currently included on the NGS's invoice. When both costs and credits are handled in the WACOD rates, the amounts are artificially high or low and as the costs or credits roll off, the rates can change dramatically especially when the utility is only posting a 12-month rate schedule.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the EBPS and LFD gross up be handled similar to the DS rate, which UGI bills directly to customer. NRG should not be in a position of explaining UGI errors to its supply customers or be required to decide how to allocate credits/costs resulting from UGI adjustments, particularly when some of the affected customers were not being

[17] Exhibit NRG Exhibit CR-7 (April 2022 Notices Posted on EBB).

served by NRG when the charges were initially included on bills. In addition, similar to the issue described above about needing to know the impact of individual rate NRG needs to see any non-recurring costs or credits that are in the WACOD rate line itemed so that we can estimate the forward costs accurately.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes; however, I reserve the right to supplement this testimony as may be appropriate.

Verification

I, Christopher Reyes, state that I am Sr. Manager, Regional Operations (NY Metro, North East & Mid-Atlantic) for NRG Energy, Inc. ("NRG") and providing the foregoing Direct Testimony of NRG. I hereby state that the facts contained in the foregoing Direct Testimony are true and correct to the best of my knowledge, information and belief. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

April 20, 2022

/Christopher Reyes/
Christopher Reyes
Sr. Manager, Regional Operations, NRG Energy, Inc.

NRG Exhibit CR-1

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to NRG Set I (1 thru 10)
Delivered on April 11, 2022

NRG-I-1

Request:

Reference Direct Testimony of Christopher R. Brown, pages 25-26. Mr. Brown references a new Capacity Lease Agreement allowing the Company direct access to natural gas supplies for delivery from the Tennessee Gas Pipeline through the UGI Gas Auburn Gate Station, into the Auburn Gather system, a natural gas gathering system located in northeast Pennsylvania, owned by UGI Energy Services, LLC ("UGI-ES"), an affiliate of the Company,

A. Please confirm that UGI-ES is a natural gas supplier ("NGSs") licensed by the Commission to provide retail gas supply services to customers throughout the Commonwealth of Pennsylvania, including in the Company's service territory. If you do not confirm, please explain.

B. Please explain the rationale underlying the new Capacity Lease Agreement. In responding, please indicate whether this approach was the least cost option on available capacity or whether the goal was to remove under-utilized assets from the UGI-ES books.

Response:

A. UGI-ES is a natural gas supplier licensed by the PA PUC.

B. The purpose of the Capacity Lease Agreement was to provide a conduit for an additional source of natural gas supply (Tennessee Gas Pipeline Company) into an area of the Company's natural gas service territory that is exclusively served by the UGI-ES Auburn gathering system that is currently supplied exclusively by local natural gas production wells. Use of the existing UGI-ES gathering system offered the least cost approach as other options would have required greenfield construction of a parallel nature that would have been much more expensive.

Prepared by or under the supervision of: Christopher R. Brown

NRG Exhibit CR-2

Confidential

NRG-I-4

Request:

Please describe how the Company reasonably allocates to UGI-ES the costs or expenses for general administration or support services provided to its UGI-ES. Provide supporting documentation. 52 Pa. Code § 62.142(a)(9).

Response:

The Company maintains a Cost Allocation Manual that discusses the methods used to allocate or direct charge for services between UGI-ES and the Company in accordance with Commission Orders approving such services. Please see CONFIDENTIAL Attachment NRG-I-4 for a copy of the Cost Allocation Manual.

Prepared by or under the supervision of: Vivian K. Ressler

UGI UTILITIES, INC.

COST ALLOCATION MANUAL

September 2020

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COST ALLOCATION PRINCIPLES

Purpose of Manual

It is important that utility costs incurred to support non-utility affiliates be clearly identified and charged to those affiliates to avoid any inadvertent subsidization of those businesses. It is equally important that charges to the utility from affiliates (including the holding company and any shared services company) be reasonable and adequately supported. Because UGI Utilities, Inc. consists of two regulated utility businesses (Gas and Electric), it is also imperative that costs of shared functions are reasonably allocated across those businesses, as each of these two businesses is regulated separately, has a different customer base, and have different sets of rates.

As defined by the National Association of Regulatory Utility Commissioners (NARUC) Guidelines for Cost Allocations and Affiliate Transactions, a cost allocation manual (CAM) should include, but not be limited to:

- An organization chart of the holding company, depicting all affiliates, and regulated entities.
- A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.
- A description of all assets, services and products provided by the regulated entity to non-affiliates.
- A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

The purpose of UGI Utilities, Inc.'s ("UGI Utilities" or the "Company") Cost Allocation Manual ("CAM") is to comply with the above principles, in so doing, to provide the Pennsylvania Public Utility Commission ("PUC") with transparency into processes and procedures that govern how costs are allocated both amongst UGI Utilities' regulated businesses and between UGI Utilities and its various affiliates.

The CAM and its appendices address situations where, under applicable affiliated interest standards, costs are to be allocated on the basis of cost. Thus, the CAM does not address (1) purchases or sales of gas supply assets or services at market rates or at FERC-regulated rates which are subject to annual review in PUC Purchase Gas Cost ("PGC") proceedings, including, but not limited to, purchases or sales of gas commodity, pipeline capacity, storage capacity and asset management services; (2) purchases or sales of wholesale electric supply assets or services at market rates or at FERC-regulated rates pursuant to a PUC-approved default service plan; (3) the provision or receipt of goods or services at PUC or FERC-approved tariff rates and terms and conditions of service; or (4) the provision or receipt of goods or services pursuant to a PUC-approved affiliated interest agreement or security certificate authorizing non-cost based pricing or rates which, in the case of UGI Utilities, Inc. – Gas Division and UGI Utilities, Inc. – Electric Division, may include , HVAC services, HVAC employees services, retail natural gas or electric service for utility buildings, propane supply services or specific ground lease payments pursuant to the terms of PUC-approved affiliated interest agreements authorizing non-cost based charges.

UGI Corporation Organizational Structure and Common Services

UGI Utilities is a wholly owned first tier subsidiary of UGI Corporation. See Appendix A for UGI Corporation's organizational chart, which shows all first-tier subsidiaries. UGI Corporation provides common services including finance, legal, executive, and other administrative activities to its subsidiaries, and where such costs can be directly attributed to a particular subsidiary, they are direct assigned to it. With respect to the expenses incurred by UGI Corporation associated with common activities provided to all of UGI Corporation's operating subsidiaries, such expenses are allocated to first-tier subsidiaries using UGI Corporation's Modified Wisconsin Formula ("MWF"), which measures the relative size and activity of each first-tier subsidiary in determining a reasonable allocation method, or another allocation factor tailored to the nature of the service being provided. This calculation and related expense allocation are updated annually by UGI Corporation. For more information describing the common services allocated by UGI Corporation, as well as the details of the MWF calculation and related allocation, see Appendix B for UGI Corporation's CAM.

Within UGI Corporation are several executives that oversee various aspects of the Company's natural gas line of business ("UGI Natural Gas"). UGI Natural Gas consists of UGI Utilities, UGI Energy Services, and UGI HVAC Enterprises, and their various subsidiaries. UGI Natural Gas executives perform Chief Executive, Information Technology, Human Resources, Communications, and Strategic roles. Costs associated with these executives are allocated using various methodologies including MWF (Strategic), employee headcount (IT, HR and Communications), or on a pre-determined time allocation (Chief Executive).

UGI Utilities and Affiliates Organizational Structures

UGI Utilities owns and operates a natural gas distribution business and an electric distribution business. The "Gas Utility" segment consists of the regulated natural gas distribution business of UGI Utilities. The "Electric Utility" segment consists of the regulated electric distribution business of UGI Utilities. See Appendix C for UGI Utilities' organizational chart.

UGI Utilities' various affiliates are comprised of its subsidiaries (none of which are actively operating as utilities), UGI Corporation, and other subsidiaries of UGI Corporation. See Appendix D for UGI Corporation's other subsidiaries' organizational charts.

Cost Allocation Philosophy and Process

Internal cost allocations amongst the businesses of UGI Utilities (Gas Utility and Electric Utility), as well as cost allocations into and out of these businesses, are governed by the use of a fully distributed cost allocation methodology. A fully distributed cost allocation is premised on the concept of distributing all costs to business activities, either through direct charges or allocations, based on a consistent method of determining cost causation from period to period so that reasonable cost attribution occurs. Under a fully distributed cost allocation, all direct and indirect expenses such as labor, supplies, and other related expenses are included in the cost of the various business activities performed. In addition, overhead charges, which may include fringe benefits and overhead expenses, are applied to the direct and indirect labor charges captured to arrive at the fully distributed cost for each business activity performed. All resultant cost allocations both between UGI Utilities and its subsidiaries and between UGI Utilities and its subsidiaries and other affiliates, are predicated on some relevant measure of cost causation for that business activity.

Whenever feasible, all costs which can be specifically attributed are charged directly from the business incurring the cost to the business receiving the benefit. There are instances, however, where direct charging is not practical, and in those instances, an allocation methodology which reasonably apportions costs based on the relative benefit of the service to each affected business is used to allocate those expenses amongst the applicable businesses.

Direct Charging of Costs

Direct charging of costs internally from one UGI Utilities business to another, or externally to other non-regulated affiliates, can occur through several types of procedures. The direct charging of labor costs is frequently accomplished using the time recording system, which records individual hours. Whenever any employee performs activities on behalf of another affiliate, the amount of time and work effort required is charged to a project that is coded for intercompany billing to the affiliate, unless that time is charged to the affiliate utilizing an indirect cost allocation methodology (see below).

In direct charging supplies, services, and other non-labor costs received from third parties to another business unit, the third-party invoice associated with those items should, for the most part, be coded for payment with a project that is flagged for intercompany billing if an affiliate gave rise to the necessity to procure those items. If more than one entity is responsible for the procurement of the items, the invoice balance is allocated among the different entities, which will facilitate intercompany billing of the appropriate affiliates.

Other costs, which do not have an associated invoice, may be direct charged to and from affiliates. Examples of these expenses would be postretirement expenses, employee contributions and withholdings, and employee expenses. These are described in further detail in Appendix G.

A key element of the process of direct charging of costs is timely communication with the associated business. The responsible individual or department making the direct charge should inform the associated business of the nature of the service being charged and the associated amount. The responsible individual or department making the direct charges to one of the affiliate entities should provide sufficiently detailed documentation of the charges (i.e. vouchers, invoices, payroll registers, etc.) such that the associated business can understand the nature and appropriateness of the charge. Additional information should be provided upon request.

Indirect Allocation of Costs

For certain business activities, it may be impractical to direct charge labor, supplies, or other costs because of the associated administrative burden to track such costs. In these situations, the costs related to a business activity may be accumulated and subsequently allocated based on a cost-causation allocation formula. In determining a reasonable and prudent allocation factor for these types of costs, such an allocation should consider the relative degree of utilization of the business activity by the respective entities. Examples of indirect allocation methods used are respective MWF allocations, net assets employed (“NAE”) allocation, employee headcount, unit count, etc. The ultimate objective is to achieve a proper sharing of costs among entities whereby costs assigned are commensurate with associated benefits.

Payroll Burden

Payroll burden includes fringe benefits such as medical, life and other insurance coverage, pension plan expense, employee savings plan participation, payroll taxes, and paid time off. Fringe benefits and paid time off are considered additions to the cost of company labor, which must be applied so that the full cost of labor is properly attributed to business activities and affiliates. These rates are charged in addition to labor rates when UGI Utilities charges labor to an affiliate. The rates for fringe benefits and paid time off are based upon the budgets for these costs in relation to budgeted company labor costs and are reviewed at least quarterly and adjusted as needed throughout the year to reflect actual fringe benefits, paid time off and labor incurred.

Use of UGI Utilities' Assets

In certain instances, the regulated businesses within UGI Utilities share common assets. Under such circumstances, the approach is to allocate the related costs such as depreciation and property taxes based upon respective MWF allocations. UGI Utilities utilizes MWF allocation rates to allocate costs amongst different businesses as necessary based on which businesses benefit from the asset. This is done so not to incorrectly allocate associated costs with businesses which are not receiving the benefits of using the related assets. See below for more detailed information as it relates to UGI Utilities' MWF calculations.

In addition, UGI Utilities may also share assets (such as office space), pursuant to affiliated interest agreements, with other non-regulated affiliates. Under such circumstances, the cost allocation approach should ensure that UGI Utilities' regulated utility operations are made whole by charging all costs related to the portion of the asset being used and for the entire period it is utilized by the affiliate. The charge to the affiliate should generally include an allocation of depreciation and other applicable costs related to the portion of the asset utilized for the period. In addition, any operating and maintenance costs related to the asset and incurred by UGI Utilities' operations during the affiliate's usage period should be captured and allocated, to the extent appropriate, to the unregulated affiliate.

If the usage of the asset by the non-regulated affiliate is anticipated to be for a prolonged period of time, consideration should be given to transferring the asset from UGI Utilities' regulated utility operations to the affiliate.

UGI Utilities Cost Allocation Methods

As noted above under "Indirect Allocation of Costs", UGI Utilities may use various cost allocation factors to share costs, depending on the business activity being provided and the entities receiving the benefit. The allocation factor should represent the relative degree of utilization of the business activity by the respective entities.

As part of final gas base rate case order issued October 4, 2019, the Pennsylvania Public Utility Commission ("PAPUC") approved a single tariff and combined rates for substantially all of the rate classes within the Company's existing gas rate districts (North, South and Central). This has substantially eliminated the need to track costs at the gas rate district level. However, because the consolidated rates did not take effect until after Fiscal Year 2020 had begun and because there are certain other residual reporting requirements related to the three former gas rate districts, the Company has maintained MWF allocations for the three gas rate districts as well as for Electric Utility for Fiscal Year 2020.

As part of the 2020 gas base rate settlement, all residual required gas rate district accounting should be eliminated, effective October 1, 2020. As a result, the current means of allocating common costs to the three former gas rate districts will be eliminated. Thus, all costs previously allocated to the former gas rate districts will be more simply assigned to the Gas Division.

The following are cost allocation factors used by UGI Utilities to allocate shared costs amongst its regulated businesses (Gas Utility and Electric Utility) or to non-regulated affiliates.

Modified Wisconsin Formula (MWF) allocations

UGI Utilities utilizes the its MWF allocation method, which measures the relative size and activity of each business, to allocate the majority of its shared costs.

Activity is measured by (1) total revenues and (2) total operating expenses excluding taxes other than income taxes, depreciation, and amortization (before UGI Corporate allocated costs). Revenue and expense amounts used in the MWF are from the previous fiscal year. Size, the third (3) component of the MWF, is measured by gross property, plant, and equipment from the previous fiscal year ended. Each of the three components described above receives an equal one-third (1/3) weighting in the MWF calculation. This equal weighting is then used to determine the overall percent to be applied to each respective business within UGI Utilities.

UGI Utilities' Modified Wisconsin Formula is an equitable, easily verifiable, consistently applied method of allocation and prevents the use of arbitrary judgments based on one-time events. UGI Utilities updates its respective MWF allocations at least annually. The Accounting department is responsible for calculating and approving the MWF allocation rates. The Accounting department also updates and maintains the rates in the Company's ERP system and communicates the rates to other departments, where applicable. The most recent UGI Utilities MWF calculations are attached as Appendix E.

Net Assets Employed (NAE) allocation

In some instances, UGI Utilities may allocate certain costs based on each respective businesses' net assets employed (NAE). NAE is defined as total assets, excluding cash, less total current liabilities, less total deferred liabilities. Intra-company account balances are included in the NAE calculation as each business is considered standalone for the purposes of the NAE calculation.

UGI Utilities' Net Assets Employed calculation is a reasonable and supportable method of allocation which is especially useful in allocating costs that are driven primarily by balance sheet amounts. The NAE allocation is easily updated and should be done so at least quarterly. The Accounting department is responsible for calculating, approving, and updating the NAE allocation factors in the Company's ERP system.

Other indirect allocation methods

UGI Utilities and its subsidiaries may allocate costs using other methods more specific to the business activity being performed, in order to assign the costs more accurately to be commensurate with the associated benefits. Examples of these allocation methods include, but are not limited to:

- Employee headcount – allocating costs associated with employee headcount based upon the number of employees at each business as a percentage of total employees related to the business activity being performed.
- Number of licenses – allocated costs associated with certain shared informational technology systems based on the number of licenses utilized by each business as a percentage of the total licenses.
- Unit or transaction counts – allocating costs associated with the number of respective units or transactions, based upon each business's measurable number of units or transactions as a percentage of the total for each business activity being performed.

The department which is most closely connected to the business activity being performed is responsible for maintaining the supporting data and providing the allocation factors to the Accounting department.

APPENDIX F – INDEX OF SERVICES ALLOCATED ON A COST BASIS WITHIN UGI UTILITIES BUSINESSES

The following is an index of services and related costs which are shared amongst various regulated businesses within UGI Utilities (Gas Utility and Electric Utility). Each identified service contains a general description as well as a discussion of the cost allocation procedures which will be followed for charging or allocating the respective costs to the various businesses.

Detailed records supporting the cost allocations to the affiliates are maintained by UGI Utilities. These summaries of services and related costs will be updated annually.

Use of Common Assets

To the extent multiple regulated businesses share common assets, the related costs such as depreciation, operations and maintenance expenses, property taxes, and property insurance, are allocated amongst the businesses using these assets using respective MWF allocations. UGI Utilities and its subsidiaries utilize MWF calculations to allocate costs amongst different businesses that are sharing the common assets. This is done so not to allocate associated costs to businesses not receiving the benefits of using the related assets.

Examples of these common assets include shared office buildings, leasehold improvements of shared leased facilities, office furniture, informational technology equipment and software.

The Accounting department is responsible for maintaining the supporting data and updating the respective allocations.

Occupancy Costs for Common Use of Leased Facilities

Gas Utility and Electric Utility lease and occupy facilities which are utilized by employees performing services attributable to multiple businesses (see “Intracompany Labor and Relate Burdens” below). The related occupancy costs are allocated to each applicable business using the respective MWF allocation, depending on which applicable businesses are utilizing the facility. Occupancy costs include rent, property taxes, maintenance, and other operations related expenses.

Intracompany Labor and Related Burdens

Due to the close interrelation of the regulated businesses and many of the Company’s employees (typically exempt employees) performing services attributable to multiple businesses, it is not administratively feasible to specifically measure each employees time allotted to each business. Thus, these employees’ time and related payroll and burden costs are allocated amongst the respective businesses by predetermining the allocation of each employees’ time, which is then automatically charged to each business based on the predetermined allocation.

Each supervisor is responsible for determining their respective employees’ time allocations when employees start new positions and communicating that with the Human Resources department, which then enters the allocation into the payroll system. As part of the performance of a key SOX Control, Vice Presidents are required to review each employee’s allocation annually to ensure that employees’ duties and responsibilities are properly reflected in their predetermined time allocations.

There may be instances where an employee who is specifically identified as one particular business's employee, works on a specific project for another business. In these cases, the employee's time is directly coded to the other business's project code. As a result, the employee's time and related payroll and burden costs are directly charged to the correct business. Employees' time is subject to review and approval by their supervisor for each pay period.

Information Technology Services

Certain information technology costs and the related benefits are attributable to multiple businesses. Examples of these costs include application and phone services, software license fees, third party support costs, and maintenance costs of electronic data processing (EDP) equipment. These costs are allocated to each applicable business using the respective MWF allocation, depending on which businesses are receiving the benefit from each individual service. The Information Services department is responsible for providing information to the Accounting department regarding which business activities apply to which business. The Accounting department is responsible for applying the appropriate MWF allocation and calculating the applicable cost to each business.

Insurance Services

UGI Utilities has numerous insurance policies for various types of coverage, which protect all businesses. These invoiced costs are allocated amongst the applicable businesses using the respective MWF allocation, depending on which applicable businesses are receiving the benefit from the insurance coverage. The Accounting department is responsible for applying the appropriate MWF allocation and calculating the applicable cost to each business.

Membership Dues

UGI Utilities pays various industry related membership dues which benefit multiple businesses. These invoiced costs are allocated amongst the applicable businesses using the respective MWF allocation, depending on which applicable businesses are receiving the benefit from the membership. The Accounting department is responsible for applying the appropriate MWF allocation and calculating the applicable cost to each business.

Office Supplies and Expenses

Whenever feasible, office supplies and general operating office expenses are charged directly to the applicable business. However, in many cases, direct charging is not practical. In these instances, these costs are allocated to each applicable business using the respective MWF allocation, depending on which applicable businesses are receiving the benefit from each individual cost. The Accounting department is responsible for applying the appropriate MWF allocation and calculating the applicable cost to each business.

Other Administrative and General Expenses

UGI Utilities cost allocations are not limited to those costs listed above. There are other instances where directly charging a business is not administratively feasible. In these instances, these costs are allocated to each applicable business using the respective MWF allocation.

APPENDIX G – INDEX OF UGI UTILITIES' SERVICES TO NON-REGULATED AFFILIATES

The following is an index of UGI Utilities services currently provided to non-PUC regulated affiliates and, where applicable, the method for determining cost assignment or allocation. Each identified service contains a general description as well as a discussion of the cost assignment or allocation procedures which will be followed for charging or allocating costs to the affiliates where there is not an alternative PUC-approved affiliated interest agreement methodology. When providing a service to a non-regulated affiliate, UGI Utilities follows the general principle of charging the greater of its incurred costs or market value for similar services, if applicable.

Detailed records supporting the cost allocations to the affiliates are maintained by UGI Utilities and its subsidiaries. These summaries of services and related costs are updated at least annually.

Please note that this list comprises services that UGI Utilities and its subsidiaries are currently providing to UGI Corporation, or other of its subsidiaries. This list could change, some services being discontinued, and potentially other services being added. Additionally, services provided by UGI Utilities are done so pursuant to the respective PUC-Affiliate Interest Agreement.

Occupancy Costs for Use of UGI Utilities Owned or Leased Assets

Non-regulated affiliates' employees utilize portions of assets owned or leased by UGI Utilities. To the extent affiliates jointly occupy a UGI Utilities or subsidiary-owned or leased facility, the cost to the affiliate is an allocation based on the relative square footage of the facility occupied by the affiliate. Occupancy costs include all the following which apply: operations and maintenance expenses (including rent), depreciation, property taxes, and property insurance. These costs are captured by location and are divided by the total square footage of the facility to arrive at the occupancy cost per square foot. Total square footage occupied by the affiliate is reviewed at least annually and more frequently if there are significant changes throughout the year.

For other assets which have no associated square footage, such as informational technology equipment and software, all costs related to those assets, such as operations and maintenance expenses (including lease payments), depreciation, and a pre-tax rate of return on UGI Utilities owned assets, are captured by asset or group of assets, and are allocated based upon usage of the asset(s). Allocation methods for these types of assets can include allocating costs by the estimated usage time of the asset by each affiliate, the number of respective units used by each affiliate, the number of associated transactions by each affiliate, or respective MWF allocation, if applicable. The allocation method which is both administratively feasible and most reasonably attributes costs is selected. Any allocation factor used to allocate these costs is reviewed and updated at least annually.

Each respective associated department is responsible for gathering the supporting data, calculating, and approving the cost per square foot and the respective allocation factor for the use of any UGI Utilities owned or leased assets by an affiliate. This information is sent to and maintained by the Accounting department for billing and accounting purposes.

Labor and Related Burdens

UGI Utilities and its subsidiary employees sometimes provide administrative, telemetry or other services to non-regulated affiliates on a cost or market basis. In the case of pipeline, engineering, construction, maintenance and related services, these services are provided at the higher of cost or market pursuant to a Commission-approved affiliated interest agreement. When allocated on the basis of cost, these employees' time and related payroll and burden costs are captured and charged to the respective affiliate in two general manners: 1) direct charge or 2) predetermined time.

There may be instances where a UGI Utilities employee works specifically on a project for an affiliate. In these cases, the employee's time is coded to the affiliate's project code. As a result, the employee's time and related payroll and overhead costs associated with that project are calculated and charged. As noted above, when providing services to non-regulated affiliates, UGI Utilities charges the greater of its incurred costs or market value for similar services unless otherwise authorized by a PUC-approved affiliated interest agreement.

In many cases, it is not administratively feasible to specifically measure each UGI employee's time allotted to each affiliate. Thus, these employees' time and related payroll and burden costs are allocated amongst UGI Utilities and each respective affiliate by predetermining the allocation of each UGI employee's time, which is then charged to each affiliate based on the predetermined calculation. In most of these cases, it is accepted by all parties that the calculated payroll and burden costs are equal to market value and that is what is charged to each affiliate. If any exceptions, an agreed upon market value is directly charged to the affiliate.

Each UGI Utilities supervisor of predetermined time employees is responsible for determining their respective employees' time allocations when employees start new positions and communicating that with the Human Resources department, which then enters the allocation into the payroll system. The predetermined allocations should be agreed upon by all relative parties and any changes should be communicated. As part of the performance of a key SOX control, UGI Utilities' Vice Presidents are required to review each employee's allocation annually to ensure that UGI Utilities' employees' level of service to affiliates is properly reflected in their predetermined time allocations. Any changes to services performed to affiliates or changes to the allocation factors of these services should be reflected in changes made to the respective employees' predetermined time.

Employee expenses incurred by UGI Utilities while performing services for other affiliates are charged directly to the affiliates as incurred.

See below for services that UGI Utilities is providing to non-regulated affiliates.

Natural Gas Business Activities

Several former UGI Utilities employees (primarily executives) serve in their preexisting roles overseeing their respective areas for all the Natural Gas businesses (UGI Utilities and UGI Energy Services, LLC) of UGI Corporation. These employees are employed and paid by UGI Corporation. See Appendix B for current listing of these Natural Gas employees and applicable allocation methodologies of their costs to each business unit. Some of these Natural Gas executives directly supervise and oversee UGI Utilities employees, activities, and services that benefit UGI Utilities and non-regulated affiliates, including:

- **Human Resources**
  - *Payroll and HR Services*

    UGI Utilities processes payroll and administers HR services for non-regulated affiliates' employees. The associated payroll and burden costs of UGI Utilities' HR department employees is allocated to each respective affiliate based upon each employee's predetermined time, as described above in "Labor and Related Burdens". Predetermined time for HR department employees is allocated based on employee headcount of each affiliate utilizing UGI Utilities' payroll processing and HR services.

    Third party payroll and benefit provider costs, which are directly billed to UGI Utilities, are allocated to the respective affiliates based on the total employee headcount of each affiliate utilizing UGI Utilities' payroll processing and HR services.

    Affiliate employees' payroll withholdings and affiliate contributions, such as insurance premiums, flexible spending account (FSA), Political Action Committee (PAC), and retirement plan contributions, are remitted directly to the third party by UGI Utilities. This also includes affiliate employees' payroll withholdings towards purchases through the affiliate, which are remitted by UGI Utilities to the respective affiliate. UGI Utilities identifies and segregates all affiliate withholdings and contributions and direct charges these costs to the affiliates.

    The HR department is responsible for the supporting data and calculations of these allocations.

- **Information Technology**

  UGI Utilities provides support of a general nature to other affiliates, including access security, infrastructure, application support, operational and disaster recovery services, and participation in corporate special projects. The associated payroll and burden costs of UGI Utilities' IT department employees is allocated to each respective affiliate based upon each employee's predetermined time, as described above in "Labor and Related Burdens". Predetermined time for IT department employees is allocated based on various methodologies, dependent on the applications being supported or services being provided, and which affiliates utilize those.

  Third party costs (such as support, maintenance, etc.) which are directly billed to UGI Utilities, are allocated to the respective affiliates based on various methodologies, dependent on the applications being supported or services being provided, and which affiliates utilize those.

  UGI Utilities' IT department incurs and allocates costs based on three categories:

  - Direct – costs that are solely related to UGI Utilities or a non-regulated affiliate
  - Common – costs related to services and support that are available to all employees of the business units utilizing the service
  - Shared – contains components, each of which have a distinct cost allocation factor, such as number or users utilizing a particular service or application

  The IT department is responsible for determining and approving these charges and providing the information to the Accounting department for billing.

- **Communications & Community Relations**

  UGI Utilities provides support of a general nature to other affiliates, including the preparation of communications and participation in corporate special projects. The associated payroll and burden costs of UGI Utilities' Communications department employees is allocated to each respective affiliate based upon each employee's predetermined time, as described above in "Labor and Related Burdens".

Office, Courier, and General Services

UGI Utilities provides support of a general nature to other affiliates, including mailing services for several affiliates and participation in corporate special projects.

The associated payroll and burden costs of UGI Utilities' Office Services department employees are allocated to each respective affiliate based upon each employee's predetermined time, as described above in "Labor and Related Burdens".

All postage charges related to an affiliate's activities are captured separately by the Office Services department, provided to the Accounting department, and directly charged to the affiliate.

Office supplies and other similar purchases are charged directly to the corresponding affiliate. The department making the purchase is responsible for identifying affiliates' items and providing that information to the Accounting department for billing.

Courier expenses for UGI Utilities and several affiliates are billed in full to UGI Utilities. These expenses are allocated and charged based on the estimated service usage of each respective affiliate. This allocation is reviewed at least annually and adjusted as needed by the Office Services department. The allocation is provided to the Accounting department for entry into accounting application.

The Company's annual picnic for employees is shared with affiliates' employees. The associated costs, which are directly billed to UGI Utilities, are then allocated and billed to the respective affiliates based on the number of employees attending from each affiliate.

Pension and Other Postretirement Benefits

UGI Utilities sponsors a pension plan, a supplemental executive retirement plan (SERP), and other postretirement plans providing health care benefits to retirees. These plans benefit certain current and former employees of both UGI Utilities and other affiliates. Based on information provided by a third-party actuary, UGI Utilities performs the accounting for these retirement plans for all impacted entities. In doing so, UGI Utilities allocates a portion of related expense to each respective affiliate. The annual expense amounts are allocated and determined by the actuary, based upon the performance obligations of each affiliates' respective employees and retirees of each plan. UGI Utilities charges each affiliate monthly based on the expense allocations provided by the actuary.

Engineering Services

From time to time, UGI Utilities may provide operation, maintenance, and repair services, including emergency call center services, for a certain affiliate in association with the affiliate's natural gas pipeline facilities and regulation stations at locations within the services territories of UGI Utilities. These services include both routine and emergency services, as further described in separate agreements between UGI Utilities and the affiliate.

UGI Utilities charges the affiliate for these services on a market basis. Costs include direct labor at standard billing rates, travel expense, materials, equipment, and other direct costs plus any overheads. UGI Utilities is also reimbursed for all expenses incurred in utilizing third-party contractors.

UGI Utilities also provides certain environmental remediation services to certain affiliates. The costs of external parties that perform these services are billed to the affiliate. UGI Utilities' internal labor for the environmental remediation services should be direct charged and billed to the affiliate.

Gas Control Support Services

As part of UGI Central Gas Control, LLC ("UGI Gas Control") providing gas control services to UGI Utilities (see Appendix H), UGI Utilities has provided certain support services, including SCADA (software licensing and hosting/support services) and non-SCADA services (for miscellaneous software and support services). These services are required for UGI Gas Control to maintain its ability to perform its gas control functions. UGI Utilities directly charges UGI Gas Control based on actual expenditures incurred to perform these services. See separate affiliate interest agreement and related memo for specifics surrounding this arrangement.

See Appendix H for the allocation of services and costs from affiliates to UGI Utilities.

APPENDIX H – INDEX OF NON-PUC REGULATED AFFILIATES' SERVICES TO UGI UTILITIES

The following is an index of services potentially provided from non-regulated affiliates to UGI Utilities. Each identified service contains a general description as well as a discussion of the cost allocation procedures which will be followed for charging or allocating costs from the affiliates. Except where another method is authorized or required by the PUC-approved affiliated interest agreement, when receiving a service from a non-regulated affiliate, UGI Utilities is charged the lesser of the affiliate's incurred costs or market value for similar services, if applicable.

Detailed records supporting the affiliates' cost allocations are maintained by UGI Utilities. These summaries of services and related costs will be updated annually.

Please note that this list comprises services that affiliates other than UGI Corporation are currently providing UGI Utilities. UGI Corporation services provided to UGI Utilities are included in UGI Corporations CAM in Appendix B. This list could change, some services being discontinued and potentially, other services being added. Additionally, services provided by UGI Utilities' affiliates are done so pursuant to the respective Affiliate Interest Agreement where applicable.

Materials and Other Purchases

All materials, equipment, or other purchases such as contractor services made by affiliates, which are specifically identified to benefit UGI Utilities, are directly charged to UGI Utilities at cost.

Leasing of Office Space

To the extend UGI Utilities occupies a portion of a non-regulated affiliate owned or leased facility, the lower of cost or market is charged to UGI Utilities. Occupancy costs include all the following which apply: operations and maintenance expenses (including rent), depreciation, property taxes, and property insurance.

Gas Control Services

UGI Gas Control performs gas control services (monitoring and responding to UGI Utilities' Distribution System Signals and Alarms) These costs for these services are allocated and charged from UGI Gas Control to UGI Utilities by way of a percentage share of actual costs based on the annual number of signals and alarms that UGI Gas Control will receive for each respective company. See separate affiliate interest agreement and related memo for specifics surrounding this arrangement.

NRG Exhibit CR-3

Confidential

NRG-I-2

Request:

Please reference the Commission's Standards of Conduct applicable to natural gas distribution companies ("NGDCs") and NGSs at 52 Pa. Code § 62.142. How do the Company's practices ensure compliance with the provision that prohibits an NGDC from giving its affiliated NGS preference over other NGSs with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, nondelivery and other services provided to its affiliated NGS? 52 Pa. Code § 62.142(a)(2).

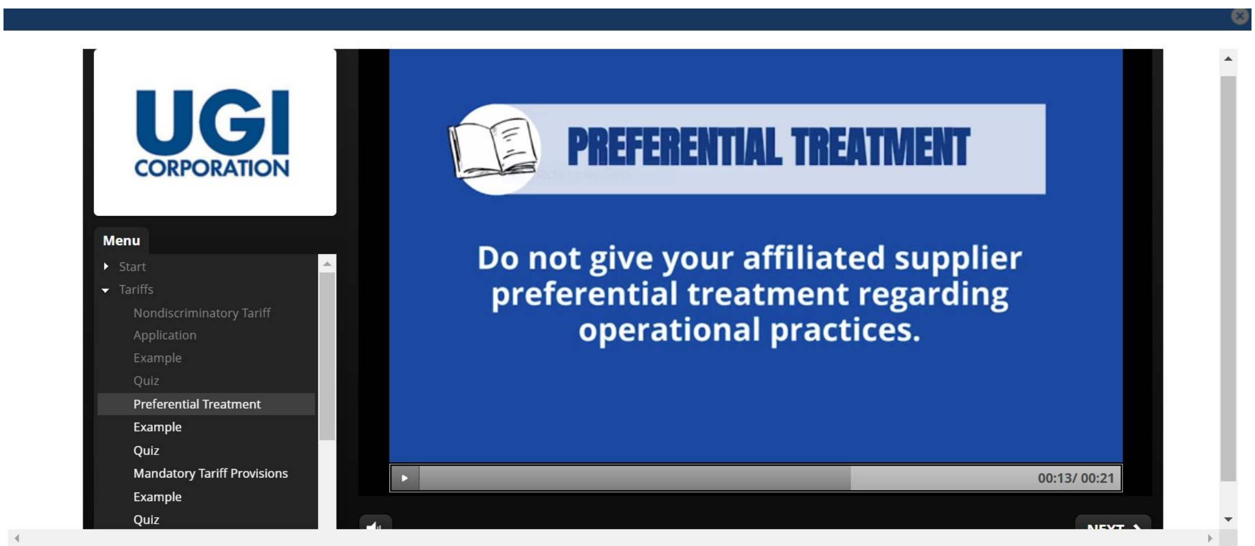
Response:

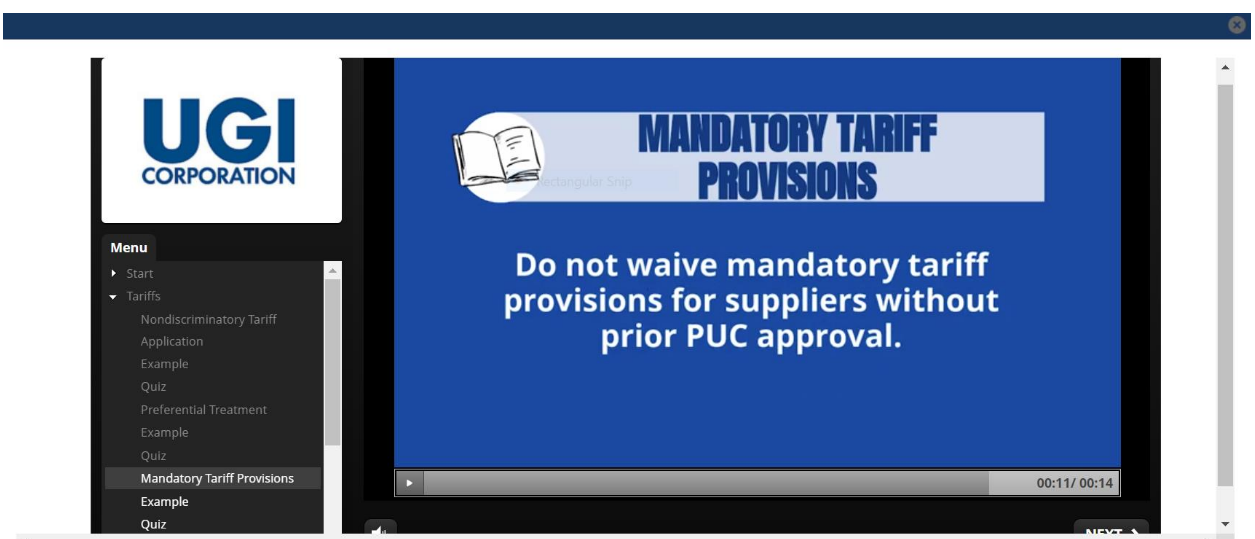
The Company embraces the Commission's Standard of Conduct through a training program designed to ensure compliance with the cited regulatory standards. In the case of the Capacity Lease, the lease was negotiated in the context of UGI-ES's role of a midstream infrastructure owner and not as a retail service provider. Moreover, the Capacity Lease was filed at Docket No. G-2021-3028753 and approved by the Commission's Secretarial Letter dated November 22, 2021. By way of additional response, please see CONFIDENTIAL Attachment NRG-I-2(a) and CONFIDENTIAL Attachment NRG-I-2(b) for hardcopies of the Company's most recent electronic training materials related to compliance with the Standards of Conduct.

THIS RESPONSE IS CONFIDENTIAL AND SHALL BE RELEASED TO PARTIES WHICH HAVE EXECUTED THE STIPULATED PROTECTIVE AGREEMENT OR IN ACCORDANCE WITH A PROTECTIVE ORDER.

Prepared by or under the supervision of: Christopher R. Brown

UGI UTILITIES, INC – GAS DIVISION
CODE OF CONDUCT VIDEO SCREENING



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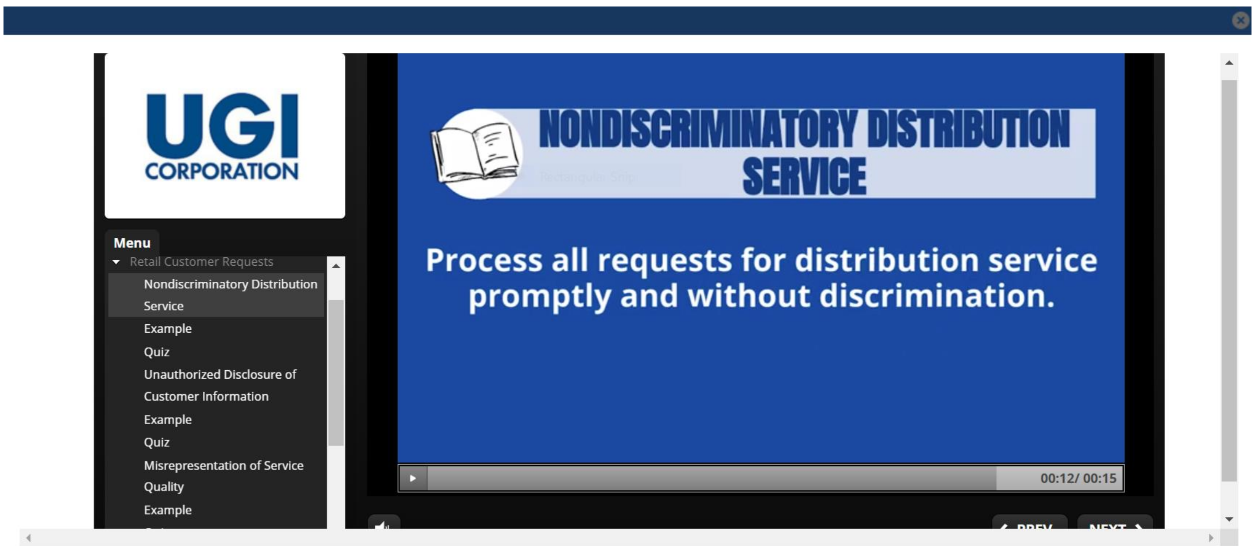
Tariffs
Nondiscriminatory Tariff Application
Example
Quiz
Preferential Treatment
Example
Quiz
Mandatory Tariff Provisions
Example
Quiz
TARIFF WAIVERS
Apply tariff waivers, service discounts, fee waivers or rebates equally to all suppliers and keep a transaction log.
00:14/ 00:19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Retail Customer Requests
Nondiscriminatory Distribution Service
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Unauthorized Disclosure of Customer Information
Example
Quiz
Misrepresentation of Service Quality
Example
NONDISCRIMINATORY DISTRIBUTION SERVICE
Process all requests for distribution service promptly and without discrimination.
00:12/ 00:15


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Retail Customer Requests
Nondiscriminatory Distribution Service
Example
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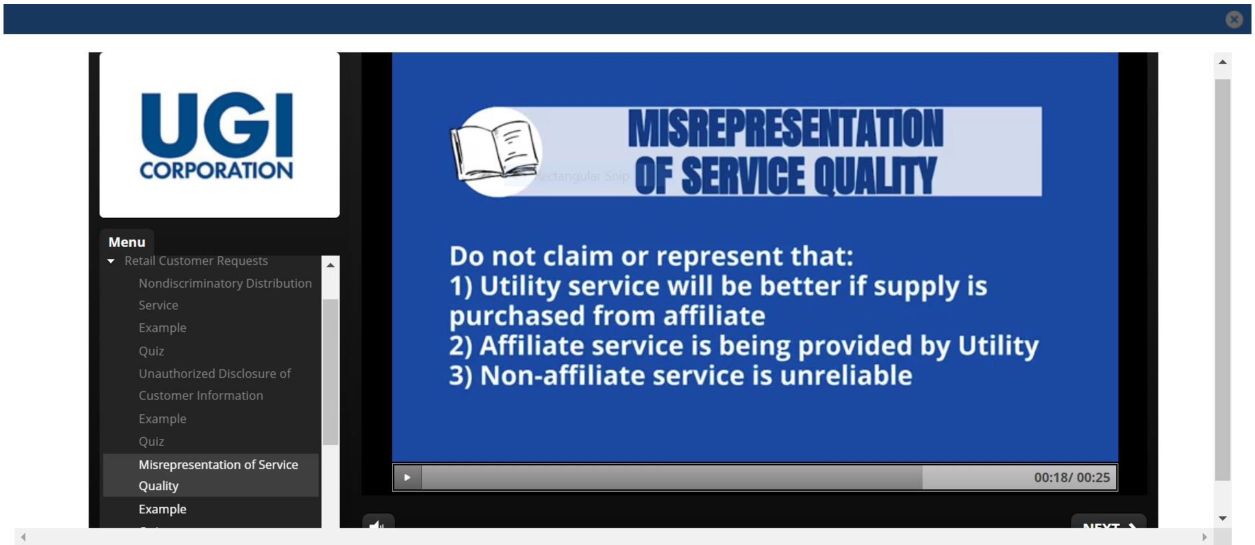
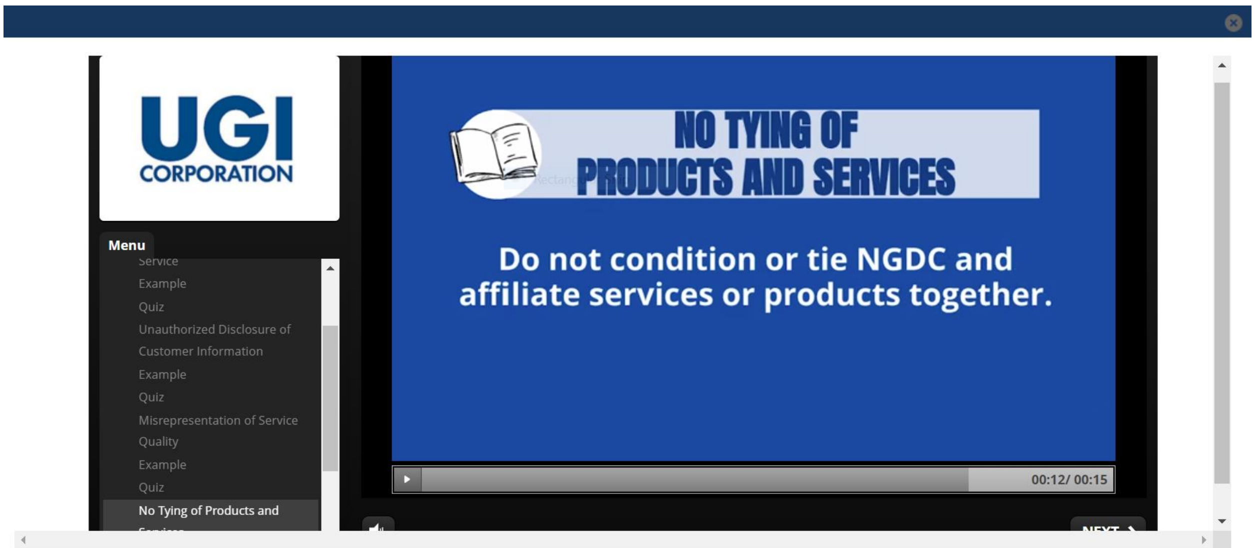
Unauthorized Disclosure of Customer Information
Example
Quiz
Misrepresentation of Service Quality
Example
UNAUTHORIZED DISCLOSURE OF CUSTOMER INFORMATION
Do not disclose private customer information to the affiliate absent customer authorization.
00:13/ 00:17


UGI
CORPORATION
Menu
Retail Customer Requests
Nondiscriminatory Distribution
Service
Example
Quiz
Unauthorized Disclosure of
Customer Information
Example
Quiz
Misrepresentation of Service
Quality
Example
MISREPRESENTATION
OF SERVICE QUALITY
Do not claim or represent that:
1) Utility service will be better if supply is purchased from affiliate
2) Affiliate service is being provided by Utility
3) Non-affiliate service is unreliable
00:18/ 00:25


UGI
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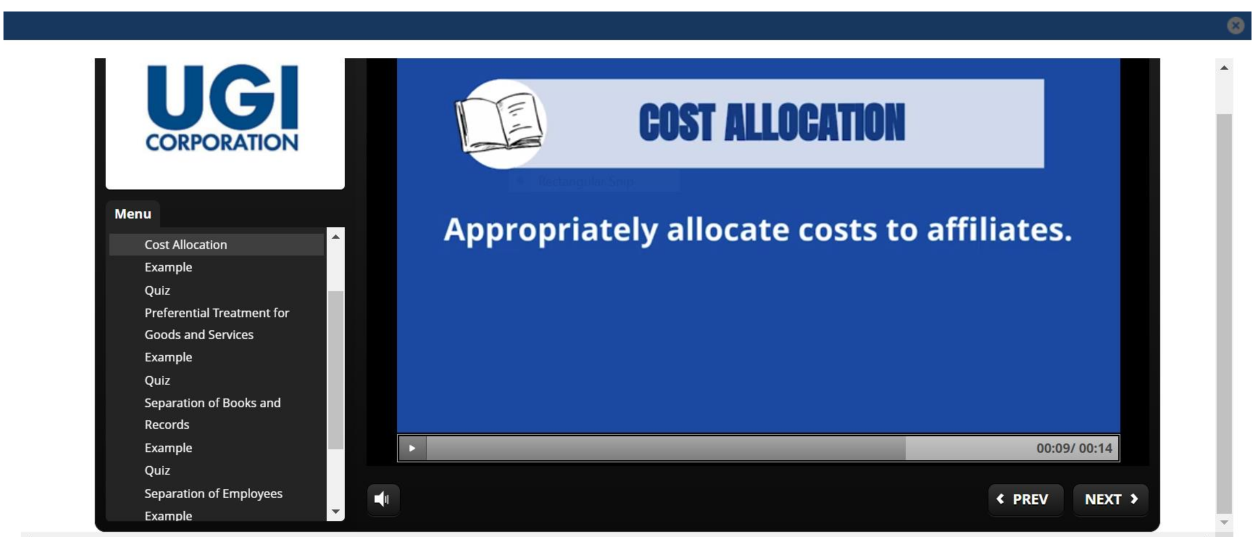
Menu
Example
Quiz
Unauthorized Disclosure of
Customer Information
Example
Quiz
Misrepresentation of Service
Quality
Example
Quiz
No Tying of Products and
NO TYING OF
PRODUCTS AND SERVICES
Do not condition or tie NGDC and affiliate services or products together.
00:12/ 00:15


UGI
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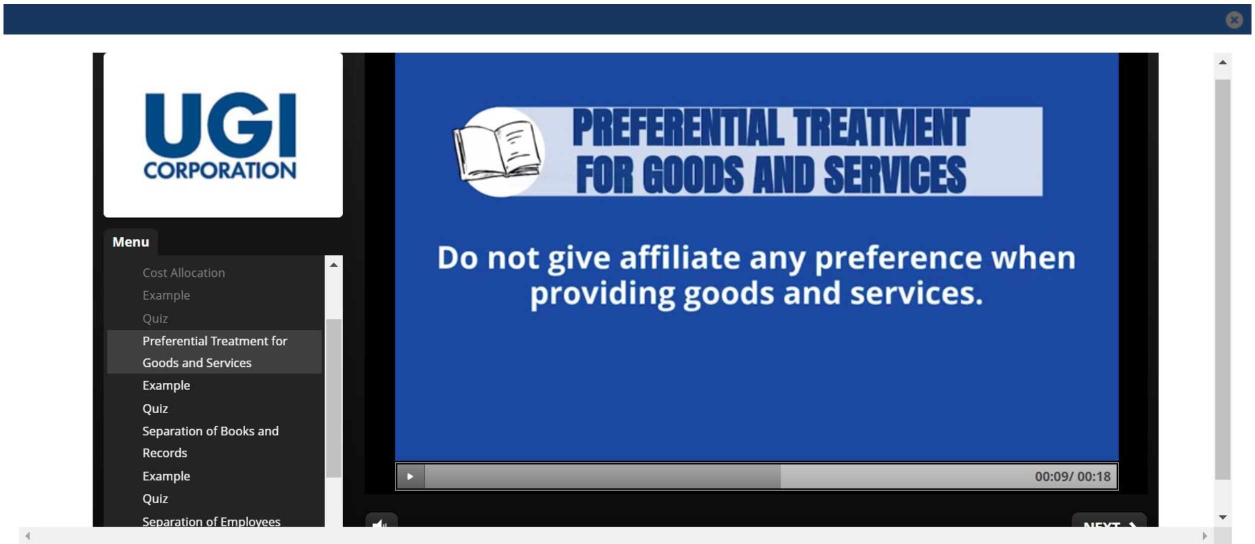
Cost Allocation
Example
Quiz
Preferential Treatment for
Goods and Services
Example
Quiz
Separation of Books and
Records
Example
Quiz
Separation of Employees
Example
COST ALLOCATION
Appropriately allocate costs to affiliates.
00:09/ 00:14
PREV
NEXT


UGI
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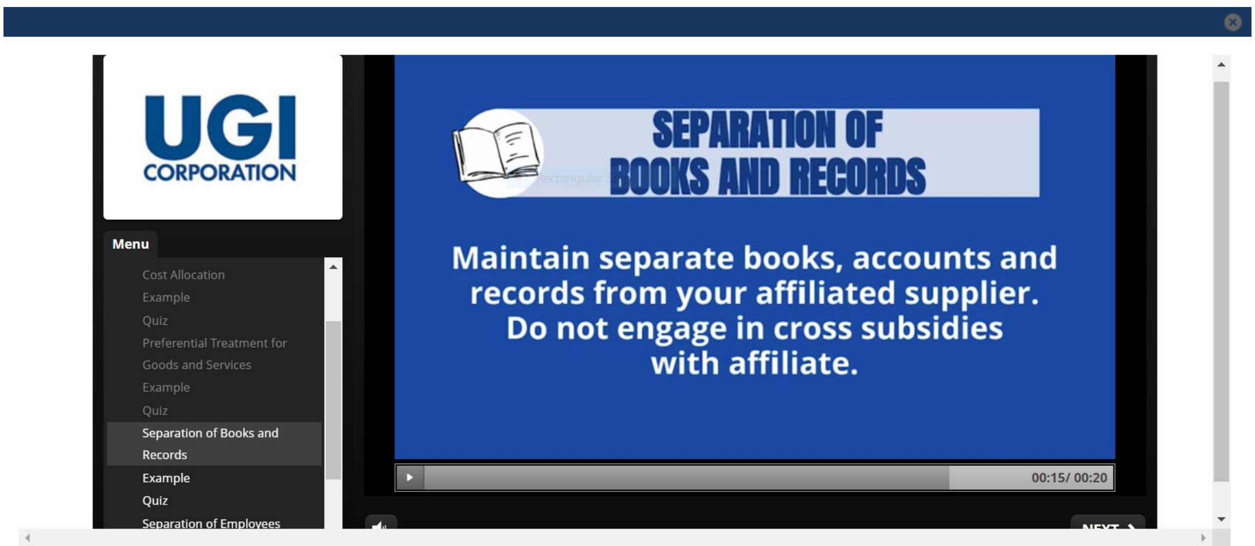
Cost Allocation
Example
Quiz
Preferential Treatment for
Goods and Services
Example
Quiz
Separation of Books and
Records
Example
Quiz
Separation of Employees
PREFERENTIAL TREATMENT
FOR GOODS AND SERVICES
Do not give affiliate any preference when
providing goods and services.
00:09/ 00:18


UGI
CORPORATION
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Cost Allocation
Example
Quiz
Preferential Treatment for
Goods and Services
Example
Quiz
Separation of Books and
Records
Example
Quiz
Separation of Employees
SEPARATION OF
BOOKS AND RECORDS
Maintain separate books, accounts and
records from your affiliated supplier.
Do not engage in cross subsidies
with affiliate.
00:15/ 00:20


UGI
CORPORATION
Menu
Cost Allocation
Example
Quiz
Preferential Treatment for
Goods and Services
Example
Quiz
Separation of Books and
Records
Example
Quiz
Separation of Employees
SEPARATION OF EMPLOYEES
Do not share NGDC employees with an
affiliate if the employees are responsible
for operations, marketing and customer
service functions. These employees also
must be physically separated from UGIES
offices.
00:17/ 00:34


UGI CORPORATION
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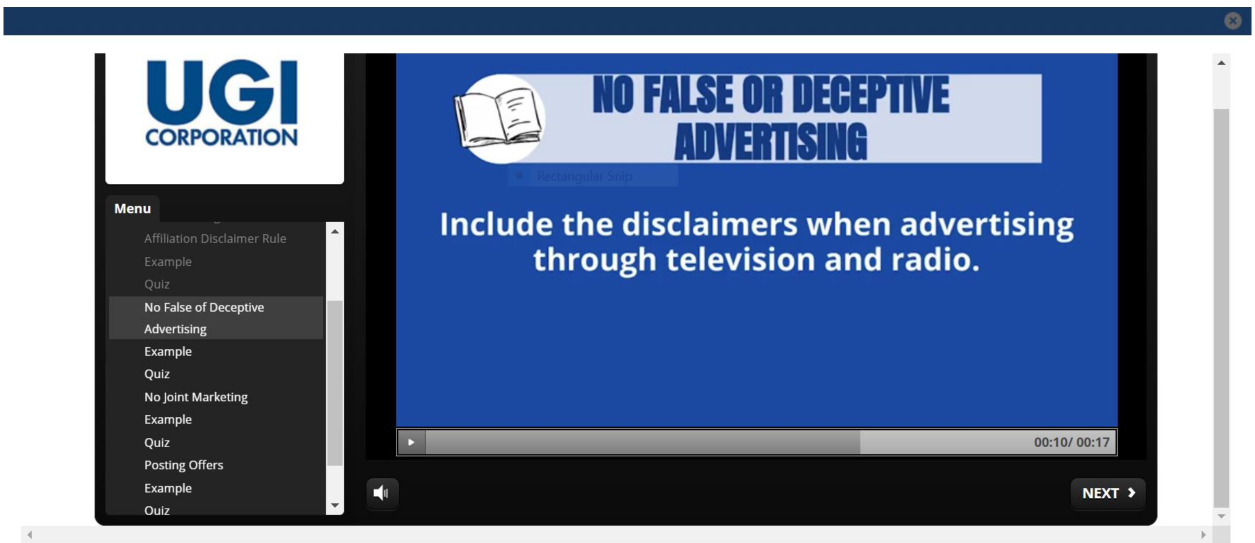
Affiliation Disclaimer Rule
Example
Quiz
No False of Deceptive
Advertising
Example
Quiz
No Joint Marketing
Example
Quiz
Posting Offers
Example
AFFILIATION DISCLAIMER
Market or communicate to the public with a disclaimer:
1) The affiliated NGS is not the same company as the NGDC
2) NGS' prices are not regulated by the PUC
3) Customers don't have to contract with the affiliate to receive quality service from the NGDC
00:11/ 00:35


UGI CORPORATION
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Affiliation Disclaimer Rule
Example
Quiz
No False of Deceptive
Advertising
Example
Quiz
No Joint Marketing
Example
Quiz
Posting Offers
Example
Quiz
NO FALSE OR DECEPTIVE ADVERTISING
Include the disclaimers when advertising through television and radio.
00:10/ 00:17
NEXT


UGI CORPORATION
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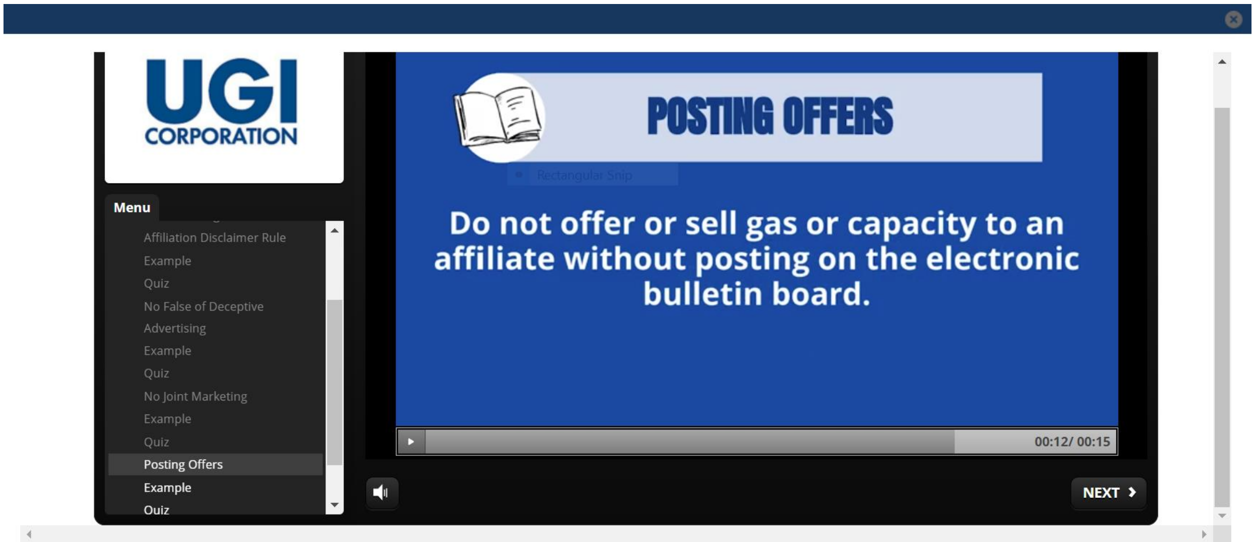
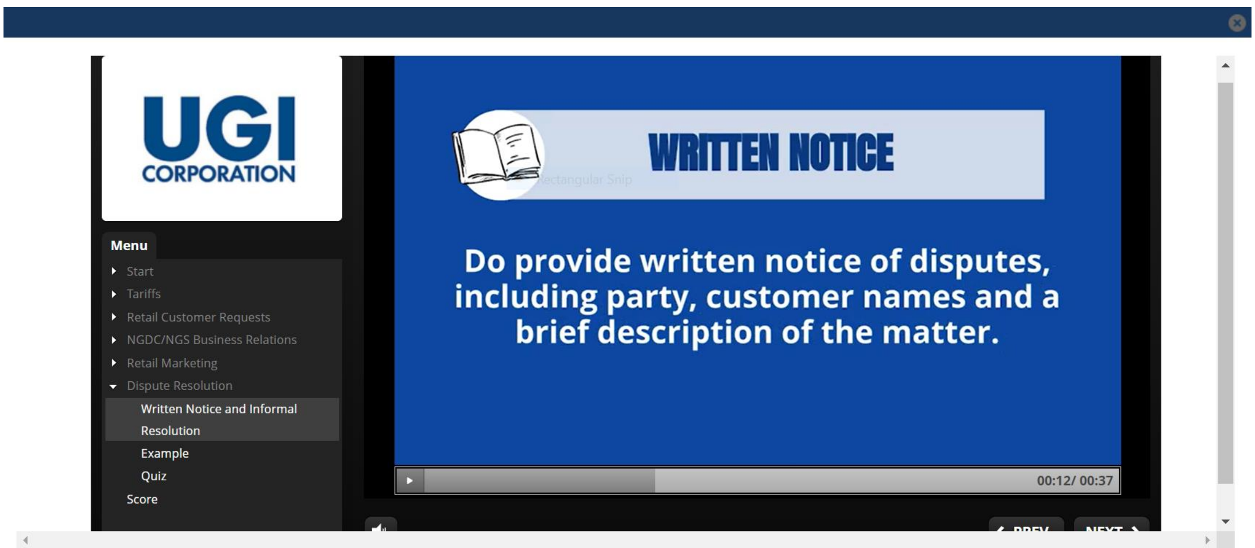
Affiliation Disclaimer Rule
Example
Quiz
No False of Deceptive
Advertising
Example
Quiz
No Joint Marketing
Example
Quiz
Posting Offers
Example
NO JOINT MARKETING
Do not market or package regulated (NGDC) and unregulated (Affiliated NGS) services together or offer marketing services only to affiliates.
00:16/ 00:21


UGI
CORPORATION
Menu
Affiliation Disclaimer Rule
Example
Quiz
No False of Deceptive
Advertising
Example
Quiz
No Joint Marketing
Example
Quiz
Posting Offers
Example
Quiz
POSTING OFFERS
Do not offer or sell gas or capacity to an affiliate without posting on the electronic bulletin board.
00:12/ 00:15
NEXT


UGI
CORPORATION
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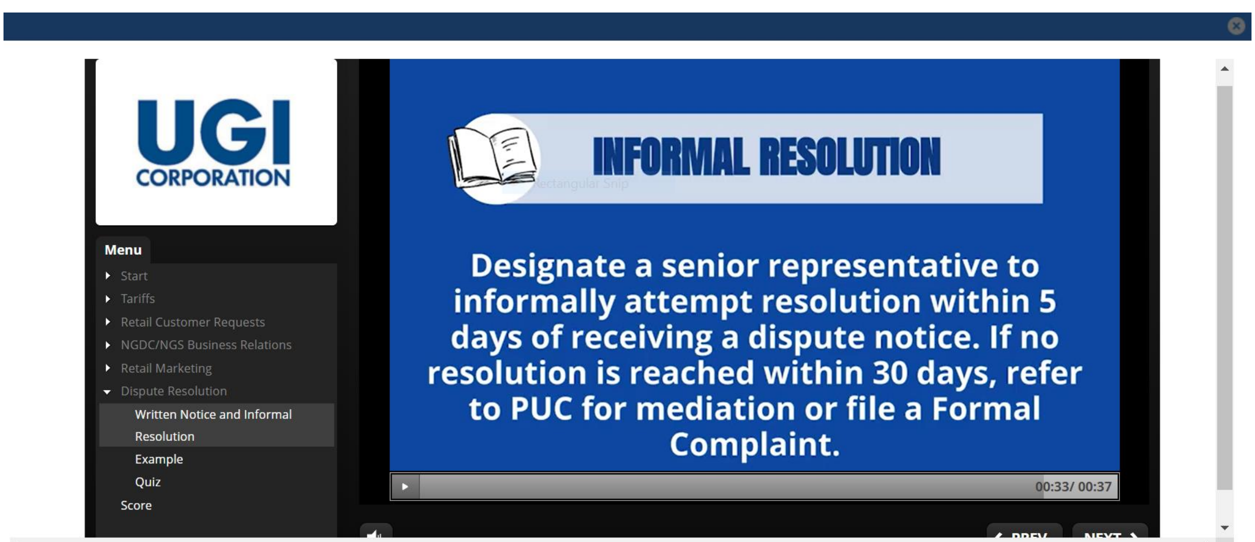
Start
Tariffs
Retail Customer Requests
NGDC/NGS Business Relations
Retail Marketing
Dispute Resolution
Written Notice and Informal
Resolution
Example
Quiz
Score
WRITTEN NOTICE
Do provide written notice of disputes, including party, customer names and a brief description of the matter.
00:12/ 00:37


UGI
CORPORATION
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Start
Tariffs
Retail Customer Requests
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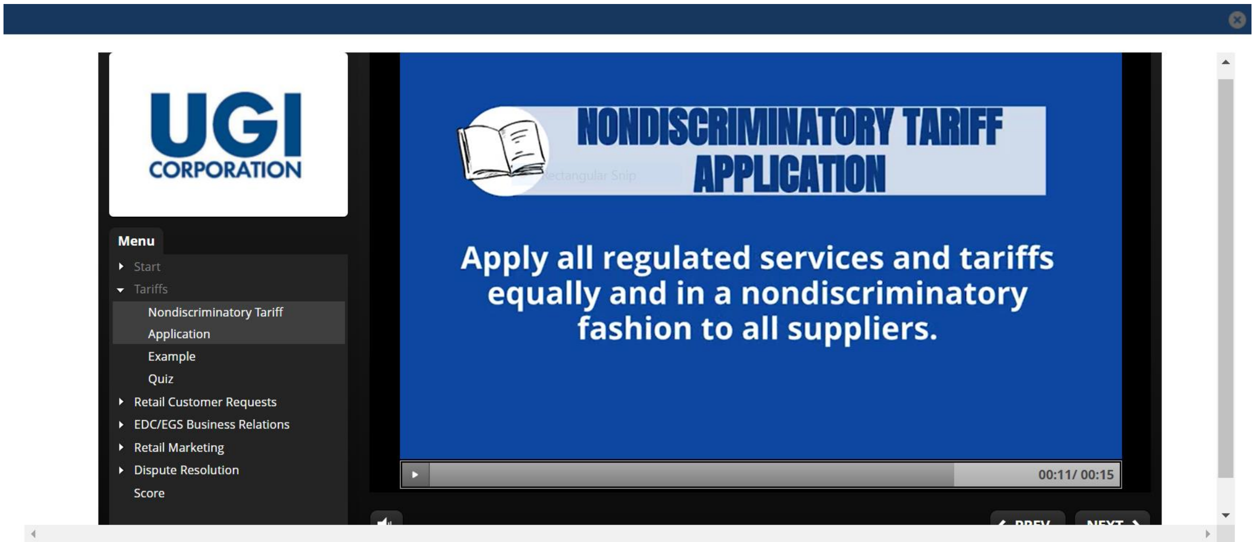
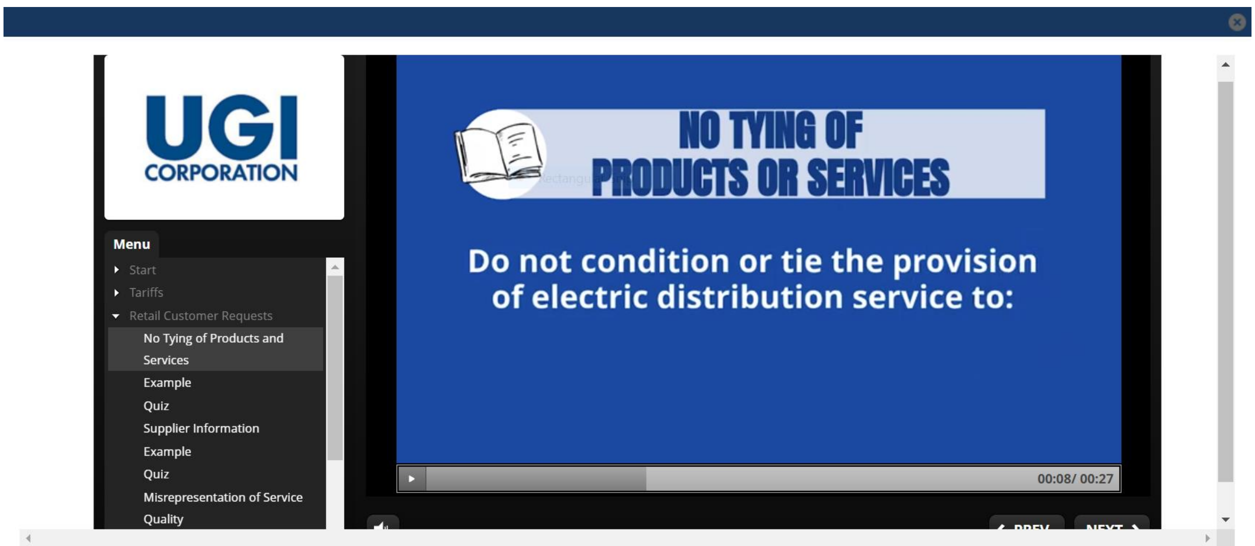
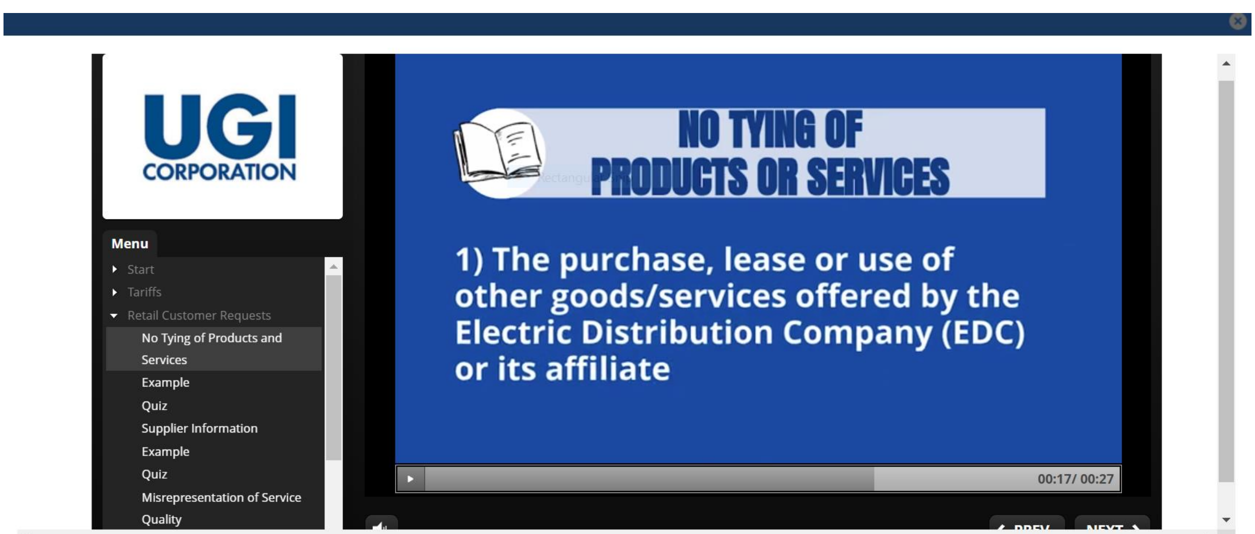
Retail Marketing
Dispute Resolution
Written Notice and Informal
Resolution
Example
Quiz
Score
INFORMAL RESOLUTION
Designate a senior representative to informally attempt resolution within 5 days of receiving a dispute notice. If no resolution is reached within 30 days, refer to PUC for mediation or file a Formal Complaint.
00:33/ 00:37

UGI UTILITIES, INC. – ELECTRIC DIVISION
CODE OF CONDUCT VIDEO SCREENING








UGI CORPORATION
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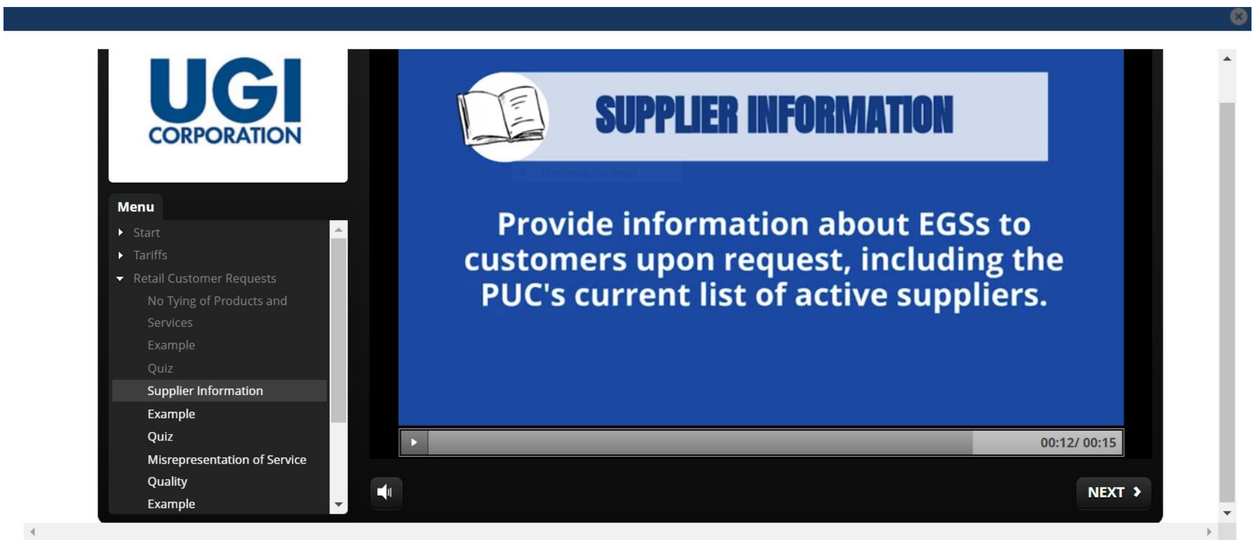
Start
Tariffs
Retail Customer Requests
No Tying of Products and Services
Example
Quiz
Supplier Information
Example
Quiz
Misrepresentation of Service Quality
NO TYING OF PRODUCTS OR SERVICES
2) A commitment not to deal with an alternative electric supplier
00:24/ 00:27


UGI CORPORATION
Menu
Start
Tariffs
Retail Customer Requests
No Tying of Products and Services
Example
Quiz
Supplier Information
Example
Quiz
Misrepresentation of Service Quality
Example
SUPPLIER INFORMATION
Provide information about EGSs to customers upon request, including the PUC's current list of active suppliers.
00:12/ 00:15
NEXT


UGI CORPORATION
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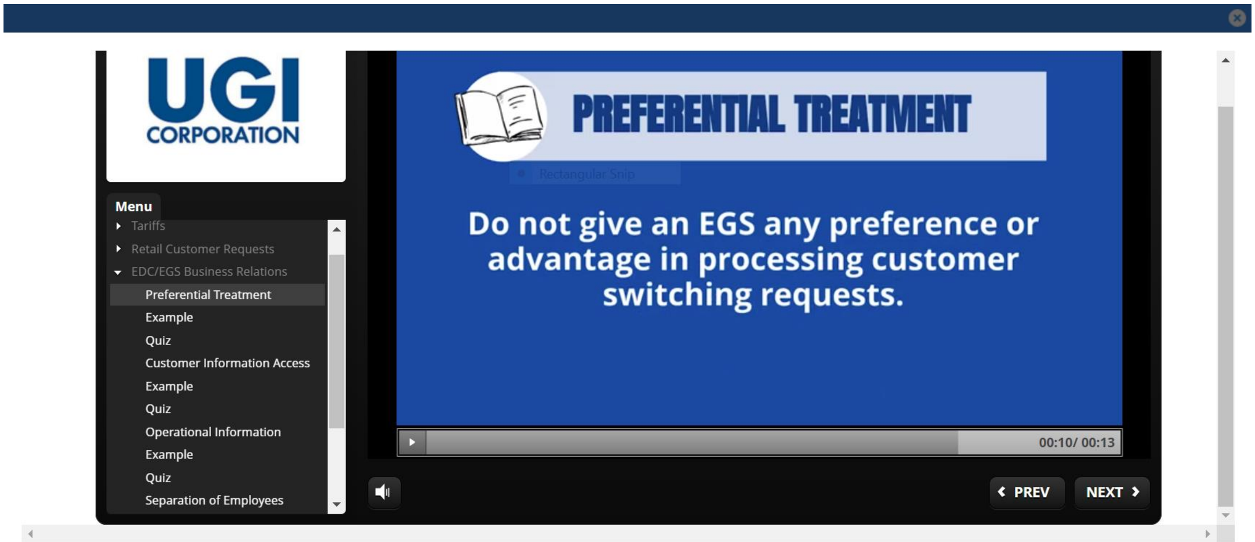
Start
Tariffs
Retail Customer Requests
No Tying of Products and Services
Example
Quiz
Supplier Information
Example
Quiz
Misrepresentation of Service Quality
MISREPRESENTATION OF SERVICE QUALITY
Do not state or imply that:
1) An EGS's services are superior because of an EDC affiliation
2) A customer will receive enhanced distribution service, if they purchase supply from an affiliate
00:18/ 00:22


UGI
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Tariffs
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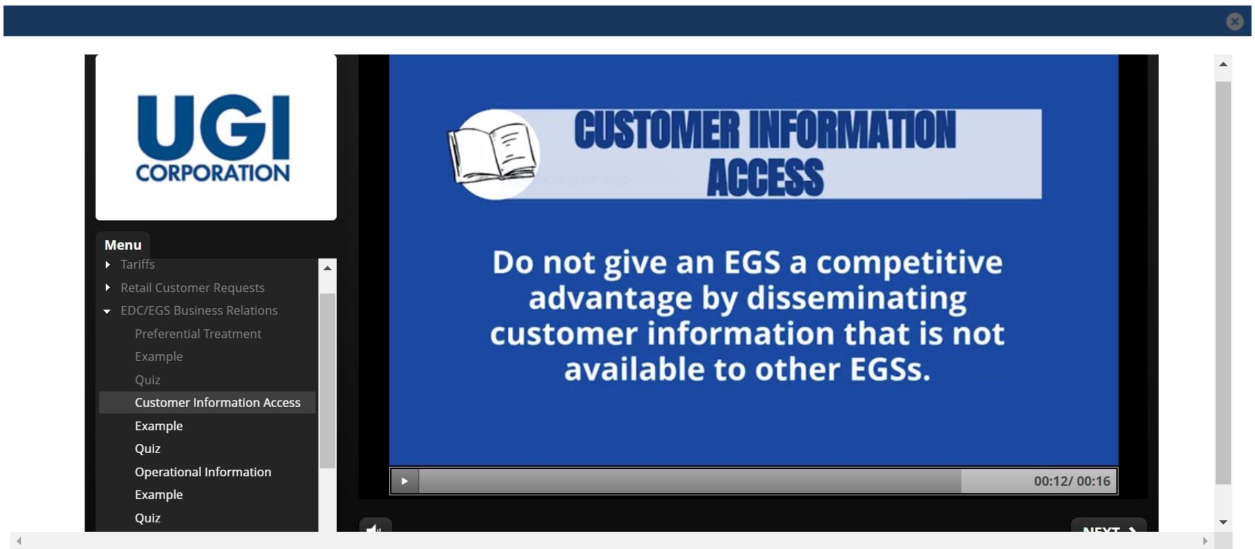
EDC/EGS Business Relations
Preferential Treatment
Example
Quiz
Customer Information Access
Example
Quiz
Operational Information
Example
Quiz
Separation of Employees
PREFERENTIAL TREATMENT
Do not give an EGS any preference or advantage in processing customer switching requests.
00:10/ 00:13
PREV
NEXT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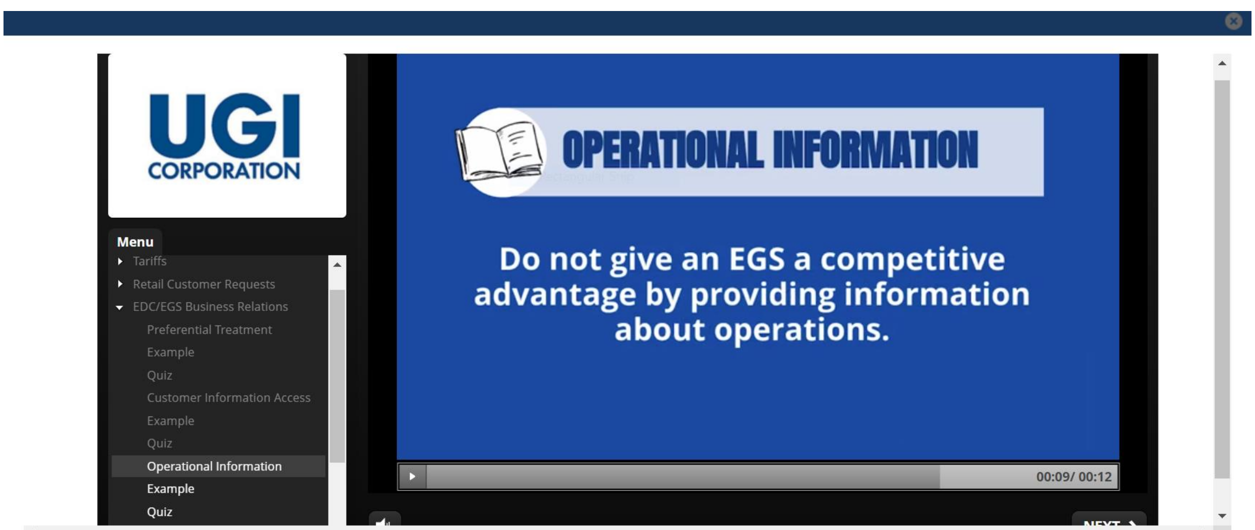
EDC/EGS Business Relations
Preferential Treatment
Example
Quiz
Customer Information Access
Example
Quiz
Operational Information
Example
Quiz
CUSTOMER INFORMATION ACCESS
Do not give an EGS a competitive advantage by disseminating customer information that is not available to other EGSs.
00:12/ 00:16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Tariffs
Retail Customer Requests
EDC/EGS Business Relations
Preferential Treatment
Example
Quiz
Customer Information Access
Example
Quiz
Operational Information
Example
Quiz
OPERATIONAL INFORMATION
Do not give an EGS a competitive advantage by providing information about operations.
00:09/ 00:12


UGI
CORPORATION
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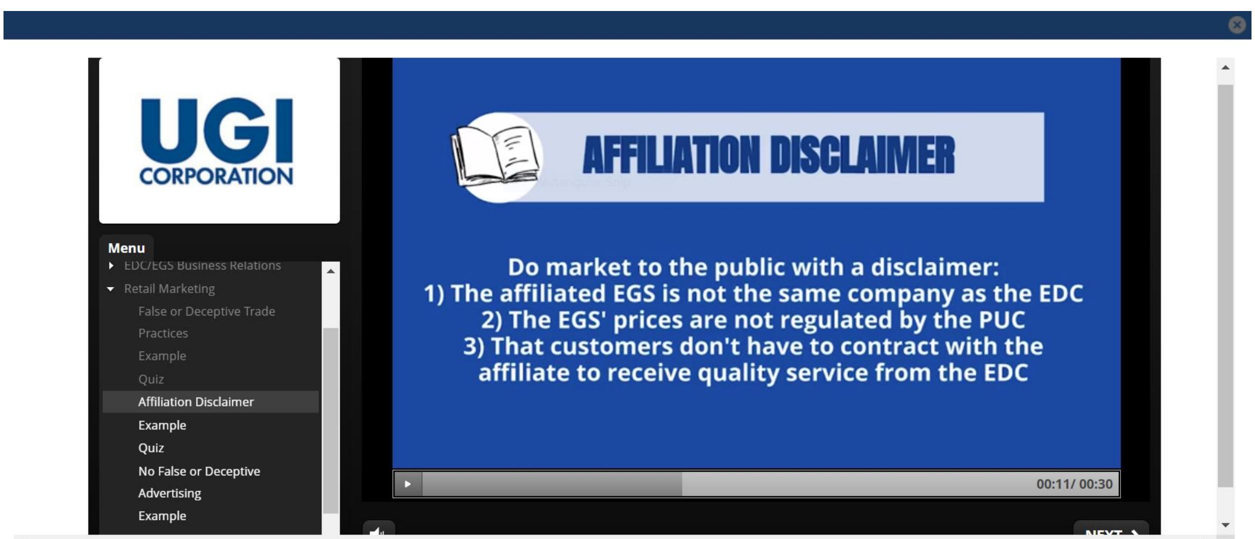
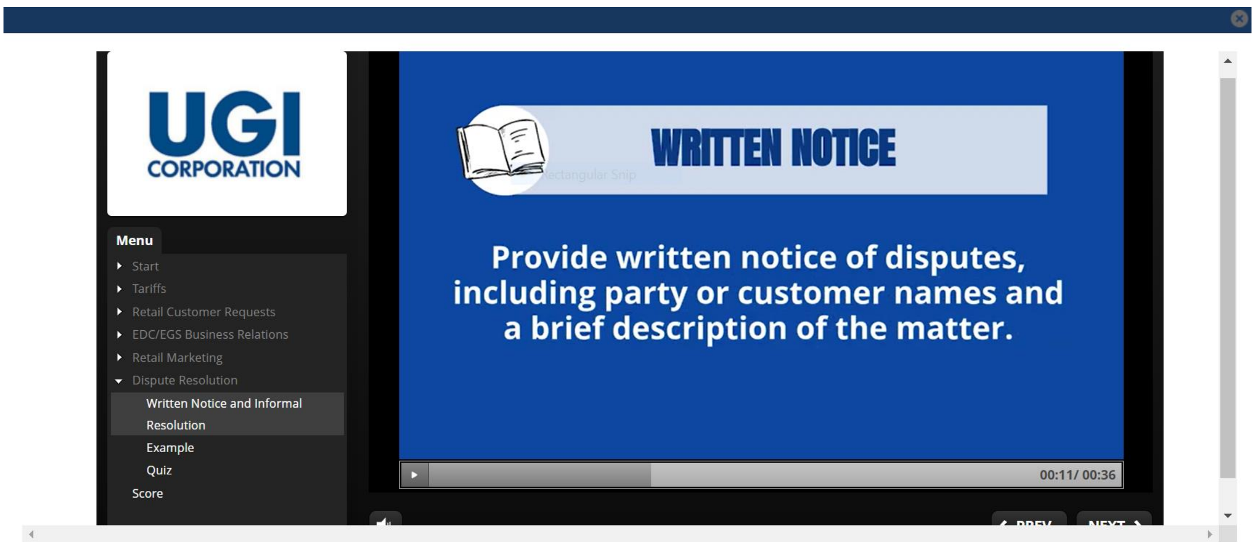
Tariffs
Retail Customer Requests
EDC/EGS Business Relations
Preferential Treatment
Example
Quiz
Customer Information Access
Example
Quiz
Operational Information
Example
Quiz
SEPARATION OF EMPLOYEES
Ensure that EGS and EDC employees function independently of each other.
00:08/ 00:12

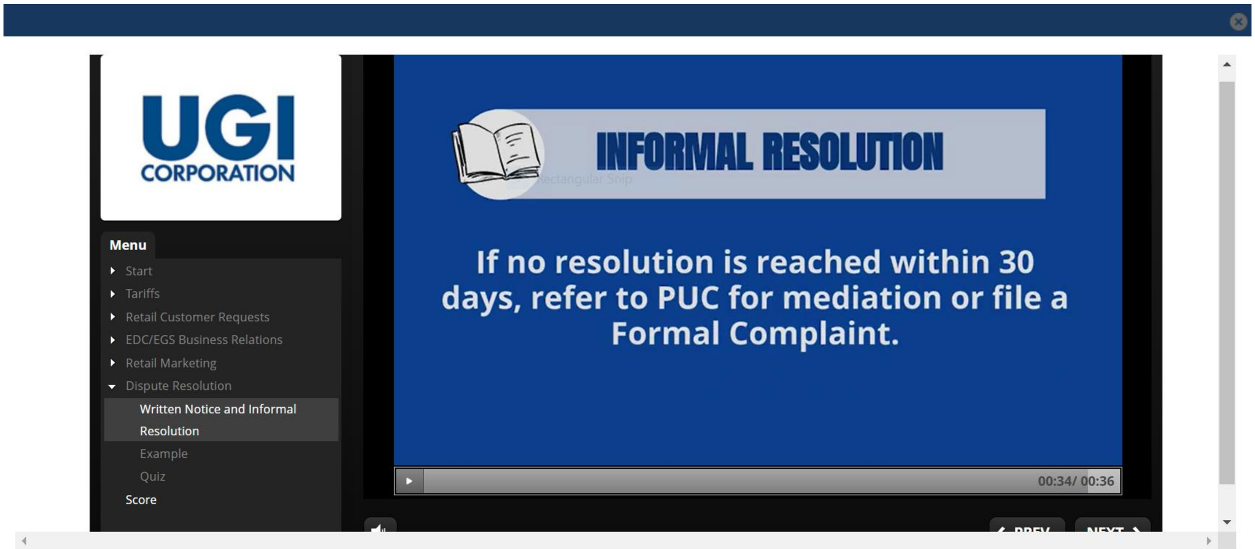

UGI
CORPORATION
Menu
EDC/EGS Business Relations
Retail Marketing
False or Deceptive Trade Practices
Example
Quiz
Affiliation Disclaimer
Example
Quiz
No False or Deceptive Advertising
Example
FALSE OR DECEPTIVE TRADE PRACTICES
Do not engage in false or deceptive trade practices regarding retail supply service.
00:09/ 00:13


UGI
CORPORATION
Menu
EDC/EGS Business Relations
Retail Marketing
False or Deceptive Trade Practices
Example
Quiz
Affiliation Disclaimer
Example
Quiz
No False or Deceptive Advertising
Example
AFFILIATION DISCLAIMER
Do market to the public with a disclaimer:
1) The affiliated EGS is not the same company as the EDC
2) The EGS' prices are not regulated by the PUC
3) That customers don't have to contract with the affiliate to receive quality service from the EDC
00:11/ 00:30


UGI
CORPORATION
Menu
EDC/EGS Business Relations
Retail Marketing
False or Deceptive Trade
Practices
Example
Quiz
Affiliation Disclaimer
Example
Quiz
No False or Deceptive
Advertising
Example
Quiz
NO FALSE OR DECEPTIVE
ADVERTISING
Include these disclaimers when
advertising through television and radio.
00:09/ 00:13
NEXT


UGI
CORPORATION
Menu
Start
Tariffs
Retail Customer Requests
EDC/EGS Business Relations
Retail Marketing
Dispute Resolution
Written Notice and Informal
Resolution
Example
Quiz
Score
WRITTEN NOTICE
Provide written notice of disputes,
including party or customer names and
a brief description of the matter.
00:11/ 00:36


UGI
CORPORATION
Menu
Start
Tariffs
Retail Customer Requests
EDC/EGS Business Relations
Retail Marketing
Dispute Resolution
Written Notice and Informal
Resolution
Example
Quiz
Score
INFORMAL RESOLUTION
Designate a senior representative to
informally attempt resolution within 5
days of receiving the dispute notice.
00:24/ 00:36
PREV
NEXT


UGI
CORPORATION
Menu
Start
Tariffs
Retail Customer Requests
EDC/EGS Business Relations
Retail Marketing
Dispute Resolution
Written Notice and Informal Resolution
Example
Quiz
Score
INFORMAL RESOLUTION
If no resolution is reached within 30 days, refer to PUC for mediation or file a Formal Complaint.
00:34/ 00:36

NRG Exhibit CR-4

NRG-I-9

Request:

Regarding an ongoing operational issue regarding the lack of timely notifications over the weekend of utility cuts, please indicate whether UGI has considered the use of automatic notifications so that an NGS has an opportunity to promptly correct the nomination. If so, please describe the results of that analysis. If not, please note whether UGI is willing to consider this option.

Response:

UGI is not aware of ongoing operational issues concerning a lack of notifications with regard to utility supply cuts during weekend periods. Thus, the Company has not considered implementing automated programming for these notifications. The Company would welcome additional communications which might help the Company understand the frequency and impact of the alleged concerns.

Prepared by or under the supervision of: Christopher R. Brown

NRG Exhibit CR-5

From: Shirk, Zachary J
To: Malsch, Kimberly; Reyes, Christopher
Cc: GasMgmtGasTraders; GasMGMTAdmin
Subject: EXT Supplier Collaborative Follow-up
Date: Friday, July 30, 2021 4:22:48 PM

Caution: This email originated from outside of the organisation. Do not click links or open attachments unless you recognise the sender and know the content is safe.

Good Afternoon Kim/Chris,

I wanted to follow up on the two questions you had asked during the supplier collaborative

1. *Can we get improvements to the capacity release screens such as the specific rate class for each release and possibly the XD/LFD customer names associated with releases?*
   Over the next few months, supply will be labelling the XD/LFD/DS releases so that on the EMW, they will show up under the comments section denoting which rate group the release is for. While the customer names associated with the releases is possible for XD, LFD and DS are released at a pool level and will have multiple customers that the release represents, so this is something we would only be able to do for XD.
2. *Can you please take back a request to see cuts real time in EMW?*
   With UGI's current programming, the process for identifying and communicating cuts is still a very manual effort for the supply team. While automating the process is a very long-term goal, it is not something we will be able to implement any time soon.

Please let me know if you have any other questions or concerns.

Thank you and have a good weekend!

Zachary Shirk
Sr Supervisor – Energy Supply Scheduling
1 UGI Drive
Denver, PA 17517
Office: 610-796-3492
Cell: 484-269-3079
ICE IM: zshirk

NRG Exhibit CR-6

NRG-I-10

Request:

As to the weighted average cost of delivered gas ("WACOD") used for recovery of charges for released capacity, the Company currently provides monthly information on its EBB showing the WACOD rates as reflecting pipeline rate changes. Please explain why this information does not show the total dollar impact of each specific rate case on the WACOD each month. In responding, please indicate whether the Company is willing to present the information in this manner on its EBB on a monthly basis.

Response:

The Company's WACOD calculation process utilizes only effective pipeline rates and does not support rate impact segmentation as described. The Company has not evaluated any functional requirement changes, related costs, timing or cost/benefit analysis which would be required to provide the functionality in support of the information of the type suggested.

Prepared by or under the supervision of: Christopher R. Brown

NRG Exhibit CR-7

UGI is notifying shippers serving LFD and DS customers on its system of the following adjustments starting with the April 2022 Weighted Average Cost of Demand (WACOD) rate.

Adjustment for Economic Benefit of Peaking Service (EBPS)

According to the Settlement of the 2019 UGI Rate Case at Docket R-2018-3006814, UGI provides an EBPS credit to LFD and DS Customers, up to the annual peaking premium impact to the WACOD related to peaking service contract cost allocations. Please reference the UGI Gas Division: Service Tariff No. 7 & Choice Supplier Tariff No. 7s Section 22.A.6 on the EMW for more information on the EBPS. UGI is issuing a $186,246.20 credit for LFD customers and a $925,256.22 credit for DS Customers, which reflects the annual peaking premium EPBS credit for the 2021-2022 winter peaking season. Based on UGI's tariff, this is the maximum economic benefit of peaking service that can be returned to these customers. UGI is also issuing an additional $2,358.24 credit for LFD customers and $5,836.04 credit for DS customers associated with the 2020-2021 winter peaking season related to a reconciliation for that period. The total EBPS credits issued are $188,604.44 for LFD customers and $931,092.26 for DS customers. Both credits will be applied to the April WACOD.

Adjustment for LFD Gross Up

UGI recently identified that LFD WACOD release rates have not been properly adjusted to reflect the portion of a customer's DFR allocated to delivered supply. The monthly WACOD rate was applied to capacity release quantities only (not the full LFD DFR quantity). This incorrectly excluded the Delivered Supply allocation of the shippers' monthly DFR volumes from having the WACOD charge applied. UGI has corrected the release cost calculation methodology for April releases to reflect the proper cost gross up on released quantities, thus having costs reflect the application of the full WACOD to the full DFR quantity. The under-collection impact of this error has been calculated by UGI and will be reconciled by adjusting the total costs in the LFD WACOD calculation by $46,120.10 per month over an equal twenty-nine month term during which this under-collection accumulated. This period will begin April 2022 and end August 2024.. Please note the projected WACOD rates found on the EMW include these adjustments, as well as a sample calculation for the LFD WACOD 'gross up' adjustment.

In summary, as a result of these adjustments, for the month of April the LFD WACOD rate will be $11.82, and the DS WACOD rate will be $6.86. The updated projected WACOD sheet is posted on UGI's EMW.

If you have any questions, please contact UGIGasCompliance@ugi.com.

Jamie Jowers

Sr Supervisor – Energy Supply and Regulatory Planning.

NRG Statement No. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pa. Public Utility Commission	:	
	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
	:	
UGI Utilities, Inc. – Gas Division	:	

SURREBUTTAL TESTIMONY OF

CHRISTOPHER REYES

ON BEHALF OF NRG ENERGY, INC.

TOPICS:

Standards of Conduct
Transparency of Delivery System
Operational Issues
Weighted Average Cost of Delivered Gas

May 27, 2022

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Christopher Reyes and I am Sr. Manager, Regional Operations (NY Metro, North East & Mid-Atlantic) for NRG Energy, Inc. ("NRG"). My business address is 194 Wood Avenue S., Iselin, New Jersey 08830.

Q. DID YOU SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. ON WHOSE BEHALF IS THIS SURREBUTTAL TESTIMONY OFFERED?

This Surrebuttal Testimony is offered on behalf of NRG. As natural gas suppliers ("NGSs") licensed by the Pennsylvania Public Utility Commission ("Commission"), NRG's subsidiaries supply natural gas services to retail consumers in the Company's service territory.[1]

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimony of Christopher R. Brown submitted by UGI Utilities, Inc. – Gas Division ("UGI" or "Company"). (UGI Statement No. 1-R). Specifically, my Surrebuttal Testimony addresses the following issues: (1) Commission's Standards of Conduct; (2) Transparency of UGI's Delivery System; (3) Operational Issues; and (4) Weighted Average Cost of Delivered Gas.

[1] As NGSs in Pennsylvania, NRG subsidiaries hold licenses as follows: Independence Energy Group d/b/a Cirro Energy: A-2013-2396449; Reliant Energy Northeast LLC d/b/a NRG Home, NRG Business, NRG Retail Solutions: A-2015-2478293; Green Mountain Energy Company: A-2017-2583732; XOOM Energy Pennsylvania, LLC: A-2012-2283967; Stream Energy Pennsylvania, LLC: A-2012-2308991; Direct Energy Services, LLC: A-125135; Direct Energy Business, LLC: A-125072; Direct Energy Business Marketing, LLC: A-2013-2365792; Gateway Energy Services Corporation: A-2009-2138725.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH THIS TESTIMONY?

A. Yes. I am sponsoring NRG Exhibit CR-8, which is attached to this testimony.

II. STANDARDS OF CONDUCT

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY CONCERNING THE COMMISSION'S STANDARDS OF CONDUCT.

A. The Commission has Standards of Conduct that are applicable to natural gas distribution companies ("NGDCs") and NGSs at 52 Pa. Code § 62.142, which contain several key provisions that address obligations of NGDCs when they have an affiliated NGS competing against nonaffiliated NGSs in the retail natural gas market. Among the topics covered by the Standards of Conduct are the sharing of employees, the allocation of costs, the maintaining of separate books and records and the application of tariff provisions. It is my understanding that the purpose of the Standards of Conduct is to ensure a level playing field for all market participants, which ultimately benefits consumers.[2]

Q. WHAT IS THE SIGNIFICANCE OF THE COMMISSION'S STANDARDS OF CONDUCT?

A. The significance of the Commission's Standards of Conduct is that UGI's affiliate, UGI Energy Services, LLC ("UGI-ES"), is operating in the retail market as a licensed NGS.[3] To my knowledge, no other natural gas or electric utility in Pennsylvania has an affiliate serving retail customers. As I explained in my Direct Testimony, UGI's vigilance in complying with these Standards of Conduct is critical to the robust functioning of the competitive retail market. (NRG Statement No. 1 at 4-9).

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[2] *Permanent Standards of Conduct Pursuant to 66 Pa.C.S. §2209(b)*, Docket No. L-00030162 (Proposed Rulemaking Order entered September 23, 2003, at 1).

[3] NRG Exhibit CR-1, attached to my Direct Testimony.

Q. WHAT DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY?

A. I offered a series of recommendations involving review by the Commission staff of UGI's practices as a way of ensuring full compliance with the Standards of Conduct. (NRG Statement No. 1 at 5-9).

Q. HOW DOES MR. BROWN ADDRESS YOUR TESTIMONY REGARDING THE STANDARDS OF CONDUCT?

A. Mr. Brown testifies that UGI is committed to compliance with the Standards of Conduct, which it shows through annual training, internal audits, regular meetings, and process reviews by senior management and Company executives. He further points to the lack of specific fact-based allegations in my Direct Testimony. Mr. Brown concludes that no action is required by the Commission. (UGI Statement No. 1-R at 16-21).

Q. PLEASE RESPOND.

A. As an initial matter, I note that NRG asked UGI in discovery to explain what measures it takes to ensure compliance with various specific provisions of the Standards of Conduct. In response, UGI provided a confidential Cost Allocation Manual and confidential training materials. The discovery response included no indication of the frequency of training and was devoid of any reference to the other measures that Mr. Brown has now identified in his Rebuttal Testimony.[4]

With respect to Mr. Brown's observation that my Direct Testimony does not contain specific fact-based allegations, that is due to my lack of access to information that is available only to UGI and the Commission. My concerns and recommendations are driven solely by the fact that UGI has an affiliated supplier competing in the retail market against NRG's subsidiaries, making compliance with the Standards of Conduct necessary

[4] Confidential NRG Exhibit CR-3, attached to my Direct Testimony.

to ensure that UGI-ES does not have a competitive edge over nonaffiliated NGSs. Given the existence of an affiliated NGS in the market, and the adverse effect on the market if any preferences are being shown, I believe it is imperative for the Commission to exercise its authority to ensure that UGI is strictly following the Standards of Conducts. Assuming UGI is fully compliant and taking adequate measures to maintain such compliance, UGI should have no concerns about regulatory scrutiny.

Q. PLEASE SUMMARIZE YOUR CONCERN ABOUT THE SHARING OF EMPLOYEES BETWEEN UGI AND UGI-ES.

A. As I explained in my Direct Testimony, I have personally observed employees migrating back and forth between UGI and UGI-ES, which shows that they are being shared by both entities. (NRG Statement No. 1 at 5).

Q. HOW DOES MR. BROWN RESPOND?

A. Mr. Brown notes that in response to discovery, I identified three management employees from UGI-ES who were previously UGI employees whom I have observed migrating back and forth. He testifies that these three individuals have extensive training and experience relating to the Standards of Conduct. (UGI Statement No. 1-R at 17-18).

Q. DOES THIS RESPONSE ADDRESS YOUR CONCERNS?

A. Not entirely. I continue to believe that some level of Commission oversight is warranted, as recommended in my Direct Testimony. (NRG Statement No. 1 at 5-6). At the very least, this situation raises a concern about the optics that the Commission should examine. Further, I note that NRG asked UGI in discovery to identify Company employees who are shared with UGI-ES, including name, title and brief description of responsibilities. Rather than responding to the question, Mr. Brown indicated that there are no shared employees with responsibilities that would violate the Standards of

Conduct.[5] This response did not give NRG an opportunity to consider whether we might have a different view than Mr. Brown does about whether certain employees have responsibility for operating the distribution system, marketing or customer service.

Q. PLEASE DESCRIBE MR. BROWN'S TESTIMONY RESPONDING TO YOUR RECOMMENDATION FOR A REVIEW OF CERTAIN STANDARDS OF CONDUCT DURING AUDITS BY THE BUREAU OF AUDITS.

A. Mr. Brown notes that UGI is subject to regular audits by the Bureau of Audits that, among other things, address affiliate relations and cost allocations and refers to a Focused Management and Operations Audit issued in October 2019. He testifies that the Bureau of Audits made five findings and recommendations in these areas to improve the Company's tracking of affiliate costs and timekeeping for services rendered to affiliates. (UGI Statement No. 1-R at 19).

Q. HOW DO YOU RESPOND?

A. In my Direct Testimony, I recommended that to the extent that the Commission is not already addressing cost allocations and separate books and records requirements through periodic audits, it should direct the Bureau of Audits to undertake this review. (NRG Statement No. 1 at 7). Having reviewed the Commission's Focused Management and Operations Audit, I continue to have concerns.[6] The Bureau of Audits described UGI's affiliated interest and cost allocation practices as needing "moderate improvement."[7] Further, Section V of the Audit Report, entitled Affiliated Interests and Cost Allocations, refers only to training that UGI provides to employees about functional separation and

[5] NRG Exhibit CR-8 (UGI Response to NRG-II-1).

[6] The Audit Report issued in October 2019 is available here.

[7] Audit Report, p. 4, Exhibit I-1.

the sharing of employees.[8] Of note, the Audit Report found that UGI could not "substantiate whether the costs of goods and services received from, or provided to, its affiliates are fair and reasonable."[9] The Audit Report also found that UGI's CAM lacks key information and should be updated.[10] Another finding observed that although UGI's CAM indicates that non-regulated affiliates should be charged for labor and overhead by direct charge, UGI has no documentation or formalized process providing guidance for employees to direct charge an affiliate for shared services.[11] This finding is similar to the concern I expressed in my Direct Testimony where I stated that if UGI is following its CAM, costs are likely being properly allocated. However, merely having the CAM in place does not provide any assurances if UGI is not following the directives set forth in the manual. (NRG Statement No. 1 at 6-7).

While UGI indicates that it has implemented the recommendations associated with these findings, it is not unreasonable for NGSs competing against UGI-ES to expect verification of those efforts and a determination that what UGI has done fully satisfies the Standards of Conduct. It is noteworthy that when the Commission delved into UGI's affiliate interest and cost allocation practices, the auditors identified shortcomings and made recommendations. These findings support the greater scrutiny I have recommended in connection with UGI's compliance with the Standards of Conduct.

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8 Audit Report, p. 26.

9 Audit Report, p. 27.

10 Audit Report, p. 28.

11 Audit Report, pp. 29-30.

III. TRANSPARENCY OF UGI'S DELIVERY SYSTEM

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY REGARDING THE TRANSPARENCY OF UGI'S DELIVERY SYSTEM.

A. Referring to the Sunberry Capacity as example, I noted that when available interstate pipeline capacity is being bid, there are instances when the capability to move gas between regional pools on UGI's delivery system was known only to UGI and UGI-ES. Had the information been public, there would have been a more robust interest in the open season by competitors of UGI-ES. (NRG Statement No. 1 at 10-11).

Q. WHAT DID YOU RECOMMEND?

A. The Commission should direct UGI to provide information to NGSs that outlines the full capabilities of its delivery system when it receives gas from the interstate pipelines. These capabilities include how UGI is able to move gas between regional pools so as to ensure that NGSs are granted the same access and have the same understanding that UGI-ES is afforded. (NRG Statement No. 1 at 11).

Q. PLEASE DESCRIBE MR. BROWN'S REBUTTAL TESTIMONY ON THIS ISSUE.

A. Mr. Brown testifies that Sunbury was a publicly noticed open season that was certificated by the Federal Energy Regulatory Commission and that the rules "relating to delivery on Sunbury were developed through a collaborative process that determined delivery requirements and acceptable substitutes based on the hydraulic and supply characteristics of each geographic segment of the UGI Gas system." (UGI Statement No. 1-R at 22). He further states that UGI readily offers the information NRG is seeking to suppliers on its system and identifies the availability of interconnections for suppliers on UGI's Energy Management Website, system flexibility that is offered in the form of ranges for delivery points, and regularly scheduled supplier collaboratives. (UGI Statement No. 1-R at 22-23).

Q. DOES MR. BROWN'S RESPONSE ADDRESS YOUR CONCERNS?

A. No. I do not dispute UGI's use of the open season for Sunbury. However, at that time, NRG and other nonaffiliated NGSs were not aware of UGI's capability to move gas received from the interstate pipelines to the UGI south pool via a spur on UGI central. The information described by Mr. Brown is available to NGSs. What is not available to NGSs is knowledge of the full capabilities of UGI's delivery system when it receives gas from the interstate pipelines. These capabilities include how UGI is able to move gas between regional pools.

IV. <u>OPERATIONAL ISSUES</u>

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY REGARDING OPERATIONAL ISSUES?

A. I described an issue that NRG is experiencing regarding the lack of timely notifications of utility cuts, which occur when a nomination made by an NGS needs to be corrected over the weekend. I recommended that UGI either implement automated programming for these notifications or implement weekend staffing.

Q. HOW DOES MR. BROWN ADDRESS THIS ISSUE?

A. Mr. Brown suggests that NRG's proposal for automated program may not be workable, and if workable, would likely have a very significant operational cost to UGI. He further testifies that he is not personally aware of any instances where UGI has cut supply over a weekend due to a mismatch between nominations provided by an NGS. Mr. Brown believes that the primary issue appears to be related to a lack of communication between NRG and its third-party suppliers. (UGI Statement No. 1-R at 23-24).

Q. PLEASE RESPOND.

A. Due to an interest in safeguarding their systems, it is standard industry practice for utilities to alert entities when a nomination is not confirmed. Every other utility with which I transact sends notifications seven days per week. Given the ability of the UGI to impose punitive penalties if an NGS does not meet the delivery requirement for the day, it stands to reason that the Company should provide these notifications seven days per week. In addition, I question the magnitude of any operational costs that would be incurred since someone at UGI is reviewing nominations over the weekend due to the need for the utility to balance on a daily basis.

Q. PLEASE DESCRIBE MR. BROWN'S TESTIMONY REGARDING NRG'S NOMINATION PRACTICES.

A. Mr. Brown notes that the deadline for Saturday, Sunday and Monday nominations is on Friday at 2:00 p.m. He then testifies that "[a] review of the Company's records indicates that NRG regularly fails to meet this deadline for its Sunday and Monday nominations." (UGI Statement No. 1-R at 25).

Q. PLEASE RESPOND.

A. The nomination deadline is unrelated to weekend notifications of cuts. It is nothing more than a red herring designed to be a distraction from the problem I have identified. That NRG regularly misses the deadline for its Sunday and Monday nominations is unavoidable due to mismatches between the utility deadline and the interstate pipelines' deadlines. As Mr. Brown is well aware, all NGSs are waiting to receive contracts from interstate pipelines by 2 p.m. on Friday, which makes a 2 p.m. utility deadline unrealistic for the Sunday and Monday nominations. Many third parties are involved in this robust process, and as an NGS, NRG is the end user waiting for it at the gate with no control over when the information is received so that the nomination can be submitted. Again, the issue I raised about weekend notifications has nothing to with the timeliness of NRG's nominations on Friday. Rather, the issue is that changes occur over the weekend of which NRG needs to be notified to avoid the risk of substantial penalties.

V. WEIGHTED AVERAGE COST OF DELIVERED GAS

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY REGARDING THE ISSUE WITH THE WEIGHTED AVERAGE COST OF DELIVERED GAS.

A. UGI uses weighted average cost of delivered ("WACOD") gas for recovery of charges for released capacity and provides monthly information on its Electronic Bulletin Board ("EBB") to show the WACOD gas rates as reflecting interstate pipeline rate changes approved by the Federal Energy Regulatory Commission. However, this information does not show the projected total dollar impact of each specific pipeline rate case on the WACOD gas rate each month. This is a problem because the individual impact of a rate case affects the natural gas prices that NRG is charging customers.

Q. WHAT DID YOU RECOMMEND?

A. I recommended that UGI provide NGSs with information showing the impact of each individual pipeline rate case along with a 12-month estimate of forward impact from the implementation of a rate change.

Q. HOW DOES MR. BROWN RESPOND?

A. Mr. Brown testifies that UGI identifies when FERC rate changes are first included in the WACOD and also identifies when any adjustments are made to reflect the final rates, as well as refunds. He explains that the Company does not separately itemize FERC rate impacts in the overall calculation or show an individual proceeding's particular impact on a monthly basis over time because this would be a resource intensive process. Mr.

Brown adds that NRG should be able to assess the impacts of various FERC proceedings on the cost of transportation service it relies upon in serving customers. (UGI Statement No. 1-R at 26).

Q. DOES MR. BROWN'S RESPONSE SATISFY YOUR CONCERN?

A. No. As I explained in my Direct Testimony, NRG is not asking UGI to undertake any additional work than it is already doing. Rather, NRG is requesting that UGI include the forecasts it has made to show the impact of the individual rate cases over a 12-month period following implementation.

Q. DID YOU IDENTIFY ANY OTHER CONCERNS ABOUT WACOD RATES?

A. Yes. In April 2022, UGI placed notices on its EBB regarding a credit for Economic Benefit of Peaking Service ("EBPS") and an increase to the LFD WACOD rates. I recommended that both the EBPS and the LFD gross up should be removed from the LFD WACOD rates, which are included on NFG's invoice. This approach would be similar to the way these adjustments are handled for the DS rate.

Q. DOES MR. BROWN AGREE WITH THIS RECOMMENDATION?

A. No. Mr. Brown describes the "WACOD as a mechanism that is intended to fully reflect the costs of providing the transportation program to the customers who utilize it" and concludes that the EBPS and LFD costs are appropriately incorporated into the WACOD. He further indicates that any modifications to change the bill format will cause the Company to incur additional programming costs. (UGI Statement No 1-R at 27).

Q. PLEASE RESPOND.

A. As explained in my Direct Testimony, when both costs and credits are handled in the WACOD rates, the amounts are artificially high or low and as the costs or credits roll off, the rates can change dramatically especially when the utility is only posting a 12-month rate schedule. NRG should not be in a position of explaining UGI errors to its supply customers or be required to decide how to allocate credits/costs resulting from UGI adjustments, particularly when some of the affected customers were not being served by NRG when the charges were initially included on bills.

Q. DOES THAT COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes; however, I reserve the right to supplement this testimony as may be appropriate.

Verification

I, Christopher Reyes, state that I am Sr. Manager, Regional Operations (NY Metro, North East & Mid-Atlantic) for NRG Energy, Inc. ("NRG") and providing the foregoing Direct Testimony of NRG. I hereby state that the facts contained in the foregoing Direct Testimony are true and correct to the best of my knowledge, information and belief. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

May 27, 2022

/Christopher Reyes/
Christopher Reyes
Sr. Manager, Regional Operations, NRG Energy, Inc.

NRG Exhibit CR-8

NRG-II-1

Request:

1. Please reference the Commission's Standards of Conduct at 52 Pa. Code § 62.142(a)(13), which prohibit the sharing of certain natural gas distribution employees with affiliated natural gas suppliers.

   A. Please identify Company employees who are shared with UGI Energy Services, LLC ("UGI-ES"), including name, title and brief description of responsibilities.

   B. Please identify employees who have transferred from the Company to positions at UGI-ES, including name, title, brief description of responsibilities, date of transfer and last date of employment. In describing responsibilities, please note whether the employee has responsibility for operating the distribution system, including natural gas delivery or billing and metering, or for marketing and customer service.

   C. Please identify employees who have transferred to the Company from positions at UGI-ES, including name, title, brief description of responsibilities, date of transfer and last date of employment. In describing responsibilities, please note whether the employee has responsibility for operating the distribution system, including natural gas delivery or billing and metering, or for marketing and customer service.

Response:

A. None. There are no shared employees "who have responsibility for operating the distribution system, including natural gas delivery or billing and metering, as well as those responsible for marketing and customer service."

B. Data for the last three years is provided in Attachment NRG-II-1(B).

C. Data for the last three years is provided in Attachment NRG-II-1(C).

Prepared by or under the supervision of: Christopher R. Brown

UGI Utilities, Inc. - Gas Division
List of Employee Transfers from UGI Utilities (UGIU) to UGI Energy Services (UGIES)

Employee Title	Department	Responsibilities	Last Date of Employment at UGI Utilities	Transfer Date to UGIES
Dispatcher I	Central Dispatch	Dispatch for field operations	4/28/2019	4/29/2019
Mgr Finance Cntrls/Prcs Imprvmnt	UNITE	Improve efficiency and accuracy of accounting processes	7/21/2019	7/22/2019
Customer Care Rep II	Customer Info Center	Call center representative	9/29/2019	9/30/2019
Controller & PAO	Accounting Services	Leads accounting department	11/10/2019	11/11/2019
Corrosion Control Tech III	Corrosion Control North	Prevent and mitigate corrosion of pipeline	11/10/2019	11/11/2019
Engineer II	Engineering Design	Work on design of delivery system	2/2/2020	2/3/2020
Sr Spvr Operations-C&M	Operations-Harrisburg	Leads operations office	2/2/2020	2/3/2020
Sr Mgr Major Accounts	Major Accounts	Leads major account marketing	2/16/2020	2/17/2020
VP Engineering & Oper Support	Engineering	Leads engineering and operations support	3/1/2020	3/2/2020
Dir Energy Supply & Planning	Energy Supply	Leads energy supply procurement team	10/11/2020	10/12/2020
Category Management Admin II	Sourcing	Company-wide procurement	2/14/2021	2/15/2021
Sr Spvr Energy Supply Scheduling	Energy Supply	Energy supply procurement	2/14/2021	2/15/2021
Customer Care Representative III	Cust Info Center	Call center representative	9/12/2021	9/13/2021

UGI Utilities, Inc. - Gas Division
List of Employee Transfers from UGI Energy Services (UGIES) to UGI Utilities (UGIU)

Employee Title	Department	Responsibilities	Last Date of Employment at UGIES	Transfer Date To UGI Utilities
Sr Dir Financial Planning & Analysis	FP&A	Lead budgeting and financial reporting	12/8/2019	12/9/2019
Director Capital Project Management	Engineering VP	Lead management of growth and R&B capital projects	1/5/2020	1/6/2020
Telemetry Technician	Telemetry	Maintain and repair telemetry equipment	3/15/2020	3/16/2020
Sr Construction Admin-Capital Projects	Operations-VP	Administrator in capital project group	8/30/2020	8/31/2020
Sr Spvr Capital Construction	Operations-VP	Supervisor capital construction projects	9/27/2020	9/28/2020
Director Procurement Natural Gas	Sourcing	Lead company-wide procurement department	9/27/2020	9/28/2020
Dir Energy Supply & Planning	Energy Supply	Lead Energy supply procurement	10/11/2020	10/12/2020
Principal Advisory System Leader	IT Solution Operations	Provides advisory services on technical infrastructure projects	11/8/2020	11/9/2020
Service Desk Specialist II	IT Solution Operations	Provide IT assistance to employees	11/22/2020	11/23/2020
Dir IT Systems Operations	IT Mgmt & Administration	Director of IT Systems Operations Group	1/17/2021	1/18/2021
Legislative Affairs Director	Regulatory Affairs	Legislative contact	1/17/2021	1/18/2021
Mgr Organization Change Management	UNITE	Lead change management under UNITE	1/17/2021	1/18/2021
Procurement Specialist I	Sourcing	Purchasing	2/14/2021	2/15/2021
Cyber Security Analyst II	Cybr Secur & Risk Mgt	Responsible for cybersecurity initiatives	3/28/2021	3/29/2021
Principal Project Manager-Acquisition	Rates	Project management for Mountaineer acquisition	4/11/2021	4/12/2021
Security Access Admin I	IT Goverance & PMO	Provide IT system access	5/2/2021	5/3/2021
Sr Analyst-Gas Supply Planning	Energy Supply	Energy supply procurement	8/15/2021	8/16/2021
Reporting Lead	UNITE	Develop company-wide reporting strategy under UNITE	8/15/2021	8/16/2021
Welder	Operations-Harrisburg	Field operations	11/7/2021	11/8/2021
Operations Lead II	Operations-Lancaster	Field operations	11/7/2021	11/8/2021

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. - Gas Division	:	

DIRECT TESTIMONY OF HARRY S. GELLER

ON BEHALF OF

THE COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA ("CAUSE-PA")

April 20, 2022

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PREPARED DIRECT TESTIMONY OF HARRY S. GELLER

Q: Please state your name, occupation, and business address.

A: My name is Harry S. Geller. I am an attorney. I am retired as the Executive Director of the Pennsylvania Utility Law Project (PULP), but have maintained an office at 118 Locust St., Harrisburg, PA 17101 for the purpose of providing consulting services and assistance to low income individuals and the organizations which represent them in utility and energy matters. Since the Governor's Emergency Order regarding the Covid-19 pandemic, I have been working from 4213 Orchard Hill Rd, Harrisburg, PA, 17110.

Q: Briefly outline your education and professional background.

A: I received my B.A. degree from Harpur College, State University of New York at Binghamton in 1966, and a J.D. degree from Washington College of Law, American University in 1969. Upon graduation from law school, I entered the Volunteers in Service to America (VISTA) program, where I was assigned to the New York University Law School. I took courses in the Law School's Urban Affairs and Poverty Law program and worked with the Community In Action Program on the West Side of Manhattan in New York City from 1969-1971. In 1971, I started as a Staff Attorney for the New York City Legal Aid Society, Criminal Court, and Supreme Court Branches in New York County. In 1974, I moved to Pennsylvania and began working for Legal Services, Incorporated (LSI). LSI was a civil legal aid program serving Adams, Cumberland, Franklin, and Fulton Counties. I worked at LSI from 1974-1987 first as a Staff Attorney, then as Managing Attorney, and ultimately became Executive Director. Through a restructuring with other legal services programs, LSI became part of what is now known as MidPenn Legal Services and Franklin County Legal Services.

In 1988, I was hired to be the Executive Director of PULP, a statewide legal aid project dedicated to protecting the rights of low income utility customers. At PULP, I represented low income individuals with utility and energy concerns and supported organizations advocating for low income households in utility and energy matters. As the Executive Director, I consulted and co-counseled on a wide variety of individual utility consumer cases, and I participated in task forces, work groups and advisory panels, including serving as chair of the Department of Human Services' LIHEAP Advisory Committee and the Pennsylvania Public Utility Commissions' Consumer Advisory Committee. I frequently trained communities, legal aid staff, and advocacy groups across Pennsylvania about the various utility and energy matters affecting Pennsylvania's low income population. I retired from PULP on June 30, 2015. Since that time, I have continued to provide consulting services for PULP and its clients, as well as other organizations serving the low income community.

In sum, I have over 50 years' experience working on behalf of households in poverty, including the past 30 years focusing specifically on utility and energy issues affecting low income consumers. My resume is attached as Appendix A.

Q: Please describe the focus of your work over the past fifty years, including relevant work experience on issues of low income families' ability to afford essential services such as utilities?

A: I have represented low income individuals and organizations serving low income populations in a wide variety of legal matters, including family law, public benefits, unemployment compensation, utility shut-offs, debtor/creditor, and housing-related disputes. Over the past 30 years, my focus has been to ensure that low income households can connect to, afford, and maintain utility and energy services.

In all of these legal matters, I worked almost exclusively on behalf of individuals and households that subsist on incomes at or below 150% of the Federal Poverty Level (FPL). Through this work, I have had a close view of the daily lives of countless of our poorest citizens. I have spent thousands of hours assisting clients, combing through their budgets to see whether it is even possible to make ends meet. Over the years, I have consistently seen the near total absence of the ability of low income families to afford the most basic monthly necessities with the incomes they have, even assuming heroic self-control and conscientious budgeting and spending. Almost every month, my clients faced the stark reality of having to choose which bills they can forgo with the least drastic consequences.

In addition to my deep understanding of the daily monetary struggles facing poor families, I have an extensive knowledge of the array of programs designed to allow low income individuals to afford utility service. While at PULP, I was involved in hundreds of proceedings evaluating the effectiveness of programs that are intended to reduce low income households' energy burdens and help them conserve energy through efficiency and weatherization. I have spent thousands of hours evaluating universal service programs and making recommendations for changes to these programs to better serve low income consumers. This advocacy ultimately led to the recognition of the need to develop integrated programs for low income consumers. Furthermore, I played an instrumental role in the development, oversight, and monitoring of the initial pilot and then the statutorily required low income universal service programs, each of which is structured to provide a different yet complimentary form of assistance to low income customers to enable those customers to afford and maintain basic service.

For example, the Customer Assistance Program (CAP) provides alternatives to traditional collection methods for low income, payment troubled utility customers, allowing participants to receive a more affordable bill and earn forgiveness on arrears in exchange for making in-full payments on their discounted bill. In turn, the Low Income Usage Reduction Program (LIURP) is a targeted weatherization program designed to assist low income households with the highest energy consumption, payment problems, and arrearages to reduce their overall energy consumption. CAP and LIURP work in tandem and are designed to assist low income households in maintaining affordable utility services and safe living environments while reducing utility collection, thereby benefitting other ratepayers and the communities in which they live and work.

Q: Have you testified in any proceeding before the Pennsylvania PUC?

A: Yes. I have presented testimony in many proceedings before the PUC. A complete list is included in my resume, which is attached as Appendix A.

Q: For whom are you testifying in this proceeding?

A: I am testifying on behalf of the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA).

Q: What is the purpose of your testimony?

A: CAUSE-PA intervened in this proceeding to ensure that the proposed rate increase and rate design will not adversely affect UGI's low income customers' ability to connect to, maintain, and afford natural gas service, which is essential for heating, cooking, and hot water – all critical components to a safe and healthy home.

Q: How is your testimony organized?

A: My testimony is divided into five sections.

In section I, I will discuss the financial impact that UGI's proposed residential rate increase will have on its low income customers. UGI's proposed rate increase would raise residential customer bills by 9.5%.[1] According to UGI's estimates, approximately 25% of its residential customers have income at or below 150% of the Federal Poverty Level (FPL).[2] These households struggle to afford life's most basic necessities and increasing the cost of natural gas service will worsen these struggles, leading to increased payment troubles and, in turn, increased termination rates and resulting uncollectible expenses. As I will explain, UGI's current universal service programs do not adequately address the affordability gap for economically vulnerable customers. If approved, this rate increase will make it more difficult for low income consumers to maintain safe energy services to their home. UGI must do more to improve access and affordability of its universal service programs.

In section II, I will review UGI's existing universal service programs, and will discuss the impact of UGI's rate increase on universal service program participants. I make several recommendations for how UGI can mitigate the impact of the rate increase on UGI's economically vulnerable consumers by making targeted improvements to its universal service programs.

In section III, I discuss UGI's proposed rate design, which seeks to recover an increased portion of the residential cost of service through a fixed monthly customer charge and will address UGI's proposed Weather Normalization Adjustment (WNA). Increases to the fixed customer charge impede customers' ability to reduce their energy costs through energy efficiency measures; thus, if the Commission decides to allow any rate increase, it should be added exclusively to the volumetric charge. Also, UGI's proposed WNA shifts the risk of changing weather patterns from

[1] UGI St. 1 at 7.
[2] See OCA to UGI II-17, 18, 19 (As of December 2021, UGI reported having 610,158 residential customers, 153,437 estimated low income customers, and 78,450 confirmed low income customers.).

the utility to the consumer and prevents low income customers from realizing bill savings due to warming trends. For these reasons, as explained more thoroughly below, I recommend that the Commission reject UGI's fixed charge and WNA proposals.

In section IV, I discuss UGI's late fees and reconnection fees. As I explain, UGI's late fees and reconnection fees unfairly penalize low income customers that are unable to afford their bill. Late fees and reconnection fees do not motivate payment from economically vulnerable households – they compound financial instability and raise additional barriers to households seeking to prevent termination and/or reconnect service. Thus, I recommend that UGI no longer assess late fees and reconnection fees to confirmed low income customers.

Finally, in section V, I summarize the recommendations and proposals provided throughout my direct testimony.

I. IMPACT OF UGI'S RATE PROPOSAL ON LOW INCOME HOUSEHOLDS

Q: Please summarize UGI's requested rate increase as it applies to residential customers.

A: UGI proposes to increase its distribution rates by approximately $82.7 million per year, or 7.8% on a total revenue basis.[3] The rate increase to individual customers will depend on each customer's level of usage. However, most of the impact of UGI's proposed rate increase for residential customers comes from a substantial increase to the fixed monthly service charge – from $14.60 to $19.95, an increase of $5.35 or 36.6%.[4] Thus, homes using the least amount of gas will face the highest percentage increase, while homes using more gas will see a lower percentage

[3] UGI St. 1 at 6.
[4] UGI St. 8 at 20.

increase. The total bill for the average residential heating customer purchasing gas from UGI would increase from $98.62 to $108.01 per month, or 9.5%.[5]

Q: How many low income consumers reside in UGI's service territory?

A: Like other large regulated public utilities in Pennsylvania, UGI tracks its low-income customer population two ways. First, an "estimated low-income customer" count, which uses census data and UGI's residential customer count to estimate the likely number of customers in UGI's service territory with low income.[6] Second, a "confirmed low-income customer" count, which includes only those customers from whom UGI has obtained information documenting low income or who UGI has identified as receiving LIHEAP.[7] As of December 2021, UGI reported having an estimated low income customer count of 153,437 (approximately 25% of residential customers) and a confirmed low income customer count of 78,450 (approximately 13% of residential customers).[8]

While both metrics show that a substantial number of UGI's customers are low-income, the estimated low-income customer figure (25%) presents a more accurate picture of the low income population in UGI's service territory. The confirmed low-income customer count provides only a limited subset and skewed assessment of the low-income population – counting only the number of customers who have affirmatively sought out and obtained assistance in the last year. The estimated low-income customer count provides a more realistic assessment of the number of low-income households served by UGI by using verified census data proportional to its service

[5] UGI St. 1 at 7.
[6] CAUSE-PA to UGI IV-2.
[7] Id. at IV-1.
[8] See OCA to UGI II-17, 18, 19 (As of Dec. 2021, UGI reported 610,158 residential, 153,437 estimated low income, and 78,450 confirmed low income customers.).

territory and customer data. Regardless of the measure applied, there are a substantial number of low-income customers (between 13% to 25%) in UGI's service territory.

Q: What level of income qualifies a household as a "low income"?

A: With some exceptions, most utility assistance programs require households to have income that is not greater than 150% of the federal poverty level (FPL) to qualify. The FPL is a measure of poverty based exclusively on the size of the household, but not the composition of the household (i.e., whether the household consists of adults or children) or geography. As a baseline, a family of four at 150% FPL has a gross annual income of just $41,265.[9] This is insufficient income to support a family of this size and is substantially less than a household this size needs to meet their basic expenses in any of the counties in UGI's service territory.[10]

The Self Sufficiency Standard is a benchmark often used to assess how much income a household needs to live without assistance in Pennsylvania. This tool measures the income that a family must earn to meet their basic needs and consists of the combined cost of 6 basic needs – housing, child care, food, health care, transportation, and taxes – without the help of public subsidies.[11] Unlike the federal poverty level, which does not change based on geographic location or family composition, the Self Sufficiency Standard accounts for the varied costs of these six basic needs in different geographical areas and for differently aged household members.[12] In 2021, the average Self Sufficiency Standard for a family of four in the Pennsylvania counties served by

[9] U.S. Dept. of Health and Human Services, 2022 U.S. Federal Poverty Guidelines, available at https://aspe.hhs.gov/topics/poverty-economic-mobility/poverty-guidelines
[10] Self Sufficiency Standard, http://www.selfsufficiencystandard.org/Pennsylvania.
[11] See PathWays PA, Overlooked and Undercounted 2019 Brief: Struggling to Make Ends Meet in Pennsylvania, available at: https://pathwayspa.org/wp-content/uploads/2020/01/PA2019_OverlookedUndercounted_Web.pdf
[12] See PathWays PA, Overlooked and Undercounted, How the Great Recession Impacted Household Self-Sufficiency in Pennsylvania, available at: http://www.selfsufficiencystandard.org/sites/default/files/selfsuff/docs/PA2012.pdf.

UGI was $62,617 – which is over $20,000 more than a household with income at 150% FPL makes in a given year.[13] Most of UGI's confirmed low income customers do not have income that is even close to these numbers. The average annual income for UGI's confirmed low income customers is just $12,084.[14] The average income for low income customers actively enrolled in UGI's Customer Assistance Program (CAP) is just $14,526.[15] Falling nearly $50,000 short of the average self-sufficiency standard in UGI's territory, these customers' household incomes are less than a quarter of the approximately $62,617 needed to be self-sufficient and live without financial assistance in UGI's service territory. Any increase in the cost of necessities, including the rates for natural gas for heating, cooking, and hot water, will result in increased unaffordability for low and moderate income households, and will likely result in a corresponding increased rate of involuntary service terminations and uncollectible expenses.

Q: How would UGI's proposed rate increase impact low-income households?

A: Low-income families struggle to make ends meet each month and are often forced to choose between critical necessities; thus, any increase in costs for essential services, like natural gas, will severely impact these households forcing many to make impossible trade-offs between paying for shelter, food, utilities, or other basic needs. UGI's proposed *average* monthly increase from $98.62 to $108.01 per month, an increase of $9.39 per month ($112.68 per year) is a substantial increase in basic living expenses even for many moderate income households. For low-

[13] Average Self Sufficiency Standard of all counties served by UGI for all four-person household types. See Sufficiency Standard – 2021 Pennsylvania Dataset, available at: http://www.selfsufficiencystandard.org/Pennsylvania;.

[14] CAUSE-PA to UGI I-15. Note that the average annual income for UGI's confirmed low income customers has dropped from $18,533 2020 to 12,084 in 2022; see Pa. PUC v. UGI Gas of Pennsylvania, Inc., Docket No. R-2019-3015162, CAUSE-PA St. 1, Direct Testimony of Mitchell Miller, at 13 (Submitted May 22, 2020).

[15] CAUSE-PA to UGI I- 16.

income households who already struggle to afford their monthly bills, the effects of the increase will impact their ability to connect to, maintain, and afford natural gas service.

To further contextualize the impact of the proposed increase on low-income households, it is helpful to look at the relative energy burden (the percentage of income a household pays for energy costs) of low-income households. For natural gas customers, the energy burden has two components, their electric bill burden and their natural gas bill burden. To be affordable, a household's total housing costs – *including utility costs* – should account for no more than 30% of the household's total income.[16] But across Pennsylvania, households with income at or below 150% FPL pay 9% or more of their income on *energy costs alone*, with households at or below 50% FPL paying 30% of their annual income simply for their home energy bills.[17] In comparison, the Commission's Bureau of Consumer Services (BCS) estimates that the combined energy burden of Pennsylvania's residential customers as a whole is roughly 4% of their household income (not including CAP customers).[18]

The average annual income for UGI's confirmed low income customers is $12,084, or $1,007 per month.[19] UGI's proposed rate increase would increase the total bill for the average residential heating customer from $98.62 to $108.01 per month.[20] If approved, the average energy burden for UGI's confirmed low income customers would increase from 9.8% to 10.7%, *not*

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[16] US Dep't of Housing & Urban Development, Affordable Housing, available at: https://www.hud.gov/program_offices/comm_planning/affordablehousing.

[17] See Fisher, Sheehan & Colton, The Home Energy Affordability Gap: Pennsylvania 2021 HEAG Fact Sheet (April 2022), available at: http://www.homeenergyaffordabilitygap.com/03a_affordabilityData.html.

[18] Energy Affordability for Low-income Customers, Docket No. M-201702587711, Order, at 8 (Jan. 17, 2019); see also Diana Hernandez, Energy Insecurity: A Framework for Understanding Energy, the Built Environment, and Health Among Vulnerable Populations in the Context of Climate Change, 103(4) Am. J. Pub. Health (2013), available at: http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3673265/#bib20.

[19] CAUSE-PA I-15.

[20] UGI St. 1 at 7.

including their electric bill burden. The energy burden for these customers is already far above what is considered affordable, and UGI proposes to raise it even higher.

Even with bill assistance through CAP, many of UGI's low-income consumers still face disproportionately high energy burdens.[21] In 2021, the natural gas bill burden for UGI CAP participants ranged between a low of 4.88% to a high of 15.15%.[22] It is worth noting that these excessive bill burdens were for natural gas service only – *not including the additional cost of their electric bill burden*. Notably, CAP only reaches a small portion of the eligible population. As of December 2021, only 22,025 of UGI's low income customers were enrolled in CAP,[23] which was only 28% of UGI's confirmed low-income customers[24] and 14% of its estimated low-income customers.[25] In other words, between 72-86% of UGI's low-income customers will bear the full impact of the proposed rate increase – without assistance from CAP.

The overwhelming energy burden on low-income households makes it difficult to pay for other basic necessities; has substantial and long-term impacts on mental and physical health; creates serious risks to the household and the larger community; and negatively impacts the greater economy.[26] According to the U.S. Energy Information Administration, in 2020, approximately one third of households surveyed reported household energy insecurity and nearly a quarter of households reported that they reduce or forego other critical necessities like food and medicine to afford their home energy costs.[27] In a 2018 survey conducted by the National Energy Assistance

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[21] CAUSE-PA to UGI I-12, Attachment.
[22] Id.
[23] OCA to UGI II-15, Attachment.
[24] Id. at II-17 (78,450 confirmed low income as of Dec. 2021).
[25] Id. (153,437 estimated low income customers as of Dec. 2021).
[26] US EIA, Residential Energy Consumption Survey 2020, available at: https://www.eia.gov/consumption/residential/data/2020/index.php?view=characteristics (hereinafter RECS Survey); see also NEADA, 2018 National Energy Assistance Survey, at 17, 20 (Dec. 2018), available at: http://neada.org/wp-content/uploads/2015/03/liheapsurvey2018.pdf (hereinafter NEADA Survey).
[27] RECS Survey, Table HC11.1 Household energy insecurity, 2020.

Directors' Association, 72% of LIHEAP recipients reported foregoing other necessities to afford energy, and 26% reported keeping their home at unsafe or unhealthy temperatures.[28]

Ultimately, an increase in rates for natural gas service such as the increase proposed here will necessarily result in increased unaffordability for vulnerable households and is likely to result in a corresponding increase in involuntary payment-related terminations and, in turn, uncollectible expenses borne by all residential ratepayers. These impacts can and do have a deep and lasting impact on the health and wellbeing of those in the household and the welfare of the entire community.[29]

Q: Is there other evidence that UGI's low-income customers already struggle to afford and maintain natural gas service – even before any rate increase is approved?

A: Yes. There are strong indicators that service is already unaffordable. UGI's low-income customers are disproportionately payment troubled and carry a disproportionate amount of residential consumer debt to the Company. These indicators demonstrate that UGI's low-income consumers already struggle to pay for natural gas service and will likely experience increased payment trouble if UGI's proposed rate increase is approved.

According to the 2020 Universal Service Report, 97.2% of UGI's payment troubled customers are confirmed low income customers, which is substantially higher than the industry average 72.6% and is the highest among all reporting natural gas distribution companies

[28] NEADA Survey at 17, 20.
[29] See id. When a family is unable to use their primary heating system, they often resort to dangerous, high usage, and high-cost alternative heating methods such as electric space-heaters, electric stoves, and/or portable generators, which increases the risk of carbon monoxide poisoning and house fires – placing themselves and the greater community at risk of harm. See Nat'l Fire Protection Ass'n, Fire Analysis & Research Division, Home Fires Involving Heating Equipment, at 1 (Dec. 2018) (finding that space heaters cause 44% of all home heating related fires, and 86% of deaths caused by home heating related fires).

(NGDCs).[30] The fact that nearly all of UGI's payment troubled customers are confirmed low income customers is particularly troubling because only approximately 13% of UGI's residential customers are confirmed low-income,[31] which is well below the industry average and the second lowest among NGDCs.[32] The number of low income customers experiencing payment trouble will likely worsen if UGI's proposed rate increase is approved without adopting targeted measures to mitigate the impact of the increase on low-income households.

UGI's confirmed low-income customers are not only disproportionately payment troubled, but they also carry a disproportionate percentage of customer debt compared to residential customers as a group. As of March 2022, approximately 30% of confirmed low-income customers were in debt to UGI, compared to just 11% of general residential customers.[33] Further, even though confirmed low-income customers only represent approximately 13% of UGI's residential ratepayers, they represent 38% of customers in debt[34] and carry a large majority (66%) of total dollars owed.[35]

Q: Did UGI make any changes to its policies and procedures impacting low income customers in response to the COVID-19 pandemic?

A: Yes. On March 13, 2020, the Commission issued an Emergency Order placing a moratorium on utility terminations due to the emergence of the COVID-19 pandemic.[36] Beginning March 18, 2020, UGI ceased removing customers from CAP for failure to recertify their income

[30] 2020 Universal Service Report at 11.
[31] See OCA to UGI II-17, 18, 19 (As of Dec. 2021, UGI reported 610,158 residential, 153,437 estimated low income, and 78,450 confirmed low income customers.).
[32] 2020 Universal Service Report at 6.
[33] CAUSE-PA to UGI IV-14, Attach.
[34] Id. (As of March 2022, 26,100 confirmed low income customers in debt out of 68,439 total residential customers in debt).
[35] Id. (As of March 2022, $26,301,342 of total residential debt belonged to confirmed low income customers out of $39,686,285 total residential dollars in debt).
[36] Pa. PUC Emergency COVID-19 Moratorium Order, Docket M-2020-3019244.

and instructed Community Based Organizations (CBOs) to accept telephonic "signatures" for CAP program authorizations.[37] On March 24, 2020, the Company began waiving all late payment charges.[38] UGI also implemented a Phase I Emergency Relief Program (ERP) to assist natural gas customers impacted by the Pandemic that provided grants of up to $400 for residential customers and ran from October through December 2020.[39] UGI's proposal for Phase II ERP was denied by the Commission, and the Company subsequently resumed normal low-income activities in July 2021.[40]

Q: How have low income customers been impacted by the expiration of the emergency COVID-19 measures?

A: While the emergency measures taken by the Commission and UGI undoubtedly helped UGI's customers maintain service despite the public health emergency and initial economic fallout of the COVID-19 pandemic, the expiration of these measures has disproportionately impacted UGI's low income customers, resulting in increased low income termination rates, debt, and CAP removals. After the discontinuance of the emergency COVID-19 measures, UGI's confirmed low income termination rate, CAP termination rate, and number of CAP removals have significantly increased compared to pre-COVID levels. As of June 2021, UGI resumed removing customers from CAP for failure to recertify.[41] From June 2021 through January 2022, 4,361 customers were removed from CAP for failure to recertify.[42] These 4,361 customers represent 18% of CAP customers that were enrolled as of June 2021.[43] For reference, only 380 customers were removed

[37] UGI St. 1 at 12.
[38] Id.
[39] UGI St. 1 at 15-16.
[40] Id.
[41] OCA to UGI II-44.
[42] Id. at II-16, Attach.
[43] Id. at II-15, Attach.

for failure to recertify in all of 2019.[44] Ultimately, many of these customers did not reenroll, as UGI's total CAP enrollment reduced from 24,164 in June 2021 to 20,245 in February 2022, a total decline of over 16%.[45]

The significant number of low income customers being removed from CAP as a result of recertification requirements has likely contributed to increased low income termination rates – which indicates that the decline in CAP enrollment is not due to a decline in the need for assistance. In 2021, UGI's confirmed low income termination rate was more than double its 2019 rate and its CAP termination rate was more than triple 2019 levels.[46] Meanwhile, its general residential termination rate remained similar to 2019 levels.[47] Table 1 and Table 2 show the changes to UGI's termination rates between 2019 and 2021.

TABLE 1 – 2019 UGI Termination Rates

2019	Residential Customers	Confirmed Low Income Customers	CAP Customers
Terminations	20,813[48]	1,385[49]	690[50]
Customer Count	593,709[51]	74,493[52]	23,451[53]
Termination Rate	3.5%	1.9%	2.9%

[44] OCA to UGI II-16, Attach.
[45] OCA to UGI II-15, Attach.
[46] See OCA to UGI II-15, II-16.
[47] Id.
[48] CAUSE-PA to UGI I-7.
[49] CAUSE-PA to UGI I-8.
[50] CAUSE-PA to UGI I-9.
[51] CAUSE-PA to UGI I-17.
[52] CAUSE-PA to UGI I-3.
[53] CAUSE-PA to UGI I-4.

TABLE 2 – 2021 UGI Termination Rates

2021	Residential Customers	Confirmed Low Income Customers	CAP Customers
Terminations	23,013[54]	3,848[55]	2,153[56]
Customer Count	610,158[57]	78,450[58]	22,025[59]
Termination Rate	3.8%	4.9%	9.8%

These tables show that there is a substantially higher rate of involuntary termination for low income households since the emergency pandemic measures expired. Notably, while the termination rate for residential customers remained largely consistent from 2019 to 2021, the termination rate for confirmed low income customers more than doubled and the termination rate for CAP customers more than tripled.

UGI reports that a substantial number of low income households are at risk of termination following expiration of the 2021-2022 winter termination moratorium. As of April 1, 2022, 5,840 confirmed low income customers (approximately 7%) and 4,680 CAP customers (approximately 23%) were at risk of termination; whereas approximately 5% of residential customers as a whole were at risk of termination. [60]

I note here that the explicit statutory purpose of CAP is to assist low income customers to maintain gas service to their home.[61] Yet last year, one in every ten CAP participants had their service involuntarily terminated because they could not afford to pay. The disparity in involuntary

[54] CAUSE-PA to UGI I-7.
[55] Id. at I-8.
[56] Id. at I-9.
[57] Id. at I-17.
[58] Id. at UGI I-3.
[59] Id. at I-4.
[60] See CAUSE-PA to UGI IV-8; see also OCA to UGI II-17 (confirmed low income count as of Jan. 2022); OCA to UGI II-15 (CAP customer count as of Feb. 2022), Attach; CAUSE-PA to UGI I-17 (residential customer count as of Jan. 2022).
[61] See 66 Pa. C.S. § 2202 (definition of "Universal Service and Energy Conservation").

termination rates concentrated across UGI's low income customer base underscores the need for UGI to remediate rate unaffordability by further strengthening the availability and assistance provided to low income consumers through its universal service programs to offset unaffordability at both existing and proposed rates.

Q: How does the involuntary termination of natural gas service impact a household?

A: Loss of natural gas service has a deep and lasting impact on the health and wellbeing of the entire household and the community as a whole and is a common catalyst to homelessness.[62] When a family is unable to use a primary heating system, they often resort to dangerous, high usage / high cost heating methods – such as electric space-heaters, electric stoves, and/or portable generators – which increases the risk of carbon monoxide poisoning and house fires.[63] Heating equipment is a leading cause of fires in U.S. homes.[64] Space heaters are most often responsible for home heating equipment fires, accounting for more than two in five fires, as well as the vast majority of the deaths and injuries in home fires caused by heating equipment.[65]As of February 2022, UGI reported that 344 of its residential customers were *known* to be without a central heating source in the winter months, and 25 households were *known* to be using a potentially unsafe alternative heating source.[66]

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[62] See Joint State Government Commission, General Assembly of the Commonwealth of Pennsylvania, Homelessness in Pennsylvania: Causes, Impacts, and Solutions: A Task Force and Advisory Committee Report (2016), available at: http://jsg.legis.state.pa.us/resources/documents/ftp/documents/HR550%201%20page%20summary%204-6-2016.pdf.

[63] Richard Campbell, Home Heating Fires, National Fire Protection Association (NFPA), (Jan. 2021), available at: https://www.nfpa.org/News-and-Research/Data-research-and-tools/US-Fire-Problem/Heating-equipment

[64] Id.

[65] Id.

[66] Pa. PUC, 2021 Cold Weather Survey Results – Gas, available at: https://www.puc.pa.gov/filing-resources/reports/electric-gas-water-cold-weather-survey-results/ .

UGI must take steps to protect its customers from the harsh consequences of its proposed rate increase. I will make several recommendations later in my testimony that will enable UGI to better protect these vulnerable customers.

II. UGI UNIVERSAL SERVICE PROGRAMS

Q: Please briefly describe UGI's Universal Service Programs.

A: As required by Commission regulations, UGI has established a Universal Service and Energy Conservation Plan (USECP).[67] UGI's universal service programs include (1) a Customer Assistance Program (CAP), (2) a Hardship Fund (Operation Share), (3) a Low Income Usage Reduction Program (LIURP), and (4) a Customer Assistance and Referral Evaluation Services (CARES).[68] In this section, I will address UGI's CAP, LIURP, and Operation Share programs and provide recommendations for how UGI should improve each of these programs to better address the need for assistance for UGI's low income customers to remediate rate unaffordability at both existing and proposed rates.

a. Customer Assistance Program (CAP)

Q: Are customers who are enrolled in the UGI's Customer Assistance Program (CAP) insulated from the financial impact of the rate increase?

A: The answer to this question differs from customer to customer and depends on the type of CAP payment plan a customer is assigned. UGI currently has three types of CAP rates: (1) a percentage of income (PIP) rate, which is calculated based on a fixed percentage of the customer's

[67] UGI 2020-2025 Universal Service and Energy Conservation Plan (USECP), Docket No M-2017-2598190 (2020-2025 USECP).
[68] Id. at 2.

income[69]; (2) an average bill rate, which is based on the customer's average 12-month bill; and (3) a minimum bill, which is set at $25 for heating CAP customers and $15 for non-heating CAP customers.[70] Once a customer enrolls in CAP, and a CAP rate is assigned, UGI adjusts the customer's rate on a quarterly basis to reflect the most recently applicable rates, usage, and income data available.[71]

About half (49%) of UGI's CAP customers receive a PIP or minimum bill CAP rate.[72] These CAP participants will be largely insulated from the financial impact of the proposed rate increase, assuming they can meet the recertification requirements and other obligations necessary to remain in the program.[73] That said, if rates are increased as proposed, the subsidy necessary to assist CAP participants with a PIP or minimum bill CAP rate will increase, which will consequently increase the cost of CAP to other residential ratepayers – including for those whose income is over 150% FPL but are nevertheless well below the self-sufficiency standard (discussed above).

The remaining 51% of CAP customers have CAP rates set according to their average bill rate. These CAP participants are not insulated from the impact of UGI's proposed rate increase and will experience the full financial impact of UGI's proposed rate increase.[74] UGI's quarterly CAP rate adjustments will shift some customers who are currently billed at the average bill rate

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[69] 2020-2025 USECP at 16 (Currently, UGI CAP customers with income between 0-50% FPL are billed at 7% of the household's monthly income; those with income between 51-100% FPL are billed at 8% of the household's monthly income; and those with income between 101-150% FPL are billed at 9% of the household's monthly income.).

[70] 2020-2025 USECP at 16-17.

[71] <u>See</u> UGI 2019 Rate Case, Docket No. R-2018-3006814, Joint Petition for Settlement at ¶ 47:

> On a quarterly basis, UGI Gas will review CAP rates for those enrolled in the average bill or percentage of income CAP rate plans to determine whether a more affordable rate plan is available. To the extent the CAP customer qualifies, the CAP customer's applicable CAP rate will be adjusted to the lowest available rate at the time of review.

[72] CAUSE-PA to UGI I-1.

[73] <u>Id.</u>

[74] <u>Id.</u>

into the percentage of income payment (PIP) category – which will help to limit (*but not eliminate*) the overall impact of the rate increase. However, customers transitioned from the average bill rate to the percentage of income bill rate as a result of the rate increase will still pay more because, prior to the rate increase, the average bill payment would have been less expensive than their applicable percentage of income will be after the rate increase. Of course, CAP customers who *remain* in the average bill rate category will experience the full, unmitigated impact of the rate increase.

Q: Are all low-income customers enrolled in CAP?

A: No. Less than a third of UGI's confirmed low-income customers are enrolled in CAP. As of December 2021, only 22,025 customers were enrolled in CAP,[75] which was only 28% of UGI's confirmed low-income customers[76] and 14% of its estimated low-income customers.[77] Thus, between 72-86% of UGI's low-income customers are left to bear the full impact of the proposed rate increase.

As I explained above, UGI's CAP enrollment and participation rate dropped significantly when the Company reinstated CAP recertification requirements after the expiration of the Commission's COVID-19 Emergency Order. However, even before the COVID-19 pandemic, UGI had a consistently lower CAP participation rate compared to the industry average.[78] Table 3 shows the CAP enrollment rate for UGI North and UGI South compared with the NGDC average over a 10-year period.[79]

[75] OCA to UGI II-15, Attachment.
[76] Id. at II-17 (78,450 confirmed low income as of Dec. 2021).
[77] Id. (153,437 estimated low income customers as of Dec. 2021).
[78] OCA to UGI II-16.
[79] *Note*: On Oct. 4, 2019, at Docket No. R-2018-3006814, et al., the Commission approved the merger of the UGI Utilities, Inc. separate rate districts – UGI South, UGI North, and UGI Central – into one rate district existing as

TABLE 3: CAP Participation Rate[80]

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
UGI North	19%	22%	18%	14%	14%	22%	25%	25%	24%	26%	29%
UGI South	24%	21%	17%	13%	11%	18%	21%	23%	24%	25%	31%
NGDC Avg.	40%	41%	40%	37%	36%	37%	35%	34%	34%	45%	34%

In 2020, UGI's CAP participation rate was 31% and the NGDC industry average CAP participation rate was 36.1%.[81] In 2021, UGI's CAP participation rate dropped to 28%.[82]

UGI's CAP participation rates are low compared to average CAP participation rates amongst other NGDCs in the Commonwealth and highlight the need for critical improvements to CAP outreach and enrollment processes to reach a greater number of households in need of assistance to access and maintain safe and affordable natural gas services to their homes. This is especially true if UGI's proposed rate increase is approved, as even more households will need assistance to keep up with increasing rates.

Q: Has UGI taken any steps that you believe will help improve its CAP participation rate?

UGI Utilities, Inc. – Gas Division. Although this change took effect when UGI's amended tariff became effective on Oct. 11, 2019, data reported based on the combined rate districts did not begin until Jan. 1, 2020. Prior to the merger, UGI Central was not subject to Universal Service Reporting requirements. See 2020 Universal Service Report at 1, fn. 9.

[80] The CAP enrollment rate is the total of CAP customers as of December 31 of the given year, divided by the number of confirmed low-income customers. CAP enrollment rates were collected from the Commission's Universal Service Programs & Collections Performance Reports (hereinafter Universal Service Reports). The last publicly available CAP enrollment data was released in December 2019 for the 2018 calendar year. See 2020 Universal Service Report at 58; 2018 Universal Service Report at 52; 2017 Universal Service Report at 51; 2016 Universal Service Report at 50; 2015 Universal Service Report at 42; 2014 Universal Service Report at 42; 2013 Universal Service Report at 37; 2011 Universal Service Report at 40; 2009 Universal Service Report at 39. Note that percentages were rounded to the nearest whole number.

[81] 2020 Universal Service Report at 58.

[82] See OCA to UGI II-15,17 (22,025 CAP customers and 78,450 CLI customers as of Dec. 2021).

A: Yes. I believe that adopting the Commission's recommended maximum CAP energy burdens will aid in the goal toward achieving affordability and, in turn, increase participation rates of UGI's CAP. On May 21, 2020, UGI filed a petition requesting to modify its USECP to reduce its maximum PIP rate.[83] In this petition, the Company sought to update its USECP to reflect the Commission's revised CAP Policy Statement,[84] including adopting the Commission's maximum CAP energy burden standards of 4% for customers with income at or below 50% FPL and 6% for customers with income between 51-150% FPL. While UGI's petition is currently pending at a separate docket, I recommend that UGI be required to implement the reduced maximum energy burden standards proposed therein as a condition to approval of any rate increase in this proceeding. Reducing the maximum CAP energy burden thresholds in this proceeding will help to address and remediate deep rate unaffordability for low income customers at both existing and proposed rates.

Q: Do you have additional recommendations that will help improve UGI's CAP participation rate?

A: Yes. I recommend that UGI take the following steps to help increase CAP participation and ensure that the program reaches more customers in need of assistance:

- ***UGI should simplify enrollment in CAP for non-CAP Low Income Home Energy Assistance Program (LIHEAP) recipients.***

In the Settlement for its 2020 rate case, as a temporary measure in response to the COVID-19 pandemic, UGI agreed to conduct enhanced customer screening to determine CAP and LIHEAP eligibility, to auto-enroll non-CAP LIHEAP recipients in CAP, and to generate pre-populated

[83] UGI Addendum to 2020-2025 USECP, Docket No. M-2017-2598190, May 1, 2020 (UGI PIP Petition).
[84] 52 Pa. Code § 69.261 et seq.

LIHEAP applications for non-LIHEAP CAP customers.[85] Although these policies were adopted by UGI as temporary emergency-based changes to address the COVID-19 pandemic, these policies continue to be vital to help ensure that low income customers are able to access all needed assistance programs for which they are eligible. Specifically, LIHEAP recipients have already submitted documentation to the Pennsylvania Department of Human Services (DHS) verifying that their income is at or below 150% FPL.[86] They should not be forced to jump through additional unnecessary hoops to submit that same documentation to enroll in CAP, which has the same income requirements.

I recommend that, within 180 days of a final order in this case, UGI establish a simplified process for non-CAP LIHEAP recipients to enroll in CAP similar to the process established pursuant to the 2020 rate case settlement. To that end, within 90 days of a final order in this case, UGI should survey all non-CAP LIHEAP recipients to better understand why they have not enrolled in CAP and include a prepopulated CAP application with the survey. UGI should present the results of the survey to its Universal Service Advisory Committee to gather input and suggestions for how to effectively streamline cross-program enrollment while avoiding potential unintended consequences.

Additionally, to help leverage additional LIHEAP funds, I also recommend that UGI reinstitute its practice of generating pre-populated LIHEAP applications for all non-LIHEAP CAP customers.

[85] Pa. PUC v. UGI, R-2019-3015162, Joint Pet. for Settlement at ¶ 27(c)(ii) (submitted Aug. 3, 2020).
[86] Pennsylvania Low Income Home Energy Assistance Program (LIHEAP) 2022 State Plan, available at: https://www.dhs.pa.gov/Services/Assistance/Documents/Heating%20Assistance_LIHEAP/2022%20LIHEAP%20State%20Plan_FINAL%20Approved.pdf

- ***UGI should refer all customers that call seeking a payment arrangement to apply for CAP and other Universal Service Programs and should actively assist with enrollment.***

It is unclear whether and how UGI is currently referring customers seeking a payment arrangement to apply for available universal service programs. In 2020, UGI reported 9,835 confirmed low income customers were in payment arrangements attempting to pay down approximately $19.5 million dollars in debt.[87] These confirmed low income customers represented approximately 77% of residential customers on payment arrangements and 95% of all residential dollars in debt on a payment arrangement.[88] The Public Utility Code specifically requires that whenever customer or applicant contacts a public utility to make a payment agreement, the public utility must, "[r]efer the customer or applicant to the universal service program administrator of the public utility to determine eligibility for a program and to apply for enrollment in a program."[89] The utility must also, "[p]rovide information about the public utility's universal service programs, including a customer assistance program."[90]

When a customer falls behind on their bill or an applicant is denied service due to an outstanding balance, their first instinct is often to call the utility and request a payment arrangement. These customers may be newly low income as a result of a financial set back and unaware that they qualify for CAP and/or other universal service programs, which will help address their arrearage and reduce their monthly bill.

UGI should be required to screen household income of all residential customers who call requesting a payment plan and should refer potentially income-eligible customers to apply for CAP

[87] 2020 Universal Service Report at 11, 30.
[88] Id. (Dollars in Debt on an Arrangement: UGI reports $20,498,260 residential and $19,462,068 confirmed low income.).
[89] 66 Pa. C.S. §1410.1(2).
[90] 66 Pa. C.S. §1410.1(1).

and other universal service programs before entering a payment arrangement. To streamline the referral process, UGI should either assist the customer to enroll in a universal service program over the phone or should provide a "warm transfer" to UGI's universal service program administrator to complete the application process. UGI should develop call scripts and call center training to implement this referral process and ensure that low income customers who request a payment plan are provided information, referred to, and assisted to enroll in universal services programs. Additionally, customers at risk of termination who are transferred through this warm referral process should have a hold placed on termination while the CAP application is pending.

- ***UGI should conduct outreach to all customers who have been removed from CAP for failure to recertify income since the expiration of the Commission's Emergency COVID-19 Order.***

As I explained above, UGI suspended CAP recertifications for the duration of the Commission's COVID-19 Emergency Order.[91] Subsequently, when UGI's recertification requirements resumed, nearly 3,000 (12%) of CAP customers were removed from CAP for failure to recertify in a single year.[92] These removals had a significant impact on UGI's CAP enrollment, which dropped from 24,241 in January 2021 to 22,025 in December 2021 - a 9% annual reduction.[93] The large number of CAP removals also negatively impacted UGI's CAP participation rate, which dropped from 31% in 2020 to 28% in 2021. I recommend that UGI conduct affirmative outreach to all households that have been removed from CAP for failure to recertify and encourage them to reapply. UGI should conduct initial outreach via telephone calls and text messages and should send follow up letters with postage-paid envelopes for customers to more easily complete

[91] Pa. PUC v. UGI, R-2019-3015162, Joint Pet. for Settlement at ¶ 27(c)(ii).
[92] OCA to UGI II-16.
[93] Id. at II-15, Attach.

the income recertification requirements. UGI should also coordinate with their Universal Service Advisory Group for additional recommendations to reach these customers.

For those who successfully complete recertification and can show that they had received LIHEAP or were otherwise eligible for CAP on the date of their removal, UGI should recertify CAP enrollment back to the date of program removal – allowing households to receive retroactive bill subsidy and arrearage forgiveness for the time between removal and recertification.

b. Low Income Usage Reduction Program (LIURP)

Q: Please briefly describe the aspects of UGI's LIURP that you wish to address.

A: UGI's LIURP is a critical universal service program designed to improve bill affordability, reduce arrearages and termination rates over the long term, and work in tandem with CAP to help reduce uncontrollably high usage attributable to home energy inefficiencies that low income households cannot afford to address on their own.[94] Throughout Pennsylvania, natural gas heating customers who receive LIURP services achieve annual bill savings that average approximately $304 per year - or roughly 16.6%.[95] In 2019, UGI's average bill savings per LIURP job was 20-25%.[96] Bill reductions through comprehensive energy efficiency and conservation efforts improve affordability and help to ensure that low income customers remain connected to service at more affordable rates.

Despite the value of UGI's LIURP and its impressive results, UGI's LIURP is not operating at a rate sufficient to fulfill the estimated need for comprehensive usage reduction services within a reasonable amount of time.[97] In 2021, LIURP services were provided to just 378 households

[94] 52 Pa. Code § 58.1; 2020-2025 USECP at 25.
[95] 2020 Universal Service Report at 56-57.
[96] CAUSE-PA to UGI II-16.
[97] CAUSE-PA to UGI I-13.

across its service territory.[98] According to UGI's most recent LIURP needs assessment, it will take several decades to serve identified needs across its service territory.[99] In UGI's former South District, it would take 25 years to serve estimated need; while in UGI's former North District, it would take an estimated 40 years to serve those in need.[100] Despite this overwhelming unmet need for services, UGI has historically underspent its LIURP budget in each geographic region.[101] In 2021, UGI had over $1 million left in its LIURP budget across its three rate divisions.[102]

LIURP services are critical to assisting low income households to move toward energy affordability by improving their energy efficiency and reducing their monthly bills, and it is critical that UGI fully expend available LIURP funds and allocate additional needed funding to meet the needs of its low income customers who are currently in need of weatherization and energy efficiency services.

Q: Do you have recommendations that would help UGI's LIURP program reach a greater number of homes in need of service?

A: Yes. I recommend that UGI reduce its LIURP minimum usage threshold for households at or below 150% FPL. I also recommend that UGI increase its annual LIURP budget by a percentage at least equal to the average residential bill impact of any approved residential rate increase. I will outline these recommendations in further detail below.

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[98] CAUSE-PA to UGI I-10, Attach.
[99] Id. at I-13(b) (The needs assessment was performed on two of the three UGI Gas territories. The former South District would take 25 years, and the former North District would take 40 years.).
[100] Id.
[101] CAUSE-Pa to UGI I-14.
[102] Id.

- ***UGI should lower its LIURP minimum usage threshold.***

The minimum usage threshold for eligibility for UGI's LIURP services requires that, in addition to meeting the income based eligibility criteria for the program, applicants must also have usage of at least 30% above the average usage for UGI customers.[103] However, many low income customers in need of usage reduction services may not meet this standard because they live in smaller homes and apartments. These customers may have lower overall usage than non-low income residential ratepayers – yet may still have relatively higher usage per square foot of living space. These customers would benefit from comprehensive usage reduction services because they have higher usage relative to the size of their home due to older inefficient housing stock.

In the Settlement for its 2020 rate case, UGI agreed to adjust its LIURP minimum usage threshold to help ramp up its LIURP production after months of installation delays due to the COVID-19 pandemic.[104] For the duration of its 2020 LIURP program year, UGI reduced its LIURP minimum usage threshold to reflect the average usage of residential customers (no longer average usage + 30%) for customers at or below 150% FPL.[105] In order to address the continued underspending of LIURP, I recommend that UGI continue this appropriate modification and adopt this reduced LIURP minimum usage threshold. This action will enable low income households who currently need to improve their energy efficiency and reduce their monthly bills be able to reduce and manage their consumption in a cost effective manner.

[103] 2020-2025 USECP at 26.
[104] Pa. PUC v. UGI, Docket No. R-2019-3015162, Joint Pet. for Settlement at 13 (submitted August 3, 2020).
[105] Id.

- ***At a minimum, UGI should increase its annual LIURP budget commiserate with any approved residential rate increase.***

To address the gap between need and available budget, and to help mitigate the impact of the rate increase on low-income families with uncontrollably high usage, I recommend that – at a minimum – UGI should be required to increase its overall LIURP budget by a percentage equal to the percentage increase of any approved residential rate increase. I recommend that these additional funds be targeted proportionally to the existing need in each UGI service district to even out the timeframe for addressing the existing need identified in UGI's needs assessment between the North and South districts.

As proposed, UGI's residential rate hike will increase the bill of a residential customer with average usage from $98.62 to $108.01 per month, or by 9.5%.[106] The Company's current total LIURP budget is $3,705,350.[107] Thus, if UGI's rates were approved as proposed, UGI's LIURP budget should be increased, at a minimum, by 9.5% or $352,008 – distributed proportionally according to the existing need in UGI's former North, South, and Central rate districts.

c. Operation Share

Q: Please briefly describe the aspects of UGI's Operation Share that you wish to address.

A: In response to the COVID-19 pandemic, UGI made several temporary adjustments to its universal service programs, including the provision of an additional $2 million in funding for the Operation Share program, expanded income eligibility up to 250% FPL, and increased the maximum grant size from $400 to $600.[108] Subsequently, Operation Share grants increased by

[106] UGI St. 1 at 7.
[107] CAUSE-PA to UGI IV-3.
[108] UGI St. 1 at 13; see also Pa. PUC v. UGI, R-2019-3015162, Joint Pet. for Settlement at ¶ 28(c).

605%, from 1,034 grants totaling $302,179 in 2019 to 5,192 grants totaling $2,130,738 in 2021.[109] However, since the expiration of the Commission's Emergency COVID-19 Order, the program has not been effective at curbing the dramatic increase in low income termination rates.

Despite the availability of additional Operation Share funds and the increase in the number of grants awarded, UGI low income customers still experienced a disproportionate increase in termination rates. As I explained above, in 2021, UGI's confirmed low income termination rate was more than double its 2019 rate and its CAP termination rate was more than triple 2019 levels, while UGI's general residential termination rate remained in line with 2019 levels.[110] At the end of the 2021-2022 winter moratorium, 7% of confirmed low income customers and 23% of CAP customers were at risk of termination, compared to only 5% of residential customers as a group.[111] This disproportionate increase in low income termination rates occurred despite the fact that the Operation Share program was carrying a significantly increased budget throughout 2021. As of January 2022, $1,916,100 remained in the Operation Share Budget, which is nearly quadruple the amount carried through all of 2019.[112] The significant amount of unspent Operation Share funds remaining in the Operation Share Budget, despite the high termination rates amongst confirmed low income and CAP customers, highlights the need for substantial improvements in UGI's targeting and disseminating these grants.

Q: Do you have any recommendations regarding UGI's Operation Share Program?

A: Yes. I recommend that UGI take additional steps to refocus the Operation Share program to address the steep increase in low income termination rates and more appropriately target its

[109] UGI St. 1 at 14.
[110] CAUSE-PA to UGI I-3, I-4, I-7, I-8, I-9, I-17.
[111] See CAUSE-PA to UGI IV-8; see also OCA to UGI II-17 (confirmed low income count as of Jan. 2022); OCA to UGI II-15 (CAP customer count as of Feb. 2022), Attach; CAUSE-PA to UGI I-17 (residential customer count as of Jan. 2022).
[112] CAUSE-PA I-26 (a), Attach.

Operation Share grants to help customers most in need of assistance. I will discuss each of these recommendations in detail below.

- ***Increase the maximum grant amount for customers at or below 150% FPL.***

I recommend that UGI increase the maximum grant amount available to low income households at risk of termination. In furtherance of the explicit statutory purpose of CAP to assist low income customers to maintain gas service to their home,[113] I recommend that UGI increase the maximum grant amount for customers at risk of termination in the lowest income tiers to ensure that customers with least ability to pay are provided the most assistance. Thus, I recommend that the maximum grant amounts be increased to $600 for customers with income 101-150% FPL, $700 for customers with income 51-100%, and $800 for customers with income at or below 50% FPL.

- ***UGI should increase its annual Operation Share contribution by an amount that is at least proportional to its residential rate increase.***

As explained above, low income customers already struggle to afford service and are at a greater risk of service termination compared to general residential customers. Any increase to the cost of essential utility service, such as UGI's currently proposed rate increase, will worsen these struggles and lead to an increased threat of termination for these customers. Thus, I recommend that UGI make additional Operation Share funds available that are, at a minimum, proportional to any rate increase approved in this proceeding. UGI's low income termination rates are soaring, and the currently available funds could quickly be depleted if this trend continues. Increasing the Company's annual Operation Share contributions at a percentage that is at least commensurate with the percentage of any residential bill increase that may result from this proceeding will help

[113] See 66 Pa. C.S. § 2202 (Definition of "Universal Service and Energy Conservation").

the program budget better keep pace with the cost of residential service and that the policies, protections, and services which are currently in place to avoid termination are not as significantly reduced as a result of any potential rate increase.

III. PROPOSED RATE DESIGN

Q: Please briefly describe the aspects of UGI's residential rate design proposal that you wish to address.

A: Through this proceeding, UGI seeks to increase its fixed monthly residential customer charge from $14.60 to $19.95, an increase of $5.35 or 36.6%.[114] UGI also proposes a Weather Normalization Adjustment (WNA), which is designed to decouple UGI's sales revenue from changes in weather.[115]

a. Fixed Customer Charge

Q: How would UGI's proposed increase to its fixed monthly residential customer charge impact low income households?

A: This level of increase to the fixed charge will undermine the ability of consumers to control costs through energy efficiency, conservation, and consumption reduction, which is particularly problematic for low-income customers who already struggle to pay for natural gas service and rely on offsetting high bills through careful conservation and usage reduction.

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[114] UGI St. 8 at 20.
[115] UGI St. 10 at 6.

Q: Would UGI's proposed increase to the fixed charge affect the Company's LIURP program?

A: Yes. UGI's proposal undermines the explicit goals of the Low-Income Usage Reduction Program (LIURP) to "reduce residential energy bills." [116] By reducing the amount of bill reduction that can be obtained through LIURP measures, the proposed increase to the fixed charge threatens the continued effectiveness of ratepayer investments intended to reduce energy consumption, delinquencies, collections, and uncollectible costs. Thus, the proposed increase to the fixed charge will, in turn, impact the ability of LIURP to "decrease the incidence and risk of customer payment delinquencies and the attendant utility costs associated with uncollectible accounts expense, collection costs and arrearage carrying costs."[117] This would be a perverse and unreasonable result. LIURP is a statutorily mandated program to be provided by the Companies to help low income customers reduce or manage their energy consumption in a cost-effective manner. Any increase to the fixed charge would both undermine the goal of LIURP and make the existing program less cost effective.

As explained above, UGI's LIURP is effective at achieving these goals and producing meaningful average bill savings of 20-25% for the low income households who have been able to receive services.[118] The ability to save money through energy efficiency is tied directly to a bill structure that bases costs on throughput. But as more residential customer costs are shifted to the fixed charge, the achievable bill savings – and the corresponding impact on bill payment behavior – will erode.

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[116] 52 Pa. Code § 58.1 ("The programs are intended to assist low-income customers conserve energy and reduce residential energy bills. The reduction in energy bills should decrease the incidence and risk of customer payment delinquencies and the attendant utility costs associated with uncollectible accounts expense, collection costs and arrearage carrying costs.").
[117] Id.
[118] CAUSE-PA to UGI II-16.

The current customer charge ($14.60) makes up approximately 14.8% of the current average residential bill ($98.62).[119] If UGI's proposed rate increase and fixed customer charge are approved, the $19.95 fixed charge would equal approximately 18.5% of the average bill ($108.01).[120] In other words, if the proposed increase in the fixed customer charge is approved, UGI customers will lose the ability to control (on average) as much as 3.7% of their monthly bill ($48.00 annually based on UGI's proposed $108.01 average monthly bill) through energy conservation and consumption reduction efforts. Thus, the effect of the increased fixed charge would reduce the effectiveness of LIURP to achieve meaningful bill savings for low income consumers.

The ability to achieve bill savings through energy efficiency and conservation measures is especially important for households with income above 150% but less than 200% of poverty who are ineligible for CAP or LIHEAP but are eligible for energy efficiency and conservation services through LIURP or the federal Weatherization Assistance Program (WAP) – both of which have income guidelines of up to 200% FPL. These households need to retain the ability to reduce their monthly energy costs through adoption of comprehensive energy efficiency and conservation programming.

Given low income households are disproportionately at risk of termination and often lack the ability to control usage due to poor housing stock and older, less efficient appliances,[121] it is critical that they continue to have access to effective conservation tools capable of producing meaningful and lasting bill reductions. Additionally, UGI's high fixed charge proposal will

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[119] See UGI St. 1 at 7; UGI St. 8 at 20.
[120] See Id.
[121] See ACEEE, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-income and Underserved Communities (April 2016), available at: https://www.aceee.org/sites/default/files/publications/researchreports/u1602.pdf.

undermine the millions of ratepayer dollars that UGI is authorized to invest in energy efficiency through its voluntary Energy Efficiency and Conservation Program Plan.

Q: Do you have any recommendations that could help mitigate the effect of the proposed rate design on low-income households?

A: Yes. UGI's fixed monthly customer charges should not be increased. To the extent any increase in UGI's residential distribution rate is approved, it should be applied to the volumetric charge. This would protect the ability of low income households to lower their utility costs by reducing consumption and would preserve the effectiveness of the LIURP program at reducing customer bills and improving payment behavior.

b. Weather Normalization Adjustment (WNA)

Q: Please briefly describe the UGI's proposed WNA.

A: UGI's proposed WNA is a bill adjustment applied to certain customer classes (including residential customers) during the winter heating months that attempts to break the link between the revenue collected through the volumetric rate and the effects of variations in temperature.[122] UGI claims that the WNA would protect the utility from reduced revenue due to warmer weather and would protect customers from higher bills due to colder than normal weather.[123] However, in practice, WNAs implemented in other service territories have resulted in higher charges for residential consumers and shifted all risk of changing weather from utilities onto consumers.[124]

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[122] UGI St. 10 at 6.
[123] Id.
[124] See Pa. PUC v. Columbia Gas of Pa., Inc., R-2020-3018835, Columbia St. 3 at 17-18 (submitted Apr. 24, 2020); See also Pa. PUC v. Philadelphia Gas Works, R-2017-2586783, PGW Annual WNA Reporting (filed Dec. 31, 2019; June 9, 2021; Jan. 6, 2022).

Q: Why do WNAs result in consistently higher bills for residential customers?

A: Utility distribution rates are based on expected throughput during normal weather. When temperatures are warmer than normal, which they have been for the last several years, WNAs result in a higher bill for residential customers. In 2019, 2020, and 2021, the weather in UGI's service territory, was 3%, 9% and 9% warmer than normal, respectively.[125] If UGI's WNA had been in place, the automatic charge would have increased residential bills every year over the past five years.[126] Table 4 shows UGI's estimated annual impact of the WNA to residential customers over the past five years at current rates:

Table 4: WNA Analysis - Estimated Impact to R/RT Customers at Current Rates[127]

Fiscal Year	Estimated Annual Impact to R/RT Customer at Current Rates
2017	$39.05
2018	$7.81
2019	$6.17
2020	$35.35
2021	$29.59

Q: Do you support adoption of the WNA in this proceeding?

A: No. UGI's proposed WNA would prevent residential customers from realizing bill savings that result from warming weather trends and would shift all weather-related risk from the utility to the consumer. Low income customers struggle to afford service and need to retain every ability to

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[125] OCA to UGI VI-3; see also Pa. Dep. of Enviro. Protect'n, Pa. Climate Impacts Assessment 2021, (published May 202, revised July 28, 2021), available at: http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=3667348&DocName=PENNSYLVANIA%20CLIMATE%20IMPACTS%20ASSESSMENT%202021.PDF%20%20%3cspan%20style%3D%22color:green%3b%22%3e%3c/span%3e%20%3cspan%20style%3D%22color:blue%3b%22%3e%28NEW%29%3c/span%3e%204/30/2023 .

[126] CAUSE-PA to UGI II-10.

[127] Id., Attach.

realize bill savings due to reduced usage, even reduced usage due to changing weather patterns. As I explained earlier, approximately half of UGI's CAP customers are charged a CAP rate relative to their average bill which has been based upon usage and would lose the opportunity to recognize bill savings resulting from reduced usage during warmer than normal winters.

Residential customers will receive no practical benefit from implementation of the WNA. Any risk of increased bills due to colder than normal winters is outweighed by the increasing frequency of warmer winters. Further, the risk of varying bills due to colder than normal winters can be mitigated by enrollment in CAP or budget billing. While UGI touts that the WNA will produce more predictable bills, a more predictable but less affordable bill will not benefit low income customers who already struggle to afford service. Thus, I recommend that the Commission reject UGI's proposed WNA.

IV. <u>LATE FEES AND RECONNECTION FEES</u>

Q: Please briefly describe UGI's late fees and reconnection fees.

A: If a customer falls behind on their bill, UGI charges 1.5% per month on the overdue portion of the bill.[128] This is the maximum allowed under the Commission's regulations.[129] The overdue charges continue to accrue interest until either the overdue balance is satisfied or until the final bill is produced post termination.[130] If the customer falls so far behind on their bill that UGI terminates service for nonpayment, UGI charges an additional $73.00 to reconnect that customer.[131]

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[128] UGI Tariff at 43.
[129] 52 Pa. Code §56.22(a)
[130] CAUSE-PA to UGI III-4.
[131] UGI Tariff at 46.

Q: How do late fees and reconnection fees affect low income consumers?

A: When a customer cannot afford to pay their bill, late fees function as a punitive measure, punishing those who fall behind because they are unable to afford their bills – not because they are unwilling to pay. Late fees in turn add additional costs to arrears that the customer already cannot afford to pay, which contributes to the high rate of low income terminations.[132] These regressive charges disproportionately impact low income households who cannot afford their monthly bill and, more specifically, disproportionately impact low income Black and Hispanic households, families with young children, and medically vulnerable households – all of whom are more likely to face utility insecurity.[133]

Like late fees, reconnection fees also add a substantial barrier to reconnection, resulting in low income customers experiencing longer periods of time without service. The average income for UGI's confirmed low income customers is $12,084, or just $1,007 per month.[134] UGI is proposing to increase total bill for the average residential heating customer from $98.62 to $108.01 per month, which would raise the natural gas bill burden for these customers from 9.8% to 10.7%, not including the additional burden of their electric bill. [135] If these customers are unable to pay and are subsequently terminated, UGI's $73.00 reconnection charge requires that they pay additional 7.2% or their monthly income to reconnect to service.

As I explained above, loss of natural gas service has a deep and lasting impact on the health and wellbeing of the entire household and the community as a whole, and is a common catalyst to

[132] Jasen Lo, Food or power: Energy bill late fees force tough choices, AP News, March 14, 2022, available at: https://apnews.com/article/energy-late-fees-Louisiana-Kentucky-da59030e9abc8b5271b4a13eee15f63d .
[133] Memmott, T., Carley, S., Graff, M. et al. Sociodemographic disparities in energy insecurity among low-income households before and during the COVID-19 pandemic. Nat Energy 6, 186–193 (2021), available at: https://doi.org/10.1038/s41560-020-00763-9 .
[134] CAUSE-PA to UGI I-15.
[135] UGI St. 1 at 7.

homelessness.[136] When families are unable to use a primary heating system, they often resort to dangerous heating methods that increase the risk of carbon monoxide poisoning and house fires.[137] UGI's reconnection fee increases those risks by adding additional barriers to the ability of households to reconnect to service, thus increasing the amount of time households may remain without a functioning primary heating system.

Q: Do you have any recommendations regarding UGI's late fees and reconnection fees?

A: Yes. I recommend that UGI stop charging late fees and reconnection fees to low income customers. I note that the Commission has prohibited utilities from charging security deposits to low income households due to the detrimental effect they have on those customers' ability to connect or reconnect to service.[138] UGI's late fees and reconnection fees raise similar barriers for low income customers seeking to establish and maintain affordable natural gas service in their homes. It is unjust and unreasonable to continue to penalize low income customers for not being able to pay bills that they cannot afford to pay, terminating service based on nonpayment of those charges, and ultimately adding even more charges to the bill for reconnection.

V. SUMMARY OF RECOMMENDATIONS

Q: Please summarize your recommendations.

A: I have made several recommendations throughout my testimony to address current levels of unaffordability and mitigate the financial impact of any approved rate increase on low-income

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[136] See Joint State Government Commission, General Assembly of the Commonwealth of Pennsylvania, Homelessness in Pennsylvania: Causes, Impacts, and Solutions: A Task Force and Advisory Committee Report (2016), available at: http://jsg.legis.state.pa.us/resources/documents/ftp/documents/HR550%201%20page%20summary%204-6-2016.pdf.

[137] Richard Campbell, Home Heating Fires, National Fire Protection Association (NFPA), (Jan. 2021), available at: https://www.nfpa.org/News-and-Research/Data-research-and-tools/US-Fire-Problem/Heating-equipment

[138] See 52 Pa. Code § 56.32(e).

households. Specifically, I recommend that UGI take the following steps to strengthen and reform UGI's universal service programming to more effectively reach and serve low income customers:

- Adopt a process for simplified enrollment in CAP for Non-CAP Low Income Home Energy Assistance Program (LIHEAP) recipients.
- Inquire about the household income level of all customers seeking payment arrangements and provide a "warm transfer" for all potentially eligible customers to apply for CAP and other universal service programs.
- Conduct outreach to all customers who have been removed from CAP for failure to recertify since the expiration of the Commission's Emergency COVID-19 Order.
- Lower the minimum usage threshold to access energy efficiency and usage reduction services through LIURP.
- Increase the annual budget for LIURP commiserate with residential rate increase to help reduce energy usage in low income homes.
- Increase the maximum Operation Share grant amount for customers with income at or below 150% FPL.
- Increase the annual Operation Share contribution proportional to residential rate increase.

In addition to the above recommendations regarding UGI's universal service programming, I also recommended that the Commission:

- Reject UGI's proposed increase to its fixed customer charge.
- Reject UGI's proposed WNA.
- Prohibit UGI from assessing late fees and reconnection fees to confirmed low income customers.

Q: Does this conclude your direct testimony?

A: Yes.

THE COALITION FOR AFFORDABLE UTILITY SERVICE AND ENERGY EFFICIENCY IN PENNSYLVANIA

APPENDIX A

RESUME OF HARRY S. GELLER

RESUME OF HARRY S. GELLER

EDUCATIONAL BACKGROUND:

Harpur College, State University of New York at Binghamton, B.A. 1966
Washington College of Law, American University, J.D. 1969
New York University Law School, courses in Urban Affairs and Poverty Law, as part of Volunteers in Service to America (VISTA) Program 1969-1971

EMPLOYMENT:

1988 – 2015 Executive Director, Pennsylvania Utility Law Project (PULP), a project of the civil non-profit Pennsylvania Legal Aid Network. PULP is dedicated to providing technical support, information sharing, and representation to low-income individuals and organizations, assisting and advocating for the low income in utility and energy matters. Responsibilities include project oversight, case consultation, co-counseling, and participation on task forces, work groups and advisory panels, community education and training in utility and energy matters affecting the low income.

While at PULP, served in the following capacities:

- Chairman, Low-Income Home Energy Assistance Program (LIHEAP) Advisory Committee to the Secretary, Pennsylvania Department of Human Services
- Member, Pennsylvania Public Utility Commission, Consumer Advisory Council Coordinator, Pennsylvania Legal Services Utility/Energy Work Groups
- Member, Weatherization Policy Advisory Committee to the Department of Community and Economic Development
- Member, PECO Universal Service Advisory Committee and LIURP Subcommittee

1974-1987 Staff Attorney, Managing Attorney and ultimately, Executive Director of Legal Services, Incorporated (LSI), a civil legal services program serving Adams, Cumberland, Franklin and Fulton Counties. Through a restructuring with other legal services programs, LSI became part of what is now known as MidPenn Legal Services and Franklin County Legal Services.

1971-1972 Staff Attorney, New York City Legal Aid Society, Criminal Court and Supreme Court Branches, New York County.

1969-1971 Volunteer in Service to America (VISTA) assigned to the New York University Law School Project on Urban Affairs and Poverty Law.

BAR ADMISSIONS

New York State
Commonwealth of Pennsylvania
United States District Court, Middle District of Pennsylvania

Cases in which Harry S. Geller has participated as a witness before the Pennsylvania Public Utility Commission since July 1, 2015

- Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company for Approval of their Default Service Programs for the period commencing June 1, 2023, through May 31, 2027, P-2021-3030012, P-2021-3030013, P-2021-3030014, P-2021-3030021
- Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc., Docket Nos. R-2021-3027385, R- 2021-3027386.
- Pennsylvania Public Utility Commission v. Pittsburgh Water and Sewer Authority, R-2021-3024773, R-2021-3024774, R-2021-3024779.
- Pennsylvania Public Utility Commission v. Duquesne Light Company, R-2021-3024750.
- Pennsylvania Public Utility Commission v. PECO Energy – Electric Division, R-2021-3024601.
- Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc., R-2021-3024296.
- Tenant Union Representative Network v. PECO Energy Company, C-2020-3021557
- Pennsylvania Public Utility Commission v. Philadelphia Gas Works, R-2020-3017206.
- Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program for the Period of June 1, 2021 through May 31 , 2025, Docket No. P-2020-3019356.
- Petition of PECO Energy Company for Approval of Its Default Service Program for the Period from June 1, 2021 through May 31, 2025, Docket No. P-2020-3019290.
- Petition of Duquesne Light Company For Approval of Default Service Plan For The Period June 1, 2021 Through May 31, 2025, Docket No. P-2020-3019522.
- Joint Application of Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC and Peoples Gas Company LLC for all of the Authority and Necessary Certificates of Public Convenience to Approve a Change in Control of Peoples Natural Gas Company LLC, and Peoples Gas Company LLC by way of the Purchase of all of LDC Funding LLC's Membership Interests by Aqua America, Inc., Docket Nos. A-2018-3006061, A-2018-3006062, A-2018-3006063.
- Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc. et al. Docket Nos. R2018-3003558 et seq.
- Pennsylvania Public Utility Commission v. Duquesne Light Company, Docket No. R-2018-3000124.
- Pennsylvania Public Utility Commission v. PECO Energy Company- Electric Division, Docket No. R-2018-3000164.
- Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company,
- Pennsylvania Power Company, and West Penn Power Company for Approval of their Default Service Programs for the period commencing June 1, 2019 through May 31,

2023, Docket Nos. P-2017-2637855, P-2017-2637857, P-2017-2637858; P-2017-2637866.

- Pennsylvania Public Utility Commission et al. v. Philadelphia Gas Works, Docket No. R-2017-2586783.
- PECO Energy Company's Pilot Plan for an Advance Payments Program and Petition for Temporary Waiver of Portions of the Commission's Regulations with Respect to that Plan, Docket No. P-2016-2573023.
- Petition of PECO Energy Company for Approval of a Default Service Program for the Period of June 1, 2017 through May 31, 2019, Docket No. P-2016-2534980.
- Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period of June 1, 2017 through May 31, 2021, Docket No. P-2016-2526627.
- Petition of Duquesne Light Company for Approval of a Default Service Program for the Period of June 1, 2017 through May 31, 2021, Docket No. P-2016-2543140.
- Pennsylvania Public Utility Commission et al. v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2016-2529660.
- Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company,
- Pennsylvania Power Company, and West Penn Power Company for Approval of their Default Service Programs for the period commencing June 1, 2017 through May 31, 2019, Docket Nos. P-2015-2511333, P-2015-25113351, P-2015-2511355, P-2015-2511356.
- Petition of PPL Electric Utilities Corporation for Approval of its Energy Efficiency and Conservation Plan, Docket No. M-2015-2515642.

THE COALITION FOR AFFORDABLE UTILITY SERVICE AND ENERGY EFFICIENCY IN PENNSYLVANIA

APPENDIX B

CITED DISCOVERY RESPONSES

Coalition of Affordable Utility Service and Energy Efficiency in Pennsylvania (CAUSE-PA) directed to UGI Utilities, Inc. – Gas Division (UGI)

- CAUSE-PA to UGI I-1
- CAUSE-PA to UGI I-7, Attachment.
- CAUSE-PA to UGI I-8, Attachment.
- CAUSE-PA to UGI I-9.Attachment
- CAUSE-PA to UGI I-10, Attach
- CAUSE-PA to UGI I-12, Attachment.
- CAUSE-PA to UGI I-13 Attachment
- CAUSE-Pa to UGI I-14.
- CAUSE-PA to UGI I-15,
- CAUSE-PA to UGI I-16
- CAUSE-PA to UGI I-17 Attach.
- CAUSE-PA I-26 (a), Attach.
- CAUSE-PA to UGI II-10, Attach.
- CAUSE-PA to UGI II-16.
- CAUSE-PA to UGI III-4.
- CAUSE-PA to UGI IV-1.
- CAUSE-PA to UGI IV-2.
- CAUSE-PA to UGI IV-3.
- CAUSE-PA to UGI IV-8
- CAUSE-PA to UGI IV-14, Attach

Office of Consumer Advocate (OCA) directed to UGI Utilities, Inc. – Gas Division (UGI)

- OCA to UGI II-15, Attachment.
- OCA to UGI II-16, Attach.
- OCA to UGI II-17,
- OCA to UGI II-18
- OCA to UGI VI-3.

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-1

Request:

Please identify the financial impact of the proposed increase on customers enrolled in UGI's Customer Assistance Program (CAP) by payment plan type. If you are unable to identify the financial impact, or assert that there will be no impact, please explain.

Response:

As stated in the Company's Universal Service and Energy Conservation Plan ("USECP"), which has been provided in the Company's February 5, 2020 filing at Docket No. M-2017-2598190 available on the Public Utility Commission's website, the Company's CAP participants pay a monthly CAP amount based on a percent of income, or, if the percent of income payment is greater than their average bill, the CAP participant pays a monthly CAP amount equal to their average bill. Notwithstanding the foregoing, a CAP Customer's minimum monthly payment is set at a floor of $25 for heating accounts and $15 for non-heating accounts. A CAP participant's monthly payment is fixed until the participant recertifies income (at which time it is determined whether the monthly payment amount should change).

The Company's proposed rate increase will not impact CAP payments set at a percent of income or a minimum payment. However, as of the date of this response, approximately 51% of UGI CAP customers have their CAP payment set at their average monthly bill. Upon income re-certification, these average monthly bill CAP payments could be impacted in an amount up to the approved rate increase. Also, no CAP Customer would pay more than their applicable percentage of income calculation, set forth in the Company's USECP.

As a result, UGI is unable to estimate the impact of the proposed rate increase to CAP participant's payment amounts.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-4

Request:

From 2019 to date, disaggregated by month, how many of UGI's customers were/are enrolled in CAP?

Response:

Please see the response to OCA-II-15.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-7

Request:

How many residential customers had their service terminated for non-payment in calendar years 2019, 2020, 2021 and to date in 2022, disaggregated by month?

Response:

Please see Attachment CAUSE-PA-I-7.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division

MONTH	RESIDENTIAL TERMINATIONS
Jan-19	1
Feb-19	103
Mar-19	113
Apr-19	6,406
May-19	4,087
Jun-19	1,110
Jul-19	923
Aug-19	1,644
Sep-19	839
Oct-19	4,356
Nov-19	1,230
Dec-19	1
Jan-20	34
Feb-20	141
Mar-20	141
Apr-20	0
May-20	0
Jun-20	0
Jul-20	0
Aug-20	0
Sep-20	0
Oct-20	0
Nov-20	0
Dec-20	40
Jan-21	168
Feb-21	68
Mar-21	126
Apr-21	818
May-21	4,602
Jun-21	5,136
Jul-21	2,887
Aug-21	2,992
Sep-21	2,612
Oct-21	1,830
Nov-21	1,774
Dec-21	0
Jan-22*	11

*Data as of 1/31/2022

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-8

Request:

How many confirmed low income customers had their service terminated for non-payment in calendar years 2019, 2020, 2021 and to date in 2022, disaggregated by month?

Response:

Please see Attachment CAUSE-PA-I-8.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division

MONTH	CONFIRMED LOW-INCOME TERMINATIONS
Jan-19	0
Feb-19	0
Mar-19	0
Apr-19	488
May-19	185
Jun-19	68
Jul-19	54
Aug-19	73
Sep-19	44
Oct-19	353
Nov-19	120
Dec-19	0
Jan-20	0
Feb-20	0
Mar-20	0
Apr-20	0
May-20	0
Jun-20	0
Jul-20	0
Aug-20	0
Sep-20	0
Oct-20	0
Nov-20	0
Dec-20	0
Jan-21	0
Feb-21	0
Mar-21	0
Apr-21	43
May-21	823
Jun-21	1,056
Jul-21	510
Aug-21	369
Sep-21	670
Oct-21	199
Nov-21	178
Dec-21	0
Jan-22*	0

* Data as of 1/31/22

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-9

Request:

How many CAP customers had their service terminated for non-payment in calendar years 2019, 2020, 2021 and to date in 2022, disaggregated by month?

Response:

Please see Attachment CAUSE-PA-I-9.

Prepared by or under the supervision of: Daniel V. Adamo

Attachment CAUSE-PA-I-9
D.V.Adamo
Page 1 of 1

UGI Utilities, Inc. - Gas Division

MONTH	CAP CUSTOMER TERMINATIONS
Jan-19	0
Feb-19	0
Mar-19	0
Apr-19	65
May-19	91
Jun-19	46
Jul-19	35
Aug-19	76
Sep-19	47
Oct-19	216
Nov-19	114
Dec-19	0
Jan-20	0
Feb-20	0
Mar-20	0
Apr-20	0
May-20	0
Jun-20	0
Jul-20	0
Aug-20	0
Sep-20	0
Oct-20	0
Nov-20	0
Dec-20	0
Jan-21	0
Feb-21	0
Mar-21	0
Apr-21	1
May-21	478
Jun-21	795
Jul-21	280
Aug-21	220
Sep-21	198
Oct-21	103
Nov-21	78
Dec-21	0
Jan-22*	0

*** Data through January 31, 2022**

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-10

Request:

How many LIURP jobs were completed by UGI Gas for calendar years 2018, 2019, 2020, 2021 and to date in 2022, disaggregated by year and division?

Response:

Please see Attachment CAUSE-PA-I-10.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division LIURP Jobs			
Year	**SOUTH**	**NORTH**	**CENTRAL**
2018	156	158	57
2019	166	164	67
2020	110	87	50
2021	178	122	78
2022*	22	15	8

* Data as of 1/31/2022

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 8, 2022

CAUSE-PA-I-12

Request:

For calendar years 2019, 2020, 2021 and to date in 2022 what was the average energy burden of CAP customers (including any arrearage forgiveness co-payment or any other additional fee or charge above the average bill), disaggregated by year, income level (0-50%, 51-100%, and 101-150% of the federal poverty level), and payment plan type?

Response:

Please see Attachment CAUSE-PA-I-12.

The Company is only able to provide the data as of the date queried out of the customer outreach system. The Company provided the two most recent average burden studies performed (2019 and 2021).

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division

UGI Utilities, Inc.

2019 Energy Burden by FPL and Payment Plan Type*			
Federal Poverty Level	Percent of Income	Average Bill	Min Bill
0%-50%	7.00%	5.28%	35.14%
51%-100%	8.00%	5.23%	Not Applicable
101%-150%	9.00%	4.62%	Not Applicable

*This data was previosuly submitted in 2020 Gas Base Rate Case. Data was based on the UGI Utilities, Inc. 2019 Energy Burden filing M-2017-2587711 and M-2017-2596907

UGI Utilities, Inc.

2021 Energy Burden by FPL and Payment Plan Type			
Federal Poverty Level	Percent of Income	Average Bill	Min Bill
0%-50%	7.00%	5.35%	15.15%
51%-100%	8.00%	5.21%	Not Applicable
101%-150%	9.00%	4.88%	Not Applicable

*This data was previously submitted following the Public Utility Commission Public Meeting held August 5th, 2021 - Re: Commission Clarification Regarding Supplemental Information and Filing Timeline Regarding the Commission's January 17, 2019 Order at Docket No. M-2017-2587711. The Energy Burden changes to comply with the CAP Policy statement required UGI file an Amended UGI Utilities, Inc. - Gas Division UGI Utilities, Inc. – Electric Division Universal Service and Energy Conservation Plan for 2020-2025, Docket No. M-2019-3014966.

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-13

Request:

Please provide UGI's most recent LIURP needs assessment approved by the Pennsylvania Utility Commission.

a. If UGI has prepared and submitted a needs assessment that has not yet been approved, please provide a copy.

b. Assuming that UGI treats an identical number of low income units as will be treated through LIURP in the current fiscal year, and assuming no unit will be retreated, please indicate the number of years it would take to treat 100% of the low income units identified in the above requested needs assessment(s).

Response:

Please see Attachment CAUSE-PA-I-13, pg. 43 Appendix B-1.

a. Not applicable.

b. The needs assessment was performed on two of the three UGI Gas territories. The former South District would take 25 years, and the former North District would take 40 years.

Prepared by or under the supervision of: Daniel V. Adamo

Energy to do more®

Danielle Jouenne, Esq.

UGI Corporation
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King of Prussia, PA 19406

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Valley Forge, PA 19482-0858

(610) 992-3203 Telephone (direct)

December 6, 2019

VIA ELECTRONIC FILING
Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Universal Service and Energy Conservation Plan for the Five-Year Period January 1, 2020 – December 31, 2025; Docket No. M-2017-2598190 et al.

Dear Secretary Chiavetta:

In a November 15, 2019 Secretarial Letter, UGI Utilities, Inc. ("UGI") was directed to file and serve a further revised 2020-2025 Universal Service and Energy Conservation Plan ("USECP") within 10 days to address the following two items:

1. Clarify that income received for the benefit of a minor is not considered by UGI as income of the adult. August 8 Order at 55.

2. Adjustments to reflect the provisions and duration of the temporary and partial waivers of Sections 58.10(a)(1) and 58.11(a) as those sections and waivers directly apply to UGI North's LIURP rules relative to residential customer's inoperable gas furnaces. August 8 Order at 60, 61.

The November 15, 2019 Secretarial Letter further encouraged UGI to consult with the Bureau of Consumer Services ("BCS") on the USECP revision prior to filing.

Subsequent to the November 15, 2019 Secretarial Letter, the Company requested, and received, a short extension until December 6, 2019 to file its USECP revisions. The Company consulted with BCS on the requested revisions to its USECP and the Company herein submits a final revised USECP. The changes to the USECP filed on October 24, 2019 are indicated in redline on pages 7, 17, and 18. The Company is also including with this filing a complete clean version of the USECP.

To address the request that UGI clarify that "income received for the benefit of a minor is not considered as income of the adult," this final revised USECP includes language clarifying that the Company does not consider unearned income of a minor in its calculation of household income for the purpose of CAP eligibility.

This final version also addresses the term of the LIURP waivers granted by the Commission's August 8, 2019 Order. The August 8, 2019 stated:

> Make appropriate adjustments to the UGI North revised USECP to reflect the approved waivers of Sections 58.10(a)(1) and 58.11(a) as those sections directly apply to UGI North's LIURP rules relative to residential customers' inoperable gas furnaces. These temporary waivers will expire in five years or with UGI North's next USECP, whichever is earlier, unless an extension is expressly requested by UGI North and granted by the Commission.

August 8, 2019 Order at p. 82.

As noted in the November 15, 2019 Secretarial Letter, the Company expanded this program to all UGI Gas customers upon the elimination of rate districts in its Gas Base Rate Proceeding at Docket No. R-2018-3006814. Subsequent to the August 8th Order, the Commission extended the term of this USECP to five (5) years.[1] If the Company's next USECP is not approved within five years, the waivers will expire, if not extended pursuant to the Company's request. To maintain program continuity, the Company therefore requests in this proceeding that the Commission extend the waiver of these LIURP regulations until the approval of UGI's next USECP.

The Company has served this filing on the active parties to this docket, namely the Office of Consumer Advocate ("OCA"), the Coalition for Affordable Utility Service and Energy Efficiency in Pennsylvania ("CAUSE-PA"), and the Commission on Economic Opportunity ("CEO"). The parties have all affirmatively represented that they have no objections to this final version of the Company's USECP.

Very truly yours,

Danielle Jouenne
Counsel for UGI

Enclosure
cc:

Eric Tuttle, BCS, *via email*, etuttle@pa.gov
Joseph Magee, BCS, *via email*, jmagee@pa.gov
Louise Fink Smith, Law Bureau, *via email*, finksmith@pa.gov
Certificate of Service

[1] By Order entered on October 3, 2019 at Docket No. M-2019-3012601 ("October 3rd Order"), the Pennsylvania Public Utility Commission granted temporary partial limited waivers of 52 Pa. Code §§ 54.74, 54.76 (a-b), 62.4, and 62.6 (a-b) to natural gas and electric distribution companies for the purpose of adhering to the 2020-2025 universal service and energy conservation plan and universal services impact evaluation filing schedule provided therein.

UGI Utilities, Inc. – Gas Division
UGI Utilities, Inc. – Electric Division

Universal Service & Energy Conservation Plan
For the Five-Year Period
January 1, 2020 – December 31, 2025

Docket No. M-2017-2598190

Filing Date: June 30, 2017
Revised: November 1, 2018
Revised: September 6, 2019
Revised: October 11, 2019
Revised: October 24, 2019
Revised: December 6, 2019

repair and replacement projects. Should there continue to be amounts to roll over after two years, any remaining roll over amounts will roll over to UGI Gas's general LIURP budget. The August 8th Order approved UGI's petition for waiver of LURP regulation payback requirement at 52 Pa. Code § 58.11(a) and the LIURP high-use criteria at 52 Pa. Code § 58.10(a)(1). Paragraph 19 of the August 8th Order provided that these temporary waivers will expire in five years or with the Company's next USECP, whichever is earlier, unless an extension is expressly requested by the Company and granted by the Comission. (August 8th Order, p. 82) Subsequent to the August 8th Order, the Commission extended the term of this USECP to five (5) years. To maintain program continuity, the Company therefore requests that the Commission grant waiver of these regulations until the approval of UGI's next USECP.

C. NEEDS ASSESSMENT

As required by 52 Pa. Code § 62.4(b)(3), at the time of initial filing, UGI South and UGI North rate districts submitted a needs assessment in Appendix B of this Plan. The needs assessment is based on 2010 census data and 2015 UGI Gas records. Pursuant to 52 Pa. Code §§ 54.77 and 62.7, EDCs and NGDCs with less than 100,000 residential customers are not required to submit a needs assessment; therefore, UGI Electric and the former UGI Central rate district did not submit a needs assessment. Future USECPs will provide needs assessments on a combined basis for UGI Gas.

III. THE CARES PROGRAM

A. DESCRIPTION OF THE CARES PROGRAM

1. Goals and Objectives

The goal of the CARES Program is to provide personal assistance and referrals to payment-troubled customers and to help improve their delinquent bill payment problems. The CARES Program identifies special needs customers and guides them to the appropriate program or agency. CARES concentrates on, but is not exclusively for, the low-income segment that may lack the knowledge of energy conservation, budget counseling and fuel assistance programs. Unlike other USPs administered by UGI, the CARES Program is geared toward the customer who has a temporary, immediate need, such as loss of income, loss of head of household, illness or any other temporary situation resulting in an inability to pay. CARES is intended to be a short-term assistance referral program to guide a customer through a difficult time and to help inform and educate them about the available assistance. The CARES Program also provides extensive LIHEAP outreach to help increase awareness of the program and encourage all eligible households to apply for grants. Specifically, all customers who provide UGI with a copy of their PFA order are handled by CARES representatives for specific program referrals and payment options.

2. Program Design

income, as calculated above, exceeds the customer's otherwise applicable average bill amount, the customer's average bill will be set as the customer's monthly CAP payment amount.

At any time during the program should a participant's monthly income change, the monthly CAP payment amount will also be reviewed and changed, where appropriate. It is the customer's obligation to notify the company or the CAP Administering Agency of the change in income. UGI reserves the right to require that the customer provide proof of the change in income. A recertification will be processed using the updated income and historical usage to determine the new monthly CAP payment amount.

Additionally, the participant's monthly CAP bill will be reevaluated quarterly, to ensure that the participant is actively on the most affordable billing option. For example, if the customer entered into CAP either at a 7%, 8%, or 9% income level, and upon a quarterly review, the customers average bill is deemed to be the most affordable at the time of the review, the customer's new CAP will be based on their average bill until the next review.

UGI's minimum monthly CAP payment is within the suggested range set forth in the Commission's Policy Statement on Customer Assistance Programs at 52 Pa. Code § 69.265(3)(i)(A)-(C). The CAP payment for gas heating accounts is set at $25, non-heating accounts at $15, and electric heating accounts at $30.

2. Household Income Documents

To determine CAP eligibility and the appropriate CAP monthly payment, proof of income at or below 150% of FPIG must be provided by the customer to the Company. However, for customers receiving LIHEAP, who have already been determined to have income under 150% of the FPIG by DHS, the Company will accept self-cetification of income level for the purpose of calculating the customer's monthly payment and no documentation of income is required for such customers. Acceptable income documents are:

- Recent paystubs or W-2 forms
- verified copy of rent receipts for rental income
- Benefit letter or copy of bank statement for;
  - Social security
  - Pension
  - Disability
  - SSI
- Verification Letter
  - ~~Child support and/or~~ alimony support
- Unemployment determination letter
- Notarized letter stating income
- Zero income form

Additional Notes:

- ~~Child support amount should be based off Court Order unless customer can provide proof that they are receiving a different amount (Example: Bank statement).~~
- Interest does not need to be counted as income.
- UGI does not include income earned from an occupant under the age of 18, nor does it include income received for the benefit of a minor, in its calculation of household income.

3. Use of LIHEAP Grants

LIHEAP grants received will be applied consistent with the Commonwealth of Pennsylvania's Low-Income Home Energy Assistance Program – Final State Plan ("Final State Plan"), and any subsequent amendments or changes thereto.

4. Late Fees & Security Deposits

While actively participating in the program, late payment charges will not be imposed on CAP customers. Security deposits are also not imposed on CAP customers.

I. PARTICIPANT OBLIGATIONS

In order to remain eligible for participation in CAP, a customer must agree to (in writing) and perform the following obligations:

- make the monthly CAP payments;
- apply for and direct to UGI the customer's LIHEAP Cash or Crisis grant;
- conserve energy and, if eligible, participate in LIURP and any other weatherization services offered through local and state weatherization agencies (unless residence was previously weatherized under these programs);
- provide access to the meter for an actual meter reading, if required;[13]
- participate in good faith and comply with all educational, assistance, social or governmental programs recommended by the Company or by the CBO;
- report immediately to the CBO any change in family size, or change in income
- comply with the recertification requirements; and
- apply for any assistance grant for which he/she may be eligible.

In order to assure fair treatment of all participants, however, UGI will administer the

[13] CAP Credit and Pre-Program Arrearage forgiveness may be held up if an actual meter reading is not available.

Energy to do more®

UGI Utilities, Inc. – Gas Division
UGI Utilities, Inc. – Electric Division

Universal Service & Energy Conservation Plan For the Five-Year Period January 1, 2020 – December 31, 2025

Docket No. M-2017-2598190

Filing Date: June 30, 2017
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Table of Contents

UGI 2020-2025 USECP

I. INTRODUCTION

UGI Utilities, Inc. ("UGI") hereby submits this revised Universal Service and Energy Conservation Plan ("USECP" or "Plan") for the five-year period January 1, 2020 through December 31, 2025 to the Pennsylvania Public Utility Commission ("PUC" or "Commission") for its review and approval in accordance with the Commission's *Universal Service and Energy Conservation Reporting Requirements* at 52 Pa. Code §§ 54.71 – 54.78 and §§ 62.1 – 62.8.[1] The USECP replaces and supersedes the UGI Companies' Universal Service and Energy Conservation Plan for the four-year period of January 1, 2014 through December 31, 2017 (the "2014-2017 USECP") previously approved by the Commission at Docket No. M-2013-2371824 by orders entered January 15, 2015, June 11, 2015 and September 3, 2015. The USECP pertains to the universal service programs of UGI's Electric Division ("UGI Electric") and Gas Division ("UGI Gas"). This revision incorporates the modifications required by the Commission's Order entered August 8, 2019 ("August 8th Order") and the Commission approval of the settlement in the UGI Gas base rate proceeding at Docket No. R-2018-3006814 (Order entered October 4, 2019)("2019 Rate Case Order").

This 2020-2025 USECP sets forth the rules, terms and conditions and funding levels under which UGI will administer its universal service and energy conservation programs and policies ("Universal Service Programs" or "USPs") to eligible customers for the period of January 1, 2020 through December 31, 2025. **Appendix A** of the Plan sets forth the committed funding levels and budgets for each of the UGI divisions during this time period. **Appendix B** of the Plan sets forth the projected needs assessment as required by the Commission's regulations at 52 Pa. Code § 62.4(b)(3).[2] **Appendices C & D** provide a list of third-party, community-based organizations ("CBOs") to be utilized by UGI to assist in administering the Universal Service Programs. **Appendix E** sets forth UGI's notification process to prompt customers to recertify for CAP. **Appendix F** provides the Zero Income form to be used for CAP. **Appendix G** provides the CAP Agency Audit Scorecard.

UGI Gas is a "public utility" and a "natural gas distribution company" ("NGDC") as defined under the Public Utility Code, 66 Pa.C.S. §§ 102 and 2202, and is subject to the regulatory jurisdiction of the Commission. UGI Gas provides natural gas distribution service and supplier of last resort ("SOLR") service. UGI Gas combined serves approximately 585,000 residential

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[1] By Order entered on October 3, 2019 at Docket No. M-2019-3012601 ("October 3rd Order"), the Pennsylvania Public Utility Commission granted temporary partial limited waivers of 52 Pa. Code §§ 54.74, 54.76 (a-b), 62.4, and 62.6 (a-b) to natural gas and electric distribution companies for the purpose of adhering to the 2020-2025 universal service and energy conservation plan and universal services impact evaluation filing schedule provided therein. The term of the UGI USECP is therefore 2020 through 2025.

[2] The needs assessment was calculated for the former UGI North and UGI South Rate Districts. The UGI Central Rate District was not required to conduct a projected needs assessment since it serves fewer than 100,000 residential accounts. See 52 Pa. Code § 62.7. Per the October 3rd Order these rate districts are no longer in existence. For the Company's next USECP, the needs assessment for UGI Gas will be calculated on a combined basis. UGI Electric is not required to conduct a projected needs assessment since it serves fewer than 60,000 residential accounts. See 52 Pa. Code § 54.77.

customers in 46 counties.

UGI Electric is a "public utility" and an "electric distribution company," as defined under the Public Utility Code, 66 Pa.C.S. §§ 102 and 2803, and is subject to the regulatory jurisdiction of the Commission. UGI Electric provides electric distribution, transmission and default supply services to customers located in its certificated service territory. UGI Electric furnishes electric distribution service to approximately 54,000 residential customers located in portions of two northeastern Pennsylvania counties (Luzerne and Wyoming counties).

On October 1, 2018 UGI Penn Natural Gas, Inc. ("PNG") and UGI Central Penn Gas, Inc. ("CPG") merged into UGI Utilities, Inc. Data prior to October 1, 2018 may reference the UGI Distribution Companies and individually, the former PNG, CPG, and UGI Utilities, Inc. – Gas Division corporate entities then in existence. References to "UGI Gas" pre-October 1, 2018 refer to the UGI Utilities, Inc. – Gas Division operations.

II. 2020-2025 USECP OVERVIEW

A. SUMMARY OF THE 2020-2025 USECP

1. USECP Programs

To assist low-income and payment-troubled customers located in their service territories, UGI has established the USECP in accordance with the Commission's regulations. UGI's Universal Service Programs include the following:

- Customer Assistance and Referral Evaluation Services ("CARES" or the "CARES Program");
- Hardship Fund or the "Operation Share Energy Fund";
- Customer Assistance Program ("CAP"); and
- Low Income Usage Reduction Program ("LIURP").

UGI also actively encourages payment-troubled, low-income customers to apply for grants from the Low-Income Home Energy Assistance Program ("LIHEAP").

2. Customers Served

In 2016, the UGI Distribution Companies assisted approximately 51,000 residential customers through their Universal Service Programs. The total number of participants by program for UGI Gas, UGI Electric, PNG and CPG in 2016 is set forth in Table 1: (CAP customer counts are as of 12/31/16).

Table 1. Universal Service Customers Served in 2016						
Number of Participants	**CAP**	**LIURP**	**CARES***		**Hardship Fund**	**Total**
			CARES referral	**LIHEAP recipients**		
UGI Gas	7,126	124	171	11,816	698	19,935
PNG	5,146	149	67	11,906	521	17,789
CPG	1,861	47	6	4,961	231	7,106
UGI Electric	2,322	16	16	2,734	167	5,255
Total	16,455	336	260	31,417	1,617	50,085

*CARES consists of number of CARES customer and # of LIHEAP (Cash and Crisis) recipients

A summary of the UGI Distribution Companies' program expenditures for the Universal Service Programs in 2016 is found below:

Table 2. 2016 Universal Service Program Expenditures					
Company	**CAP**	**LIURP**	**CARES**	**Hardship Fund**	**Total**
UGI Gas	$2,470,473	$853,543	$68,108	$6,980	$3,399,105
PNG	$2,137,094	$881,288	$36,617	$5,210	$3,060,209
CPG	$735,806	$294,362	$17,040	$2,310	$1,049,518
UGI Electric	$1,848,644	$76,960	$16,797	$1,670	$1,944,071
Total	$7,192,018	$2,106,153	$138,562	$16,170	$9,452,903

3. Administration

UGI has dedicated employees who are trained and committed to ensuring eligible customers are referred to all appropriate Universal Service Programs ("USP Staff") in order to provide the greatest benefits to customers. The USP staff is structured as follows:

- Director, Customer Service (1 full time): Responsible for overall strategy and development of universal service offerings.
- Senior Manager, Credit & Collections and Regulatory Compliance (1 full time): Responsible for the supervision of the group and all reporting requirements.
- Customer Outreach Senior Supervisor (1 full-time): Responsible for the day to day supervision of the group and all reporting requirements.

- Senior Customer Outreach Coordinator (1 full-time): Primarily responsible for training UGI staff and CBO caseworkers.

- Senior Customer Outreach Representative (2 full-time): Responsible for leadership support of Outreach team and the CBOs.

- Customer Outreach Representatives (6 full-time): Responsible for the day to day operations of LIURP, CAP, Operation Share Energy Fund, CARES and LIHEAP. Each maintains daily contact with the CBOs responsible for the administration of each program.

- LIHEAP Outreach Representatives (4 seasonal part-time): Responsible for the day to day operations of LIHEAP. Each maintains daily contact with CBOs responsible for the administration of LIHEAP.

UGI contracts with CBOs to assist the USP Staff in customer referrals and administration of the USPs. Together, the USP Staff and the CBOs have the capability to screen, enroll and refer customers for all available Universal Service Programs. The USP Staff incorporates all Universal Service Program referrals into existing processes (Cold Weather Interim Procedure ("CWIP"), collection, compliance and contract management). In addition to referrals to all Universal Service Program components, referrals are also made to LIHEAP and State Weatherization programs.

4. Communication

There are numerous means by which the USP Staff and its CBO partners provide residential customers with information on available programs and assist them in receiving assistance from CBOs. Information about the USPs is delivered to customers via regular bill inserts and through the USP Staff upon customer inquiry. UGI has a dedicated toll-free telephone number, 1-800-UGI-WARM that customers can call to get program information. UGI also maintains a page on its website that provides information on universal service programs and eligibility. https://www.ugi.com/customer-services/customerassistance/

As stated in more detail in the summary of plan changes, with this 2020-2025 USECP UGI is creating additional communication channels with their customers by permitting its customers to apply and/or recertify for CAP over the phone with provision of supportive documentation through mail, or additional means, as permitted by the CBOs.

B. SUMMARY OF CHANGES TO PLAN

As required by Section 62.4 of the Commission's regulations, 52 Pa. Code § 62.4, this section of the Plan describes the modifications and enhancements made to UGI's Commission-approved 2014-2017 USECP. Set forth below is a description of the changes made to the individual Universal Service Programs. Certain changes that touch on more than one program include: (1) UGI's establishment of a Universal Service Advisory Committee ("USAC") to convene at least twice per calendar year to consist of interested stakeholders, including but not limited to the active parties at this docket, CBOs, and the Commission's Bureau of Consumer Services; and (2) revisions to enrollment and budget projections.

1. The CARES Program

UGI has modified its protection from abuse ("PFA") handling procedures to further ensure the confidentiality of PFA information consistent with the settlement of the UGI Gas base rate proceeding, at Docket Number R-2015-2518438 (Opinion and Order entered October 14, 2016 at ordering paragraph 53). Consistent with the Settlement, any customer who provides UGI with a copy of their PFA order is handled solely by the smaller number of CARES representatives for USP program referrals and payment options.

2. Operation Share Energy Fund

UGI has made the following changes to the Operation Share Energy Fund:

- Permit the use of Hardship Funds for through Operation Share for reconnection fees for income-qualified UGI customers or applicants, regardless of the customer or applicant's prior or current enrollment in CAP.

- Clarification that only the fee payable to CBOs for Hardship Fund-related services is recoverable through the USP Rider.

3. CAP

The 2020-2025 Plan includes the following changes to CAP:

- Customers are permitted to apply and/or recertify for CAP over the phone, with provision of supportive documentation of income eligibility through mail. CBOs are permitted to offer additional means of providing supportive documentation. Those CBOs which offer additional means of communication are indicated in Appendix C of the Plan. In-person appointments with a CBO will remain available to those customers who choose to apply in person.

- To improve customer solicitation for CAP, starting in year 2 of the 2020-2025 USECP, the Companies will provide CAP CBOs with low-income indicated customer lists for direct CAP solicitation. Customers will have the ability to opt-out from provision of their customer information to third parties by a general opt-out option on the customer information system portal.

- The CAP welcome letter for enrolled customers will include the CBO contact information.

- Updated eligibility criteria as follows: (1) permitting customers who operate a business from their residential home to enroll in CAP so long as the business that is being operated from the residential home uses less than fifty percent of the anticipated gas usage served through a single meter; (2) prohibition of CAP for customers using utility service to heat a swimming pool; (3) elimination of the CAP eligibility restriction for customers with balances above $4,500 who have failed multiple payment arrangements; (4) specification of acceptable forms of identification; (5) clarification of "household income" definition; (6) clarification of terms "fraud" and "theft of service."

- Clarifications to the CAP application policy and reinstatement policy.
- Introduction of quarterly evaluations of CAP bills.
- Inclusion of Audit Checklist to evaluate CAP CBO performance as Appendix G.
- Specification of new reporting requirement.
- Provision of hypothetical to demonstrate CAP offset calculation.
- UGI Electric has increased its minimum CAP payment from $25 to $30 to comport with the Commission's Policy Statement on Customer Assistance Programs at 52 Pa. Code § 69.265(3)(i)(A)-(C).

4. LIURP

The 2020-2025 Plan includes the following changes to the LIURP program:

- Non heating LIURP customers may be provided an Energy Conservation Kit.
- Updated eligibility criteria as follows: (1) permitting customers who operate a business from their residential home to enroll in LIURP so long as the business that is being operated from the residential home uses less than fifty percent of the anticipated gas usage served through a single meter; (2) prohibition of LIURP for customers using utility service to heat a swimming pool; (3) clarification of "above-average" usage.
- Pursuant to the August 8th Order and the 2019 Rate Case Order, UGI Gas will expand the use of LIURP funds to address the repair or replacement of its residential customers' inoperable gas furnaces. UGI Gas will increase its per-job LIURP funding cap to $11,000 where furnace replacement is necessary. Additionally, UGI Gas will set aside $250,000 annually from its general LIURP budget for furnace repair and replacement projects. For the first two years of the USECP, any unused amounts will roll over to the next year's budget for furnace

repair and replacement projects. Should there continue to be amounts to roll over after two years, any remaining roll over amounts will roll over to UGI Gas's general LIURP budget. The August 8th Order approved UGI's petition for waiver of LURP regulation payback requirement at 52 Pa. Code § 58.11(a) and the LIURP high-use criteria at 52 Pa. Code § 58.10(a)(1). Paragraph 19 of the August 8th Order provided that these temporary waivers will expire in five years or with the Company's next USECP, whichever is earlier, unless an extension is expressly requested by the Company and granted by the Comission. (August 8th Order, p. 82) Subsequent to the August 8th Order, the Commission extended the term of this USECP to five (5) years. To maintain program continuity, the Company therefore requests that the Commission grant waiver of these regulations until the approval of UGI's next USECP.

C. <u>NEEDS ASSESSMENT</u>

As required by 52 Pa. Code § 62.4(b)(3), at the time of initial filing, UGI South and UGI North rate districts submitted a needs assessment in Appendix B of this Plan. The needs assessment is based on 2010 census data and 2015 UGI Gas records. Pursuant to 52 Pa. Code §§ 54.77 and 62.7, EDCs and NGDCs with less than 100,000 residential customers are not required to submit a needs assessment; therefore, UGI Electric and the former UGI Central rate district did not submit a needs assessment. Future USECPs will provide needs assessments on a combined basis for UGI Gas.

III. <u>THE CARES PROGRAM</u>

A. DESCRIPTION OF THE CARES PROGRAM

1. Goals and Objectives

The goal of the CARES Program is to provide personal assistance and referrals to payment-troubled customers and to help improve their delinquent bill payment problems. The CARES Program identifies special needs customers and guides them to the appropriate program or agency. CARES concentrates on, but is not exclusively for, the low-income segment that may lack the knowledge of energy conservation, budget counseling and fuel assistance programs. Unlike other USPs administered by UGI, the CARES Program is geared toward the customer who has a temporary, immediate need, such as loss of income, loss of head of household, illness or any other temporary situation resulting in an inability to pay. CARES is intended to be a short-term assistance referral program to guide a customer through a difficult time and to help inform and educate them about the available assistance. The CARES Program also provides extensive LIHEAP outreach to help increase awareness of the program and encourage all eligible households to apply for grants. Specifically, all customers who provide UGI with a copy of their PFA order are handled by CARES representatives for specific program referrals and payment options.

2. Program Design

The CARES Program was developed as an outreach and referral service to assist customers with special hardships. CARES is available to any residential customer who is confronted with a temporary hardship that could result in the loss of utility service. Assistance is obtained through UGI's programs and the established network of social agencies. CARES is designed to help a select group of customers with special circumstances, which may include, among other things, the need for help in paying their utility bill or assistance from a social agency. UGI offers information, guidance and referrals to obtain energy assistance and other social help programs from the Customer Outreach Department. Each CARES customer may receive an informational mailing. The mailing contains educational material on each of the assistance programs and any other referral information that may be helpful to the customer.

At appropriate times of the year, eligible CARES customers receive information on additional Customer Outreach programs, such as LIHEAP, LIURP, CAP, and the Operation Share Energy Fund.

B. FUNDING AND BUDGET

See Appendix A for the UGI's budgets for the CARES program.

C. ELIGIBILITY CRITERIA

Any residential customer with a delinquent balance or a negative ability-to-pay and special circumstance may be eligible for CARES. For example, recent unemployment, disability, loss of head of household, inability to understand their bill, temporary illness or need for senior citizen assistance, would render a customer eligible for CARES.

D. INTAKE / NETWORKING

Customer Outreach employees maintain contact with CBOs through referrals and educational services. Upon request, employees organize and/or conduct community meetings and workshops to educate customers in energy conservation and to increase public awareness of the various CARES Program services. Presentations are made throughout the service territory and brochures and literature are distributed to communicate the social services that are available to customers. Employees maintain communication with appropriate professional and local organizations to strengthen skills and remain current on local issues.

IV. THE OPERATION SHARE ENERGY FUND

A. PURPOSE & OBJECTIVES

A number of causes, foreseen and unforeseen, could potentially affect the ability of customers to pay their bills. UGI's hardship fund – Operation Share Energy Fund – has been formed for the purpose of providing assistance to residential customers faced with a hardship in paying their energy bill due to an unforeseen situation. To achieve its purpose, the Operation Share Energy Fund includes the following objectives:

- to provide customers, employees and the public an opportunity to contribute money to help their less fortunate neighbors who are unable to pay their energy bills due to unforeseen circumstances;
- to give financial assistance to current customers that have fixed or low incomes, are unemployed, disabled or faced with some catastrophic event or crisis situation;
- to provide additional funds and support to community organizations that are dedicated to this same purpose.

For the 2020-2025 USECP, UGI will be permitted to use hardship funds to pay for reconnection fees for customers or applicants who are income qualified for the program, regardless of the customer or applicant's prior or current enrollment in CAP.

B. FUNDING AND BUDGET

Operation Share funding will be used to make voucher payments directly to residential customers declared eligible by the designated administering agency, less amounts used for administrative expenses. For every two dollars the customers, employees or outside sources contribute to Operation Share, UGI will issue an additional one dollar in energy vouchers, up to the committed matching funds contribution. For example, UGI will contribute one dollar for every two dollars donated by a customer, employee or outside source, up to $10,000, its total matching funds contribution. No matching funds are made available to match public, tax-supported sources, such as LIHEAP, however. Employees of UGI are encouraged to make a donation directly to Operation Share. Additional fundraising events may be organized in each of UGI's service territories. It is intended that an appeal will be made at least twice during the year to all of UGI's customers, via a billing insert, to make a contribution to Operation Share. The insert describes Operation Share and requests support with a check for any amount.

See **Appendix A** for UGI's funding for the hardship fund.

C. ADMINISTRATION

The Operation Share program is administered by UGI's USP Staff using the Customer Outreach System ("COS"). The COS provides customer information, such as eligibility criteria, account balance, recent bills and payments. UGI contracts with CBOs that have the ability to process grants using web-based applications, which then use the account information from the COS to determine the amount of grant awarded to the customer. The COS also maintains the financial aspects of the program.

A specific role is established in the COS for the representative that has the final authority to approve or deny assistance for a customer. This designated person is responsible for the Operation funds assigned to a CBO. UGI's personnel will not participate in the determination of grants, other than to refer applicants to the CBO for consideration.[3]

Operation Share Energy Fund is designated as a public charity under section 501(c)(3) of the Internal Revenue Code. All donations from customers, employees, and outside sources are kept in a separate Operation Share bank account and passed directly to the participating agencies to permit them to make direct payments to energy vendors for those applicants who qualify.

D. ELIGIBILITY

The guidelines for grants from Operation Share allow for administrative flexibility in providing assistance. In order to assure fair treatment of all applicants, however, the following guidelines must be followed (unless UGI or the CBOs agree to waive or modify a guideline in extraordinary circumstances):

- the customer must have a residential account with UGI and the customer's premise is the customer's primary residence;
- the customer must have an active heating or non-heating utility account;
- the customer must not have received an Operation Share grant in the last 12 months;
- the customer must have an outstanding balance on their utility bill;
- the maximum income of the customer's household must be at or below the current federal poverty income guidelines ("FPIG") of 200%;
- the customer must provide adequate information to demonstrate inability to pay energy bills;[4]
- customers for Operation Share with delinquent balances must first contact the Credit Department to discuss their options; and
- an active participant in the CAP is not eligible for Operation Share assistance.

Residential accounts with the following indicators are not eligible for this program:

- health care facilities;
- landlord/tenant (account is in the landlord's name);
- ratepayer/occupant (the ratepayer does not reside at the property);
- foreign load (one meter supplies more than one unit);

[3] There are some occasions where personnel will approve Operation Share on a customer's behalf, for example, in the instance of a legislative request to supplement LIHEAP grants.

[4] Necessary information includes evidence of income of all members of the household. In addition, the applicant will authorize the CBO (verbally or written) to obtain account history information from their energy vendor. There is no requirement that each household member must verify household expenses as part of the Operation Share application process.

- theft of service; and
- Landlord if Shut-off ("LIFSO") agreement (account is in the owner's name).

In order to assure fair treatment of all customers, the following amounts represent the maximum grant to be awarded per eligible customer in each of UGI's divisions and rate districts.

Table 3. Maximum Operation Share Grant	
Division	**Maximum Amount**
UGI Gas	$400
UGI Electric	$400

Exceptions to the maximum grant amount may be approved for special circumstance customers.

E. PAYMENT OF GRANTS

The designated CBO is granted a maximum amount against which vouchers can be written. So long as the CBO's maximum amount is not exceeded, a voucher may be written and will be honored by UGI for the payment of the applicant's bill.

All cash funds must be retained by the CBO in its Operation Share account and payments from this account shall only be made to UGI. Under no circumstances will any payments be made directly to a customer.

V. CUSTOMER ASSISTANCE PROGRAM

A. INTRODUCTION

CAP provides all eligible low-income, payment-troubled residential customers that reside in the rate districts of UGI a more affordable way to pay their natural gas or electric bill. Each month, CAP participants are billed an equal CAP payment amount based on the participant's gross income or average bill,[5] depending on which option provides the most affordable monthly CAP payment.

In this 2020-2025 USECP, UGI will continue the practice instituted in the previous 2014-2017 USECP to place no limit on CAP enrollment or set a maximum CAP credit per customer.

B. INTAKE/NETWORKING/EDUCATION

Customer Outreach employees maintain contact with CBOs through referrals and educational services. Upon request, employees organize and/or conduct community meetings and

[5] A customer's average bill will be determined based upon twelve-months of historical usage for the residence or, if usage data is not available for the residence, the customer's average bill will be set using the average bill for all residential customers.

workshops to educate customers of the benefits of CAP. Presentations are made throughout the service territory and brochures and literature are distributed to communicate the social services that are available to customers. Employees maintain communication with appropriate professional and local organizations to strengthen skills and remain current on local issues. UGI will work with its USAC to explore opportunities to provide consistent consumer education to CAP customers during their participation in CAP.

C. FUNDING AND BUDGET

See Appendix A for a more detailed description of CAP funding.

D. ADMINISTERING AGENCIES

CAP is administered by a variety of CBOs, listed in Appendix C of this Plan (the "CAP CBOs") that are overseen by UGI's Customer Outreach Senior Supervisor.

With the help of the COS, the CAP CBOs are responsible for taking the following steps to enroll customers in the CAP[6]:

- verify the application is complete and consent has been obtained;
- properly complete the CAP enrollment;[7]
- verify eligibility, proof of identification, proof of income and family size;
- assist applicant to properly complete LIHEAP and other grant applications;
- fully explain the program benefits and responsibilities to the customer;
- discuss the payment amount, based on guidelines provided by UGI; and
- inform applicants in writing of missing information along with steps the applicant can follow to provide that information.
- confirm customer's acceptance in the program.
- inform applicants in writing if CAP application is denied along with steps the applicant can follow to contest denial.

The CAP CBOs will provide customer education in the areas of:

- usage reduction education consistent with that outlined in LIURP below;
- low cost/no cost energy conservation tips;
- basic household budget counseling; and
- related items specific to the individual applicant's needs, including providing an energy

[6] UGI's USP Staff also enroll eligible customers into the CAP program.
[7] The CAP enrollment process will include application completion via telephone or mail when an in person visit is not required or feasible.

education session for customers who historically have an above average usage.[8]

The CAP CBOs are responsible for: (1) referring participants to any other assistance, social, or governmental programs that may provide help for any other present needs; (2) monitoring each account monthly based on UGI's prompted tasks on the COS, such as past due phone calls and recertification; and (3) providing energy education sessions to above average usage customers (i.e. customers exceeding the CAP usage criteria in Table 4).

Finally, while the CAP Administering Agencies will be responsible for processing the annual recertification of all requirements, UGI itself will process appeals for reconsideration from participants removed from CAP within 30 days.

Two changes in this 2020-2025 USECP, previously mentioned, are (1) the allowance of alternate means of communication for CAP enrollment and recertification; and (2) the expanded ability of CAP CBOs to directly solicit low-income indicated customers of the UGI Companies.

Alternative Means of Communication for CAP Enrollment and Recertification

UGI will allow customers and applicants for service to apply and/or recertify for CAP over the phone, with provision of supportive documentation through mail or other means (including but not limited to fax, email, or text messaging) that are reasonably available to the Company's CBO serving that portion of UGI's service territory. Once the CBO has verified that all of the documentation is received and accurate, the Company will send a Welcome Letter to the applicant, which will: (1) confirm that the applicant has been approved for CAP ; (2) provide the applicable CBO contact information; and (3) explain that at any time the customer may unenroll from CAP. In-person appointments with a CBO will remain available to those individuals who choose to apply in person. The available means of communication for each CBO is indicated on **Appendix C**.

Direct Solicitation

In year 2 of this USECP, UGI will provide CBOs with low-income customer lists for direct CAP solicitation.[9] To maintain customer privacy and respect customer preference, customers will have an option to opt-out from provision of their information to third-parties by a general opt-out option on the Customer Information System ("CIS") and through information on bill inserts.

E. MONITORING

UGI will provide routine information and metrics to the CAP CBO pertaining to the performance of the administration of the program. In addition, UGI will make routine visits to the agencies and will also conduct annual training updates for CAP caseworkers. Further, UGI will audit agency performance by reviewing: enrollments, re-certifications, and completed tasks. The

[8] The UGI Companies will monitor CAP customer usage and implement controls to avoid excessive CAP customer usage.
[9] UGI will implement the direct solicitation of CAP customers by CBOs in year 2 of the USECP to ensure that any programming required for this programmatic change is completed prior.

audit will include confirmation that the appropriate paperwork is signed and when required, income verification and customer identification were obtained. The COS will maintain specific agency statistics such as: number of program participants; percentage of CAP customers that are past due; and an active list of customers that require re-certification. UGI's audit checklist is outlined in **Appendix G**.

F. EVALUATION

As required by the Commission's regulations, 52 Pa. Code § 62.6, both a program process evaluation and impact evaluation were performed in 2012 by an independent, third party evaluator (APPRISE), which provided a report of findings addressing the following areas:

- program design;
- administrative costs;
- program costs;
- payment behavior;
- consumption habits; and
- energy assistance participation.

UGI considered the recommendations of the APPRISE report in reviewing and preparing this 2020-2025 USECP. By Order entered on October 3, 2019 at Docket No. M-2019-3012601, the Commission granted temporary partial limited waivers of 52 Pa. Code §§ 54.74, 54.76 (a-b), 62.4, and 62.6 (a-b) to natural gas and electric distribution companies for the purposes of adhering to the 2020-2025 universal service and energy conservation plan and universal services impact evaluation filing schedule provided therein. UGI's next USECP evaluation report will be filed with the Commision by April 1, 2024 as provided in the October 3rd Order.

G. CUSTOMER ELIGIBILITY REQUIREMENTS

To be eligible for CAP, customers may be referred by UGI or CAP CBOs. To be eligible, a customer must: (1) complete the CAP application and have gross household income verified at 150 percent of poverty or less;[10] (2) be a residential heating or non-heating customer with active energy service from UGI; and (3) if a previous participant, a review will be completed to assure the reason for the prior default has been cured or the customer has been out of the program for a minimum of 12 months for a voluntary removal.

An applicant's Social Security Number (SSN) is requested in the CAP application as a form of customer identification, but is not required for enrollment into the program. UGI will accept Individual Tax Identification Numbers ("ITIN") in lieu of the applicant's SSN. For those applicants who do not provide either a SSN or ITIN, UGI will waive this requirement provided that the customer provides two other acceptable forms of identification. Acceptable forms are:

[10] A customer with no income will be eligible to participate in CAP and be responsible to make the minimum monthly CAP payment.

1. One government issued photo identification such as:
   - Driver's License
   - Passport
   - Military ID card
   - ID cards issued by Federal State or Local Government or;
   - Any valid foreign government ID

2. Two alternative forms of identification if a government issued photo identification is not available, such as:
   - College student ID card
   - Social security card
   - Voter registration card
   - Birth Certificate
   - U.S. Citizen ID card/ Permanent Resident Card
   - Native American Tribal Card
   - ITIN (individual Taxpayer Identification Number)

All forms of identification must be valid and not expired.

Residential accounts with the following indicators are ineligible for CAP or will be removed from CAP:

- health care facilities;
- landlord/tenant (account is in the landlord's name);
- ratepayer/occupant (the ratepayer does not reside at the property);
- foreign load (one meter supplies more than one unit);
- theft of service;
- LIFSO agreement (account is in the owner's name);
- choice customers;
- utility service used to operate a swimming pool;
- a residential property where more than fifty percent of the anticipated usage served through a single meter is used to operate a business.

UGI further reserves the right to deny enrollment if the customer is deemed to lack good faith, honesty or fair dealing while working with the CAP CBO or one of UGI during the application process or if the customer fails to engage in good faith efforts to conserve energy. Demonstration of lack of good faith honesty and fair dealing may be evidenced by fraud or theft of service. The Company defines "fraud" as the intentional misrepresentation of CAP eligibility criteria. "Theft of Service" occurs when a person obtains utility service by deception, tampering with Company facilities, or other means designed to avoid payment for utility service provided by the Company. The two most common examples of theft of service are: (1) a customer's physical bypass of a meter so that all energy usage is not recorded; and (2) the magnetic tampering of a meter to impede the registration of usage. However, this list is not conclusive and other instances of theft may arise that results in a customer's disqualification from CAP.

Upon request, subject to the recertification process, a CAP participant must provide evidence of continued program eligibility, which he/she may do so via the communication means indicated on **Appendix C**.

If a CAP participant changes residences, the following conditions will apply and be communicated to the customer: (1) as long as all eligibility requirements and other terms and conditions continue to be met, the participant may remain eligible to participate in CAP; and (2) so long as the participant remains enrolled in the program, no late payment charges will be imposed.

An applicant determined ineligible would receive written notification specifying the reason(s) for ineligibility. If the applicant is not satisfied with the determination of eligibility, the Company will use utility company dispute procedures in accordance with Chapter 56.151 and 56.152. The applicant may also appeal the denial of eligibility to the Bureau of Consumer Services in accordance with 52 Pa. Code §§ 56.162-56.166, relating to informal complaint procedures and may pursue a formal complaint against the Company. Notice of right to appeal will be provided with the written notification of ineligibility.

H. MONTHLY CAP PAYMENT AMOUNT

1. Determination of Monthly CAP Payment Amount

The amount to be paid by a CAP customer each month will be based on the lower of the percentage of the customer's monthly income, as described below, or the customer's otherwise applicable average monthly bill.[11] To determine the customer's monthly CAP payment amount based on the percentage of the customer's income, the customer's monthly income is compared to the FPIG, and the payment amount is set based on the following guidelines:

	Percent of Poverty	Monthly CAP Payment
Income Level 1:	0[12] - 50%	7% of Participant's Monthly Income
Income level 2:	51 - 100%	8% of Participant's Monthly Income
Income level 3:	101 - 150%	9% of Participant's Monthly Income

If a customer's monthly CAP payment amount as a percentage of the customer's monthly

[11] Exceptions to the payment schedule and grant application practice will be made based on individual needs.
[12] A customer with no income will be responsible to make the minimum monthly CAP payment.

income, as calculated above, exceeds the customer's otherwise applicable average bill amount, the customer's average bill will be set as the customer's monthly CAP payment amount.

At any time during the program should a participant's monthly income change, the monthly CAP payment amount will also be reviewed and changed, where appropriate. It is the customer's obligation to notify the company or the CAP Administering Agency of the change in income. UGI reserves the right to require that the customer provide proof of the change in income. A recertification will be processed using the updated income and historical usage to determine the new monthly CAP payment amount.

Additionally, the participant's monthly CAP bill will be reevaluated quarterly, to ensure that the participant is actively on the most affordable billing option. For example, if the customer entered into CAP either at a 7%, 8%, or 9% income level, and upon a quarterly review, the customers average bill is deemed to be the most affordable at the time of the review, the customer's new CAP will be based on their average bill until the next review.

UGI's minimum monthly CAP payment is within the suggested range set forth in the Commission's Policy Statement on Customer Assistance Programs at 52 Pa. Code § 69.265(3)(i)(A)-(C). The CAP payment for gas heating accounts is set at $25, non-heating accounts at $15, and electric heating accounts at $30.

2. Household Income Documents

To determine CAP eligibility and the appropriate CAP monthly payment, proof of income at or below 150% of FPIG must be provided by the customer to the Company. However, for customers receiving LIHEAP, who have already been determined to have income under 150% of the FPIG by DHS, the Company will accept self-cetification of income level for the purpose of calculating the customer's monthly payment and no documentation of income is required for such customers. Acceptable income documents are:

- Recent paystubs or W-2 forms
- verified copy of rent receipts for rental income
- Benefit letter or copy of bank statement for;
    - Social security
    - Pension
    - Disability
    - SSI
- Verification Letter
    - alimony support
- Unemployment determination letter
- Notarized letter stating income
- Zero income form

Additional Notes:

- Interest does not need to be counted as income.
- UGI does not include income earned from an occupant under the age of 18, nor does it include income received for the benefit of a minor, in its calculation of household income.

3. Use of LIHEAP Grants

LIHEAP grants received will be applied consistent with the Commonwealth of Pennsylvania's Low-Income Home Energy Assistance Program – Final State Plan ("Final State Plan"), and any subsequent amendments or changes thereto.

4. Late Fees & Security Deposits

While actively participating in the program, late payment charges will not be imposed on CAP customers. Security deposits are also not imposed on CAP customers.

I. PARTICIPANT OBLIGATIONS

In order to remain eligible for participation in CAP, a customer must agree to (in writing) and perform the following obligations:

- make the monthly CAP payments;
- apply for and direct to UGI the customer's LIHEAP Cash or Crisis grant;
- conserve energy and, if eligible, participate in LIURP and any other weatherization services offered through local and state weatherization agencies (unless residence was previously weatherized under these programs);
- provide access to the meter for an actual meter reading, if required;[13]
- participate in good faith and comply with all educational, assistance, social or governmental programs recommended by the Company or by the CBO;
- report immediately to the CBO any change in family size, or change in income
- comply with the recertification requirements; and
- apply for any assistance grant for which he/she may be eligible.

In order to assure fair treatment of all participants, however, UGI will administer the aforementioned obligations with sufficient flexibility to provide the assistance intended by the program. Therefore, UGI or CAP CBOs may agree to waive or modify one or more of the

[13] CAP Credit and Pre-Program Arrearage forgiveness may be held up if an actual meter reading is not available.

participant obligations in extraordinary circumstances.

J. PRE-PROGRAM ARREARAGE FORGIVENESS

UGI forgives a CAP customer's pre-program arrearage balance on a one thirty-sixth (1/36th) basis upon receipt of each timely and in-full CAP monthly payment. This practice provides immediate incentive for a CAP customer to continue the positive payment behavior. UGI also provides no less than a $10.00 per month pre-program arrearage forgiveness. UGI applies arrearage forgiveness for each timely and in-full monthly payment, regardless of arrears, and retroactively for any months missed once those months are paid. For example, if a CAP customer is delinquent for three months of payments, and makes catch-up payments for two of those three months, the customer will receive forgiveness for those two months.

To be eligible for pre-program arrearage forgiveness, participants must maintain all program requirements in each month since enrolling in the program.

K. APPLICATION OF CAP CREDITS

Pursuant the Commission’s regulations, at 52 Pa. Code § 62.2, and UGI’s effective tariffs, a CAP credit is set as the difference between the CAP customer’s actual usage bill calculated at the standard residential rate and the CAP monthly bill. UGI applies CAP credits on a monthly basis with each full CAP payment received. Any CAP credits associated with missed CAP payments will be applied once the customer brings their payments up to date.

UGI eliminated its per-customer maximum CAP credit in its 2014-2017 USECP. UGI’s 2020-2025 USECP will likewise not have a per-person CAP credit maximum.

UGI institutes the following CAP control features to encourage energy conservation:

High Annual Usage at Enrollment: UGI uses the following thresholds to determine when a customer is considered to be a high usage customer. These thresholds were determined by analyzing the current population of customers and their usage information and determining a 95% confidence level.

Table 4. High Usage Criteria

Division	High Usage
UGI Gas	2,356 ccf
UGI Electric	34,465 kwh

Any customer that applies for CAP, and any existing CAP customer with usage above these assigned thresholds, will:

1. Participate in an interview with the CAP caseworker. The CAP caseworker will review

data specific to the customer's residence to determine potential reasons for the customer's high usage.
2. The CAP caseworker will then conduct an energy education session.
3. If applicable, referrals will be made for the LIURP program.
4. If enrolled, high usage will continue to be monitored for additional outreach and referrals.

This high-usage evaluation will take place annually for existing CAP customers.

Removal from CAP

1. A CAP customer may be removed from CAP for refusing to participate in the LIURP program.
2. A customer may be removed for failure to comply with these high usage controls.[14]

L. RECERTIFICATION POLICY

1. CAP Recertification Requirements for LIHEAP and Non-LIHEAP Participants

Participants must provide evidence of continued program eligibility. The recertification process is a mandatory requirement in order to ensure proper participation and continued program eligibility.

UGI has a triennial recertification requirement for known LIHEAP participants. CAP customers who are not known LIHEAP participants are required to recertify for CAP annually. A customer will not be deemed ineligible for CAP on the basis of failure to participate in LIHEAP. Non-LIHEAP CAP customers who recertify annually for CAP will remain enrolled in CAP. To recertify, participants must provide:

- For LIHEAP Participants - When the LIHEAP income guidelines are the same as CAP; LIHEAP participants who have received a LIHEAP Cash or Crisis grant within the last 12 months will only be required to provide income documentation every three years to UGI.[15]

- For Non-LIHEAP Participants - Income documentation must be provided annually to verify that the participant's household income is at or below the current 150% of the FPIG.

Should the participant fail or refuse to recertify within two billing cycles of being notified

[14] Exceptions may be granted where the factors giving rise to the customer's increased consumption are beyond the customer's reasonable control.
[15] Historically the income criteria for CAP has matched that for LIHEAP. Should the LIHEAP and CAP income requirements differ, UGI will notify the LIHEAP-participating CAP customer of the responsibility to recertify on an annual basis.

to do so, UGI may remove the customer from CAP. UGI believes this practice encourages those participants who continue to have household incomes at or below 150% to complete the recertification process and, therefore, maintain affordable energy bills. The customer is responsible to reenroll in the program.

2. Recertification Reminder Schedule

The Companies actively remind CAP participants of their obligation to recertify income eligibility as per the following schedule:[16]

- A recertification notice letter is mailed a month prior to the anniversary date (recertification due date);
- A contact from the CBO is made 15 days prior to the anniversary date;
- A reminder letter is mailed from the Company on the anniversary or on the recertification due date; and
- A contact from the CBO is made 1 month past the anniversary date.

3. Use of Zero Income Statements for CAP Enrollment and Recertification

UGI customers who report zero household income at the time of CAP enrollment and recertification are required to complete a "Zero Income Form," as set forth in Appendix F. The Zero Income Form need not be notarized. The Zero Income Form must be filled out by the individual who holds the account with UGI. The following information is required: (1) customer name; (2) date of application; (3) account number; (4) service address; (5) a list of adult household members with zero income; and (6) an explanation of how household expenses were met for food and shelter during the applicable period. The Zero Income Form must be signed by both the account holder and a CAP CBO representative. As stated on the form, by signing the Zero Income Form, the customer provides consent to UGI to verify income with government agencies. UGI CBOs have reported that use of the form does not hinder participation in the UGI universal service programs and therefore UGI will continue to use the Zero income form without modification.

As outlined in the participant obligations customers are to immediately report a change in household size or income. Specifically, for a customer who reports zero income, UGI will require the customer update their income (if they have not already done so) six months following the report of zero income.

4. Impact of Recertification

Appropriate changes in the percentage of income and/or average bill payment will be made upon completion of the recertification process. If income or average bill payment at the time of recertification dictates a change in the monthly payment, the new amount will be used for future monthly payments. Future bills issued upon completion of recertification will reflect an

[16] *See* Appendix E for a schematic of the Companies' recertification process.

appropriate CAP bill amount but past CAP bills issued are the customer's responsibility to pay. During the recertification process, if a participant is deemed ineligible for continued participation in CAP, the customer will be notified that they are no longer eligible to participate and the reason(s) why they are no longer eligible for CAP.

M. REASONS FOR REMOVAL FROM CAP

- Failure to make CAP payments that results in termination and the customer has not cured his/her payments within 109 days of termination.
- failure to comply with any customer obligation set forth in the program;
- failure to comply with the obligation of good faith, honesty and fair dealing while working with the CAP CBO or UGI;
- household income increases to greater than 150% poverty;
- failure to comply with established high usage controls;[17]
- refusal to participate in LIURP;
- any reason for which the customer's service may be terminated under Chapter 56 or Chapter 14;
- failure/refusal to recertify in CAP;
- bankruptcy - at the time of the filing of bankruptcy all receivable amounts which may include frozen pre-program arrearage will fall under the jurisdiction of the bankruptcy court and will no longer be eligible for CAP benefits; and
- legal action - should UGI have reason to take legal action against a participant that encompasses any receivable owed it, all receivable amounts which may include pre-program arrearages will fall under the jurisdiction of the applicable court and will no longer be eligible for CAP benefits. Participants removed from the CAP will receive a written statement indicating the reason(s) for the dismissal. Customers defaulting and dropped from the CAP will be referred to the Company's Credit and Collection Department for further action, if necessary.

Any CAP participant may voluntarily request to be removed from the program. However, if a CAP participant requests to be removed from CAP for the reason that their seasonal usage bills total less than the monthly CAP amount ("seasonal short-term benefit"), the customer will be removed from the program and will forfeit all program benefits. The customer will then be required to remain out of CAP for a period of twelve months before they can re-apply for the program, provided exceptions will be granted on a case-by-case basis based on demonstrated hardship. The customer will be mailed a letter to confirm his request to be voluntarily removed

[17] Exceptions may be granted where the factors giving rise to the customer's increased consumption are beyond the customer's reasonable control.

from CAP. UGI will accept the request for removal via phone with a UGI representative.

UGI removes customers when service is voluntarily discontinued by the customer and the CAP participant is no longer a customer. All unpaid bills and unforgiven dollars are due upon the removal from CAP as this is considered a broken payment arrangement.

UGI also reserves the right to remove any CAP customer if the program is deemed non-beneficial without having to receive the customer's consent.

N. CAP NON-PAYMENT DEFAULT AND CREDIT AND COLLECTION POLICIES

Customers who miss a CAP payment are provided two payment notifications prior to the Company initiating its termination procedures. After the customer's first missed payment, assuming the payment has not been made, the CAP CBO sends a notification to the customer at 15 days and 25 days after the missed payment. The 15-day notification may be a letter or telephone call. The 25-day notification is a mailed letter. Both the 15 and 25 day notifications advise the customer that their CAP payment is overdue.

Upon the customer's second missed CAP payment, UGI moves forward with the appropriate notifications and shut-off procedure and will send a termination notice stating the past-due amount. The customer will be required to pay the amount set forth in the termination notice, prior to the scheduled termination date to avoid shut-off. If the customer fails to pay per the terms of the termination notice, service is shut off.

When the service is shut off for non-payment, the terminated customer has up to 109 days to pay the full catch-up CAP amount, including any CAP bills that may have come due during the shut-off process, plus reconnection fees. Upon receipt of the full catch-up amount and the reconnection fee, the customer will be returned to CAP. If the terminated customer does not pay the full catch-up amount within 109 days, the customer will be removed from CAP and the customer will be responsible to make full payment of any outstanding balance and reconnections fees prior to the reconnection of service. Upon full payment and service restoration, the customer may then re-apply to enroll in CAP. One additional exception to the reinstatement policy would be when the customer's actual balance is less than the CAP balance.

UGI Utilities, Inc. Operation Share hardship funds will be permitted to be used for reconnection fees for all eligible UGI customers.

O. REINSTATEMENT POLICY

Customers requesting reinstatement must comply with and agree to all applicable program eligibility requirements and customer obligations. As a condition of reinstatement, a customer must:

- provide adequate assurance that the reason(s) for the prior default and resulting program dismissal have been removed or corrected; and

- make up all missed CAP payments or full balance when appropriate before reinstatement.

As a condition of reinstatement, a customer may also be required, depending upon individual circumstances, to make an up-front payment. Upfront payments are most common for a customer that is looking to restore service and remain on CAP. A reconnection charge can be required as an upfront payment. Another scenario where an upfront payment is required is when it is a prerequisite for the customer's receipt of additional grants or program services. For example, if a customer owes $500 in missed CAP payments, a CBO may require the customer to pay $300 which permits the CBO to approve $200 in Federal Emergency Management Agency ("FEMA") funds. The Companies never charge a CAP participant a security deposit for reconnection of service.

As stated above, UGI Utilities, Inc. Operation Share hardship funds will be permitted to be used for reconnection fees for all eligible UGI customers.

If a customer voluntarily removes themselves from CAP for seasonal short-term benefit, the customer will not be eligible again until after a one-year waiting period. The customer, however, would be able to have their CAP reinstated before the year if they, at the time of their request, can satisfy the CAP amount covering both the missed CAP payments while on CAP, and the month(s) they spent out of the program (i.e. CAP catch-up amount).

P. CAP UNIVERSAL SERVICE REQUIREMENTS REPORTING

As required by the August 8th Order, by April 1st of each year, UGI Utilities, Inc. shall file and serve a report at these dockets detailing the following information by utility, FPIG level, and account type for the preceding calendar:

- CAP Participation Rate;
- Average Annual CAP Credits;
- Number of CAP accounts that exceeds the previous maximum CAP Credit limit;
- Total dollars above previous maximum CAP Credit limit;
- Average of CAP credits above previous maximum CAP Credits;
- Gross Write-Offs in Dollars by Residential Customers and Confirmed Low-Income Customers
- The difference in pre-program and current energy usage (+/-) of CAP customers who exceeded energy usage threwwsholds but received energy conservation assistance from a CAP caseworker (stated as an average yearly percentage)

VI. LIURP

A. INTRODUCTION

UGI's LIURP consists of a Weatherization Program and a Rehabilitation Program.

B. FUNDING AND BUDGET

See Appendix A for a more detailed discussion of the program budgets.

C. LIURP ENROLLMENT LEVELS

The table shows the number of jobs completed per Company and the associated spending for the period of 2014 through 2016.

Table 5. Completed LIURP Jobs for 2014 - 2016		
Company	**Number of jobs**	**Cost**
UGI Gas	318	$2,048,978
PNG	399	$2,566,887
CPG	194	$1,131,508
UGI Electric	71	$287,895

D. LIURP REPORTING REQUIREMENTS

The Companies report all data required by the LIURP codebook.

E. LIURP WEATHERIZATION PROGRAM

The LIURP Weatherization Program is offered to reduce the energy consumption of low-income customers through the installation of energy conservation measures and energy conservation education. By reducing the energy consumption of these customers, the intent of LIURP is to reduce customer arrearage, collection and termination costs. The program places top priority on the health and safety of all LIURP participants.

Program services are provided free of charge to the customer. Upon verification of program eligibility by the LIURP agency, each LIURP heating customer will receive an on-site energy survey/audit. Energy saving measures for gas customers and electric space heat customers may include, but are not limited to, the following: insulation, furnace repair/replacement, water heater repair/replacement, furnace efficiency modification, windows and baseboard caulking, door and window weather stripping, door sweeps and thresholds, replacement of broken window panes, storm windows, attic ventilation, electrical outlet and switch plate gaskets on outside walls, water conservation measures, energy education, infiltration measures and incidental repairs (necessary to the effective performance of weatherization materials). Low cost energy saving measures for electric non-heating customers may include but are not limited to: refrigerator replacement, high efficiency lighting, window air conditioner replacement and other measures necessary to the effective performance of weatherization materials within the job limit costs. Eligible electric non heating customers may receive an in home or telephonic energy education sessions. For the 2020-2025 USECP, UGI will begin to provide UGI Electric weatherization participants with an Energy Conservation Kit containing items they may install to reduce electric consumption.

Energy saving measures installed will be those Commission-approved measures in the LIURP codebook. Job inspections are completed by a third party agency.

Additionally, UGI Gas will, in this 2020-2025 USECP, expand the use of LIURP Weatherization Program funds to address the repair or replacement of its residential customers' inoperable gas furnaces. UGI Gas will increase its per-job LIURP funding cap to $11,000 where furnace replacement is necessary. Additionally, UGI Gas will set aside $250,000 annually from its general LIURP budget for furnace repair and replacement projects. For the first two years of the USECP, any unused amounts will roll over to the next year's budget for furnace repair and replacement projects. Should there continue to be amounts to roll over after two years, any remaining roll over mounts will roll over to UGI Gas's general LIURP budget. In its August 8, Order, the Commission has approved UGI Gas's petition to waive the LIURP regulation payback requirement at 52 Pa. Code § 58.11(a) and the the high-use criteria at 52 Pa. Code § 58.10(a)(1) for customers needing furnace repair or replacement.

1. Weatherization Program Administration

Refer to **Appendix D** for the CBOs currently contracted for the provision of energy survey and measure installation. In addition, UGI engages a third-party to independently verify that home weatherization was completed in accordance with LIURP standards.

2. Weatherization Program Eligibility

To be eligible for the LIURP Weatherization Program, the customer must be able to demonstrate the following:[18]

- the customer is an active residential gas heating customer or residential electric customer;[19]
- the customer's gross household income is at or below the current 150% of the FPIG;[20]
- the customer's annual consumption is above average usage; Above average usage is defined as a customer who exceeded the average residential threshold by 25% for electric customers (baseload and heat) and 30% for natural gas customers. The threshold will be reviewed annually to consider significant changes in usage patterns.

[18] Exceptions may be granted.
[19] UGI Gas will waive the requirement that the customer be an active gas heating customer for the purpose of furnace repair or replacement spending.
[20] However, up to 20% of LIURP participants may have a household income at 151-200% of the FPIG, on a first-come, first-serve basis.

Table 6. Minimum Usage Criteria	
Division	**High Usage**
UGI Gas	950 ccf
UGI Electric	12,788 kwh

- the customer has had continuous service for twelve months;
- the customer's premises are suitable for weatherization services;[21] and
- the customer's premise is the customer's primary residence.[22]
- The premise has not received LIURP weatherization services for the past seven (7) years.

Residential accounts with the following indicators are not eligible for the LIURP Weatherization Program:

- health care facilities;
- landlord/tenant (account is in the landlord's name);
- ratepayer/occupant (the ratepayer does not reside at the property);
- foreign load (one meter supplies more than one unit);
- LIFSO agreement (account is in the owner's name);
- utility service used to operate a swimming pool
- a residential property where more than fifty percent of the anticipated gas usage served through a single meter is used to operate the business.

3. Weatherization Program Outreach and Intake Efforts

UGI is in constant contact with weatherization CBOs, local government, weatherization providers and any other appropriate agencies for input and advice on the most efficient and effective methods to provide LIURP weatherization services without duplication or exclusion. Through the use of local CBOs, such as LIURP providers found in **Appendix D**, integration of federal, state and local funds for LIURP weatherization participants are more easily accomplished. UGI will inform each LIURP weatherization participant of any and all appropriate services.

4. Weatherization Program Identification & Referral of Low-Income Customers

With the use of COS for the administration of LIURP, UGI reviews its customer records

[21] Program measures follow applicable payback periods; therefore, a customer's residence that has been previously weatherized may not be eligible for LIURP until the applicable payback period has expired.
[22] The program is available to both homeowners and renters. Renters can qualify with written permission from landlords.

to identify high usage, high arrearage, low income customers. In addition, UGI accepts referrals from CBOs, community groups and customer inquiries. LIURP referrals may also come from UGI's Energy Efficiency and Conservation Plan program management.

5. Weatherization Program Inter-Utility Coordination

UGI maintains contact with appropriate gas and electric utilities within their service territory to initiate inter-utility coordination with both NGDCs and EDCs when applicable.[23] UGI and the other utilities coordinate comprehensive program services to better serve LIURP weatherization customers. In many cases, UGI and the corresponding utility employ the same LIURP measure installer. Therefore, inter-utility coordination may be accomplished without the need for written contract or inter-utility billing. As previously stated in the CAP section, UGI will form a USAC which will hold two annual meetings. UGI will include the electric utilities that overlap its gas service territory to these meetings to continue to discuss the coordination of the provision of LIURP services, and particularly, to improve identification of customers with inoperable natural gas furnaces who may be using electricity for space heating so as to improve the provision of LIURP services for those customers.

F. REHABILITATION PROGRAM

Through the Rehabilitation Program, UGI funds the installation of energy efficient measures at the time of construction or rehabilitation of low-income residential housing. These measures include the installation of ENERGY STAR rated high efficiency natural gas furnaces, hot water heaters, upgraded installation, and energy efficient windows.

The Rehabilitation Program achieves usage reduction by: (1) allowing identified low-income and special needs customers to benefit from a variety of energy efficient measures which will avoid future high usage, and (2) maximizing the LIURP dollars spent on installed weatherization measures. Specifically, this program treats low income housing at the construction/rehabilitation phase in order to maximize material and labor dollars. The expectation is that these homes could eventually receive LIURP services. Therefore, through this program, these customers receive service at the construction/rehabilitation phase to assist in covering the costs of the project(s) and to avoid future high usage and arrearage problems. By implementing energy efficiency measures at the rehabilitation or construction phase, the overall cost of the measures can be more economical than implementing them after the construction is complete. UGI periodically joins forces with rehabilitation projects within its service area to assure energy efficiency in low income housing.

1. Rehabilitation Program Eligibility

Each Rehabilitation Program project must have the following criteria to qualify for LIURP

[23] UGI restates its commitment to coordinating with EDCs in overlapping service territories who may be providing similar services pursuant to Act 129.

services and/or funds:

- the customer is an active residential gas heating customer or residential electric customer;
- the customer's premise is the customer's primary residence.[24]
- the customer's gross household income is at or below the current 200% of the FPIG; and
- existing gas heat or electric heating customer;[25] and
- coordination with a CBO(s).

Possible CBOs that would become involved in this project include:

- Neighborhood Housing Services;
- Habitat for Humanity;
- Housing Authorities; and
- Community Development Offices.

Residential accounts with the following indicators are not eligible for the LIURP Rehabilitation Program:

- health care facilities;
- landlord/tenant (account is in the landlord's name);
- ratepayer/occupant (the ratepayer does not reside at the property);
- foreign load (one meter supplies more than one unit);
  LIFSO agreement (account is in the owner's name);
- utility service used to operate a swimming pool.
- a residential property where more than fifty percent of the anticipated gas usage served through a single meter is used to operate the business.

All LIURP required information will be collected for each dwelling.

UGI will reserve up to 10% of its total current year LIURP budget for Rehabilitation Project Funding. If the entire budgeted amount is not expended, the remainder will be returned to traditional LIURP services funding.

As with the 2014-2017 USECP, UGI: (1) will limit the use of LIURP funding under this program to residential rate housing units and, in the case of rental housing units, only where the tenant has payment responsibilities for the utility service; (2) may direct funds to HOME developments, the Low Income Housing Tax Credit ("LIHTC") program and to non-profit agencies; and (3) will track customer participation levels and energy savings on a prospective basis.

[24] The program is available to both homeowners and renters. Renters can qualify with written permission from landlords.
[25] Customers of UGI-Electric with electric heat are eligible to participate in the LIURP Rehabilitation Program.

UGI 2020-2025 USECP

In the 2020-2025 UGI will continue to track and report the program results and details separately.

UGI 2020-2025 USECP

APPENDIX A

FUNDING COMMITMENTS FOR EACH UNIVERSAL SERVICE PROGRAM

I. UGI PROJECTED PARTICIPATION AND BUDGET PER PROGRAM

Projected participation and budgets for USECP programs are set forth below. For LIURP and Operation Share, participation and budget figures are provided for the geographic footprints of the UGI Gas Division's former three rate districts in accordance with settlement paragraph 38 of the 2019 UGI Gas Rate Case Settlement.

A. CAP

1. UGI Gas

UGI Gas's projected participation levels and budget for CAP is shown below:

Table A-1. UGI Gas CAP Annual Participation Levels & Budget for 2020-2025		
Year	**Projected Participation Levels**	**Projected Budget**
2020	20,123	8,954,230
2021	21,129	9,401,880
2022	22,185	9,872,006
2023	23,294	10,365,606
2024	24,458	10,883,887
2025	25,680	11,428,081

2. UGI Electric

UGI Electric's projected participation levels and budget for CAP is shown below:

Table A-2. UGI Electric Annual CAP Participation Levels & Budget for 2020 - 2025		
Year	**Projected Participation Levels**	**Projected Budget**
2020	2,885	$2,725,275
2021	3,029	$2,861,300
2022	3,180	$3,005,050
2023	3339	$3,155,303
2024	3506	$3,313,068
2025	3681	$3,478,721

B. LIURP

The projected LIURP participation levels and budgets for the geographic footprint of the former UGI Gas rate districts, and the UGI Electric service territory are set forth in table A-3.

UGI 2020-2025 USECP

APPENDIX A

Table A-3. Annual LIURP Participation Levels & Budget 2020 - 2025[26]		
Geographic Area	**Projected Participation Levels**	**Projected Budget**
South	202	$1,605,900
North	194	$1,333,450
Central	85	$695,000
UGI Electric	66	$274,750

C. OPERATION SHARE HARDSHIP FUND

Table A-4. UGI Operation Share Company Annual Funding Level for 2020 – 2025[27]		
Geographic Area	**Energy Funds Amount**	**Matching Funds**
South	$38,500	$38,500
North	$22,000	$22,000
Central	$12,000	$12,000
Electric	$10,000	$10,000
SubTotal	$82,500	$82,500
Total	**$165,000**	

Table A-5. UGI Operation Share Annual Costs by Geographic Area for 2020 – 2025[28]						
Geographic Area	**Projected Participation Levels**	**Initial Contribution (voucher)**	**Matching Funds (voucher)**	**Projected CASH donations**	**Total Donations**	**Projected Administrative Budget[29]**
South	385	$38,500	$38,500	$77,000	$154,000	$5,775
North	185	$22,000	$22,000	$30,000	$74,000	$2,775
Central	120	$12,000	$12,000	$24,000	$48,000	$1,800
Electric	98	$10,000	$10,000	$19,000	$39,000	$1,470

UGI proposes to allocate available funds to administering agencies, based on the 2010 Census Data, as updated in 2015, and the Commission's estimate of the number of residents under 150% of the FPIG, as follows:

[26] The Settlement of the UGI Gas 2019 Rate Case increased the aggregate UGI Gas LIURP budget by $500,000, which was distributed proportionally between the different geographic areas of the service territory.
[27] This does not include Customer donations.
[28] Cash donations are donations provided by utility customers.
[29] The increase is due to per-grant CBO fee increase from $10 to $15.

UGI 2020-2025 USECP

APPENDIX A

Table A-6. UGI Allocations By Geographic Area

Former Rate District	Agency	Inter-Area Funding Allocation
UGI South	Allentown Salvation Army	15%
	Bethlehem Salvation Army	5%
	Easton Salvation Army	10%
	Harrisburg Salvation Army	21%
	Commission on Economic Opportunity	3%
	Lancaster Community Action Program	19%
	Lebanon Christian Ministries	5%
	Reading Salvation Army	22%
North	AGAPE	7%
	Commission on Economic Opportunity	35%
	Scranton Salvation Army	38%
	S.T.E.P., Inc.	11%
	TREHAB, Inc.	2%
	Union-Snyder Community Action Agency	7%
Central	Central PA Community Action	8%
	Central Susquehanna Opportunities	12%
	East Stroudsburg Salvation Army	6%
	Hamburg Salvation Army	20%
	Commission on Economic Opportunity	8%
	Northern Tier Community Action Corp	14%
	Schuylkill County Community Action	5%
	S.T.E.P., Inc.	2%
	TREHAB, Inc.	24%
	Union-Snyder Community Action Agency	1%

Each administering agency must spend their share of donations in order to maintain the allocation of funds; otherwise, UGI reserves the right to reallocate the funds to another administering agency. Furthermore, if and when there is a change to the existing administering agencies, such as, for example, an addition or removal of an agency, UGI will revise the amounts allocated to the administering agencies accordingly.

UGI 2020-2025 USECP

APPENDIX A

D. CARES

UGI Gas's projected participation levels and budget for LIHEAP and CARES Outreach are shown below:

Table A-7. UGI Gas CARES Participation Levels & Budget 2020-2025	
Projected Participation Levels	**Projected Budget**
185	$115,000

UGI Electric's projected participation levels and budget for CARES is shown below:

Table A-8. UGI Electric CARES Participation Levels & Budget 2020-2025	
Projected Participation Levels	**Projected Budget**
20	$20,000

II. UGI RIDER USP

In accordance with the Company's Gas Tariff[30] and Electric Tariff[31] available at https://www.ugi.com/tariffs/, UGI is permitted to recover costs for the USECP under its USP Riders with an annual reconciliation for costs and recoveries. The Rider USP rate shall be calculated to recover costs for the following programs: LIURP; CAP; Hardship Funds; and any other replacement or Commission-mandated Universal Service Program or low income program that is implemented during the period that the Rider is in effect.

[30] UGI Gas – Pa. P.U.C. No. 7.
[31] UGI Electric Pa. P.U.C. No. 6.

UGI 2020-2025 USECP

APPENDIX B

PROJECTED NEEDS ASSESSMENT

Per 52 Pa. Code § 62.4(b)(3), NGDCs with more than 100,000 residential accounts are required to provide a projected needs assessment for each Universal Service Program component and provide an explanation of how each program component responds to one or more identified needs. Per 52 Pa. Code § 62.7, UGI did not conduct a projected needs assessment for the former Central Rate District as it served fewer than 100,000 residential accounts. Likewise, UGI Electric is not required to conduct a projected needs assessment since it serves fewer than 60,000 residential accounts, as per 52 Pa. Code § 54.77.

The needs assessment for the former UGI South and UGI North Rate Districts, based on 2015 Census Data, included the number of estimated and identified low-income customers, the number of estimated and identified payment-troubled, low-income customers, the number of customers still needing LIURP services and the cost to serve them and the enrollment size of CAP to serve all eligible customers.

Table B-1.

	UGI SOUTH	**UGI NORTH**
1. Number of Identified Low-Income Customers	34,269	23,061
2. Estimate of Number of Low-Income Customers	91,478	49,410
3. Number of Identified Payment-Troubled, Low-Income Customers[32]	8,353	4,663
4. Number of Customers In Need of LIURP Services[33]	5,251	4,756
5. Cost of Serving the Number of Customers In Need of LIURP Services	$36,142,633	$28,131,740
6. Enrollment Size of CAP to Serve all Eligible Customers	34,269	23,061

In future USECPs the Company will provide a consolidated needs assessment for the Gas Division that will incorporate all former rate districts.

[32] 52 Pa. Code § 62.4 requires the inclusion of estimated low-income payment-troubled customers in a NGDC's needs assessment. Due to the methodology employed by the UGI Companies, this figure is equal to the identified payment-troubled low-income customers set forth in line 3 and is not repeated to avoid redundancy.

[33] This figure accounts for the following eligibility criteria: (1) identified low-income; (2) 12 months of consecutive service; (3) meeting LIURP usage criteria; (4) premises not having received LIURP weatherization services within the past seven (7) years. The UGI Companies may grant exceptions where warranted on a case-by-case basis to customers who do not meet this eligibility criteria and will report exceptions annually to the Commission.

UGI 2020-2025 USECP

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UGI 2020-2025 USECP

APPENDIX C

CAP COMMUNITY BASED ORGANIZATIONS

Table C-1.

CBO	**Communication Methods**	**Geographic Region**
Commission on Economic Opportunity	Mail, Email, & Fax	All Gas and Electric
Easton Area Neighborhood Center	Mail, Email, & Fax	South
Lancaster CAP	Mail, Email, & Fax	South
Lebanon County Christian Ministries	Mail, Email, & Fax	South
Neighborhood Housing Services of Greater Berks, Inc.	Mail, Email, & Fax	South
The Salvation Army	Mail, Email, & Fax	South
AGAPE	Mail, Email, & Fax	North
Scranton Lackawanna Human Development Agency-SLHDA	Mail, Email, & Fax	North
Social Service Assistance Program - S.T.E.P., Inc.	Mail, Email, & Fax	North, Central
TREHAB, Inc.	Mail, Email, & Fax	North, Central
Union-Snyder Community Action Agency	Mail, Email, & Fax	North, Central
Central PA Community Action Program, Inc.	Mail, Email, & Fax	Central
Central Susquehanna Opportunities, Inc.	Mail, Email, & Fax	Central
Northern Tier Community Action Agency/SLHDA	Mail, Email, & Fax	Central
Schuylkill County Community Action	Mail, Email, & Fax	Central

UGI 2020-2025 USECP

APPENDIX D

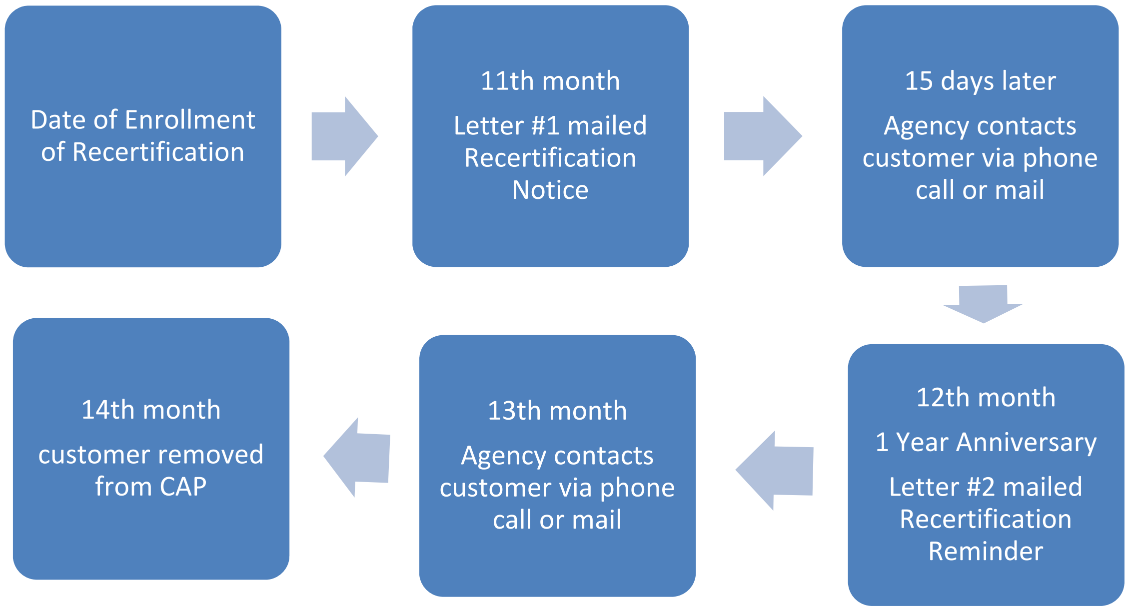
LIURP AGENCIES

Table D-1		
CBO	**City**	**Geographic Area**
Berks Community Action Program	Reading	South, Central
Commission on Economic Opportunity	Kingston	South, North, Electric
Community Action Committee of the Lehigh Valley and Central PA	Bethlehem, Clearfield	South, Central
South Central Community Action Program	Gettysburg	South
Scranton- Lackawanna Human Development Agency	Scranton	North, Electric
SOLAIR, Inc.	Ralston	Electric
SEDA-COG	Canton, Lewisburg	North, Central
Carbon County Action Committee for Human Services	Lehighton	Central

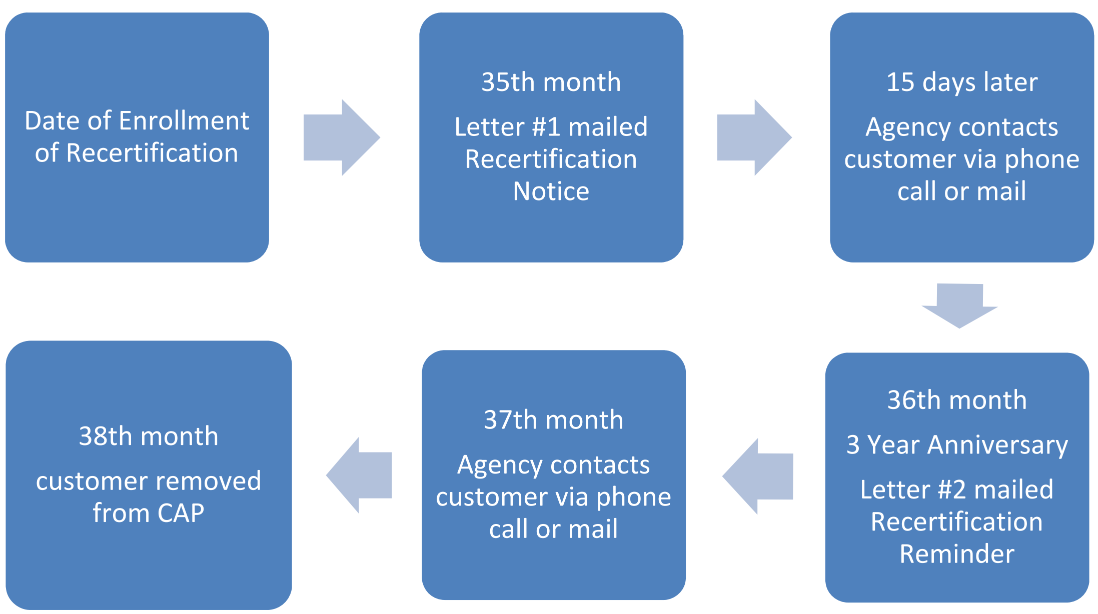
UGI 2020-2025 USECP

APPENDIX E

Notification Schedule for CAP Recertification Process-NO LIHEAP (Annual Certification)



Notification Schedule for CAP Recertification Process-LIHEAP (Triennial Certification)



UGI 2020-2025 USECP

APPENDIX F

UGI
Universal Service Customer Assistance Program

Customer Name: ____

Date of Application: ____

Account #: ____

Service Address: ____

Verification of Zero Income Claim

To be completed and signed by the UGI customer who had no income during the 30 day, 90 day or 1 year period before the date of this CAP application.

Verification:

I, (print) ______________________________, state that I have had no income from any source. I understand that participation in CAP can be denied for making false statements, and do affirm that all claims made here are true and correct to the best of my knowledge, information and belief. Any change in household income or occupants will be immediately reported to my assigned CAP agency. I give UGI and/or my assigned CAP agency permission to verify income with government agencies.

List all adult household members with zero income:

1. ____
2. ____
3. ____

During the above period, how were household expenses met for food and shelter?

____

____

____

Customer Signature: ________________________________

Agency Representative: ________________________________

UGI 2020-2022 USECP

APPENDIX G

Energy to do more®

CAP- Agency Audit Scorecard

Agency____

Account Number_______________________________ Customer Name ______________________

Does the account being audited contain the following:

YES	NO	N/A	
☐	☐		APPLICATION
☐	☐		CONSENT AND RELEASE FORM
☐	☐		TRUTH OF STATEMENT
☐	☐	☐	PROOF OF INCOME
☐	☐	☐	PROOF OF IDENTIFICATION
☐	☐		DOCUMENTATION ON THE ACCOUNT LOG
☐	☐		DOES THE INFORMATION ENTERED IN COS MATCH THE APPLICATION?
☐	☐		DOES THE PROOF OF INCOME INFORMATION MATCH THE APPLICATION?
☐	☐		COMPLIES WITH RECORD RETENTION POLICY

The following may not be applicable for all accounts:

YES	NO	N/A	
☐	☐	☐	RECERTIFICATION FORM COMPLETED
☐	☐	☐	HIGH USAGE QUESTIONNAIRE
☐	☐	☐	ZERO INCOME FORM

Auditor Comments____

____

Auditors Initials___________ Date____________

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Universal Service and Energy Conservation Plan for the Five-Year Period January 1, 2020 – December 31, 2025	:	Docket No. M-2017-2598190 et al

VERIFICATION

I, Daniel V. Adamo, Director of Customer Service for UGI Utilities, Inc. hereby state that the facts above set forth are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: December 5, 2019

Daniel V. Adamo

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Universal Service and Energy Conservation Plan for the Five-Year Period January 1, 2020 – December 31, 2025	:	Docket No. M-2017-2598190 et al

CERTIFICATE OF SERVICE

I hereby certify that I have, this 6th day of December, 2019, served a true and correct copy of the foregoing document in the manner and upon the persons listed below in accordance with requirements of 52 Pa. Code § 1.54 (relating to service by a participant):

VIA ELECTRONIC AND FIRST CLASS MAIL:

Elizabeth R. Marx, Esquire
Pennsylvania Utility Law Project
118 Locust St.
Harrisburg, PA 17101
pulp@palegalaid.net
CAUSE-PA

Christy M. Appleby
Office of Consumer Advocate
555 Walnut St
Forum Place, 5th Floor
Harrisburg, PA 17101-1921
cappleby@paoca.org

Joseph L. Vullo, Esquire
Burke Vullo Reilly Roberts
1460 Wyoming Avenue
Forty Fort, PA 18704
JLVullo@aol.com
CEO

Danielle Jouenne

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-14

Request:

Please indicate for each year for the past three years, whether:

a. UGI Gas exhausted its LIURP budget;

b. If such budget was not exhausted, indicate the number of dollars not spent;

c. UGI's three gas divisions exhausted its LIURP budget;

d. If such budget was not exhausted, indicate the number of dollars not spent;

e. If UGI's LIURP budget was exhausted, indicate the number of LIURP applicants that did not receive LIURP services despite having been found to be LIURP eligible;

Response:

a. UGI Gas only exhausted its LIURP budget in 2018 for the North District.

b.

	2018	2019	2020	2021
South	$530,531	$753,712	$1,497,368	$354,796
North	$(32,955)	$137,547	$884,099	$490,140
Central	$- 0	$- 0	$355,399	$165,453

c. - d. See the response to CAUSE-PA-I-14-b.

e. Not Applicable.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 8, 2022

CAUSE-PA-I-15

Request:

What is the average annual income of UGI's currently identified confirmed low income customers?

Response:

The average annual income of UGI's currently identified low income customers is $12,084.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-16

Request:

What is the average annual income of UGI’s currently enrolled CAP customers?

Response:

As of 2/27/2022, the average annual income for UGI's CAP customers is $14,525.94.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-17

Request:

From 2019 to date, disaggregated by month, how many residential customers does/did UGI serve? Please explain how UGI arrived at this figure, and include citations and/or copies of any and all workpapers used to perform the calculation.

Response:

Please see Attachment CAUSE-PA-I-17 for total residential customers by month for FY19-FY22 to date. Customer counts are generated from the UGI Gas billing system and is reflective of active customers at month end.

Prepared by or under the supervision of: Sherry A. Epler

UGI Utilities, Inc.-Gas Division
Total Residential Customers by Month
FY19 - FY22 to date

Month	Counts
Oct-18	577,839
Nov-18	582,652
Dec-18	585,605
Jan-19	587,697
Feb-19	588,654
Mar-19	588,826
Apr-19	586,199
May-19	583,945
Jun-19	583,675
Jul-19	583,515
Aug-19	583,231
Sep-19	584,702
Oct-19	586,571
Nov-19	591,539
Dec-19	593,709
Jan-20	595,269
Feb-20	595,921
Mar-20	596,502
Apr-20	596,145
May-20	595,836
Jun-20	596,121
Jul-20	596,128
Aug-20	596,583
Sep-20	597,957
Oct-20	599,814
Nov-20	602,010
Dec-20	603,531
Jan-21	604,527
Feb-21	605,108
Mar-21	605,476
Apr-21	605,021
May-21	602,970
Jun-21	600,658
Jul-21	600,045
Aug-21	599,837
Sep-21	600,640
Oct-21	603,495
Nov-21	608,000
Dec-21	610,197
Jan-22	611,761

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE PA Set I (1 thru 26)
Delivered on March 4, 2022

CAUSE-PA-I-26

Request:

Regarding Operation Share, for each month from January 2019 to current, please provide:

a. The total amount of available funds as of the last day of the month,

b. The total amount of grant money awarded in that month disaggregated by Federal Poverty Level (FPL) income tier (0-50%, 51-100%, 101-150%, 151-200%, 201-250%),

c. The average grant amount disaggregated by FPL income tier (0-50%, 51-100%, V 101-150%, 151-200%, 201-250%),

Response:

a. Please see Attachment CAUSE-PA-I-26-a.

b. Please see Attachment CAUSE-PA-I-26-b.

c. Please see response to CAUSE-PA-I-26-b.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division Operation Share Available Funds (End of Month)							
Jan 2019	$548,923	Jan 2020	$440,167	Jan 2021	$2,789,959	Jan 2022	$1,916,100
Feb 2019	$548,632	Feb 2020	$520,396	Feb 2021	$2,531,740		
Mar 2019	$523,186	Mar 2020	$509,047	Mar 2021	$2,270,693		
Apr 2019	$518,536	Apr 2020	$491,974	Apr 2021	$1,980,002		
May 2019	$512,567	May 2020	$478,084	May 2021	$1,802,600		
Jun 2019	$437,102	Jun 2020	$487,056	Jun 2021	$1,624,929		
Jul 2019	$414,098	Jul 2020	$722,892	Jul 2021	$1,502,434		
Aug 2019	$395,585	Aug 2020	$718,171	Aug 2021	$1,461,223		
Sep 2019	$518,803	Sep 2020	$1,676,311	Sep 2021	$1,462,323		
Oct 2019	$500,100	Oct 2020	$2,730,704	Oct 2021	$1,980,316		
Nov 2019	$502,689	Nov 2020	$3,089,807	Nov 2021	$1,912,860		
Dec 2019	$460,754	Dec 2020	$3,025,182	Dec 2021	$1,914,578		

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set II (1 thru 16)
Delivered on March 21, 2022

CAUSE-PA-II-10

Request:

For each year in the past 5 years, disaggregated by year, what would the residential customer bill have been for a household at average usage levels if WNA had been in effect under the following parameters?

a. No dead band
b. 1% dead band
c. 3% dead band
d. 5% dead band

Response:

UGI Gas does not have the ability to recompute individual historic bills for determination of specific WNA billing impacts. However, please see Attachment CAUSE-PA-II-10 for a proxy of what the calculated annual WNA impact would have been to a residential bill over the past five years using an estimated average usage across the various deadbands. In addition, please see Attachment CAUSE-PA-II-9 for a five-year history of a monthly residential bill using the same estimated average usage.

Prepared by or under the supervision of: John D. Taylor

CAUSE-PA St. 1 - Appendix B
Cited Discovery Responses

Attachment CAUSE-PA-II-10
J. D. Taylor
Page 1 of 1

UGI Utilities, Inc. - Gas Division
WNA Scenario Analysis (Fiscal Years 2017 - 2021)
Estimated Annual Impact to R/RT Customer at Current Rates
charge (credit) to customer

	No Deadband	1% Deadband	3% Deadband	5% Deadband
Fiscal 2017	$ 39.05	$ 37.39	$ 34.11	$ 30.84
Fiscal 2018	$ 7.81	$ 8.65	$ 10.28	$ 10.68
Fiscal 2019	$ 6.17	$ 6.58	$ 5.34	$ 3.69
Fiscal 2020	$ 35.35	$ 32.87	$ 28.77	$ 25.48
Fiscal 2021	$ 29.59	$ 26.71	$ 22.60	$ 19.32

Assumptions:

Modeling based on estimated annual usage per UGI Gas Exhibit E for R and RT customers of 844 ccf using currently effective rates.

For modeling the estimated annual usage was allocated by month using the following percentages:

OCT	5.8%	JAN	20.1%	APR	7.0%	JUL	1.4%
NOV	11.5%	FEB	16.3%	MAY	3.1%	AUG	1.5%
DEC	15.8%	MAR	13.4%	JUN	1.8%	SEP	2.3%

Monthly baseloads were calculated using the daily usage calculated during the period of June-September multiplied by the number of days in each month

Composite historical and normal HDD data used as found on SDR-RR-11(a). Assumes all customers' calculations are based on the composite HDD information. If approved, actual WNA calculations would be specific to each customer's delivery region.

The above amount represents an approximation of WNA charges/credits only and does not reflect any other additional riders that may be applied such as DSIC or STAS

The underlying model assumes that all customers are billed and weather is measured based on calendar month which will differ from actual billing and weather periods that would be used if implemented. See Rider K in UGI Gas Exhibit F for proposed tariff language.

CAUSE-PA St. 1 - Appendix B - p.73

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set II (1 thru 16)
Delivered on March 21, 2022

CAUSE-PA-II-16

Request:

According to the most recent data available, what is the average residential bill savings per LIURP job? Please provide copies of any studies, reports, or other documents relied upon for this calculation.

Response:

2019 Savings:*

Company	Total Pre CCF/KWH	Total Post CCF/KWH	Total % Saved
UGI Gas	182,876	145,068	21%
UGI PNG	243,003	194,682	20%
UGI CPG	65,474	49,348	25%
UGI Electric	913,013	832,384	9%

*2020 Savings data is not available until 4/28/22.

The Company's Customer Outreach system tracks the pre-weatherization and post weatherization 12 month usage. This data is then normalized and reported in the Low Income Usage Reduction Program (LIURP) Report due by April 30th, each year.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set III (1 thru 25)
Delivered on March 28, 2022

CAUSE-PA-III-4

Request:

Once a customer falls behind on their bill, at what point does the overdue balance stop accruing interest?

Response:

The interest stops accruing when the final bill is produced post termination.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set IV (1 thru 14)
Delivered on April 14, 2022

CAUSE-PA-IV-1

Request:

How does UGI define the term “Confirmed Low Income Customer”? Please explain how UGI calculates its count and include citation and/or copies of all workpapers.

Response:

The Company reports Confirmed Low Income Customer Counts each year in the Universal Service Reporting Requirements. Per the Data Dictionary and Clarifications Offered by BCS, Utilities are reminded to include all Fuel Fund recipients (LIHEAP CASH and CRISIS grants) in the "confirmed low income" category.

A non-fuel fund recipient will also be defined as a "Confirmed Low Income Customer" if they are a CAP participant, a LIURP Participant (at or below 150%) an Operation Share participant (at or below 150%) or, if for purposes of receiving a security deposit waiver, the customer provided income information to their local Community Based Organization (CBO).

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set IV (1 thru 14)
Delivered on April 14, 2022

CAUSE-PA-IV-2

Request:

How does UGI define the term “Estimated Low Income Customer”? Please explain how UGI calculates its count and include citation and/or copies of all workpapers used to perform the estimation.

Response:

The Pennsylvania Public Utility Commission provides the estimated low income customer counts annually for the utilities to complete the Universal Service Reporting Requirement annual filing due 4/1.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set IV (1 thru 14)
Delivered on April 14, 2022

CAUSE-PA IV-3

Request:

What is UGI's currently projected annual LIURP budget for 2022-2025?

Response:

2022 - 2025 LIURP Budget by Geographic Territory:

SOUTH - $1,641,100
NORTH - $1,363,050
CENTRAL - $710,200

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set IV (1 thru 14)
Delivered on April 14, 2022

CAUSE-PA IV-8

Request:

As of April 1, 2022, how many UGI customers were at risk of termination, disaggregated by:

a. Residential customers

b. Confirmed low income customers

c. CAP customers

Response:

The Company defined "at risk of termination" as accounts that meet the arrearage threshold set in the system that would trigger a 10-day notice being mailed.

a. 30,251

b. 5,840

c. 4,680

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to CAUSE-PA Set IV (1 thru 14)
Delivered on April 14, 2022

CAUSE-PA IV-14

Request:

For 2017, 2018, 2019, and thus far in 2020 (Jan.-Apr.), disaggregated by month, please provide:

a. the number of residential customers in debt
b. the number of confirmed low-income customers in debt
c. the percentage of residential customers in debt
d. the percentage of confirmed low-income customers in debt
e. the dollars in debt for residential customers
f. the dollars in debt for confirmed low-income customers
g. the percent of dollars owed that are on a payment arrangement for residential customers
h. the percent of dollars owed that are on a payment arrangement for confirmed low-income customers
i. the average arrearage for residential customers
j. the average arrearage for confirmed low-income customer

Response:

Per discussion with CAUSE-PA, the corrected dates are 2019, 2020, 2021 and 2022 year to date.

Please see Attachment CAUSE-PA-IV-14.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division

Month/Year	a. # Res. Customers in Debt	b. # of Low Inc. Customers in Debt	c. % of Res. Customers in Debt	d. % of Low Inc. Customers in Debt	e. $ in Debt (All Res)	f. $ in Debt Low-Income	g. % Dollars owed on P/A (All Res)	h. % Dollars owed on P/A (Low-Inc)	i. Average Arrears (All Res)	j. Average Arrears (Low-Inc)
JAN 2019	82,125	26,929	13.75%	37.66%	$ 29,468,707	$ 18,161,923	61.09%	94.54%	$ 359	$ 674
FEB 2019	82,208	26,504	13.77%	36.04%	$ 31,371,513	$ 18,775,551	58.92%	94.15%	$ 382	$ 708
MAR 2019	82,919	27,296	13.84%	35.92%	$ 34,609,839	$ 20,278,414	57.24%	93.37%	$ 417	$ 743
APR 2019	79,375	26,526	13.24%	34.87%	$ 31,565,615	$ 18,317,348	56.63%	92.56%	$ 398	$ 691
MAY 2019	79,161	27,530	13.23%	35.99%	$ 31,464,021	$ 19,163,650	60.38%	93.58%	$ 397	$ 696
JUN 2019	78,574	28,327	13.16%	37.21%	$ 29,845,946	$ 19,385,893	65.35%	94.91%	$ 380	$ 684
JUL 2019	71,907	28,288	12.06%	37.24%	$ 27,276,890	$ 19,143,743	71.07%	95.95%	$ 379	$ 677
AUG 2019	67,404	28,116	11.29%	37.02%	$ 25,712,799	$ 19,097,876	75.42%	96.43%	$ 381	$ 679
SEP 2019	58,636	26,056	9.91%	35.07%	$ 22,649,372	$ 17,243,595	77.47%	96.90%	$ 386	$ 662
OCT 2019	56,831	24,164	9.55%	33.25%	$ 19,719,256	$ 14,542,381	73.99%	95.57%	$ 347	$ 602
NOV 2019	56,218	23,861	9.40%	33.23%	$ 19,591,281	$ 14,433,970	73.43%	94.97%	$ 348	$ 605
DEC 2019	56,462	23,855	9.42%	32.45%	$ 20,280,335	$ 14,984,239	73.81%	95.05%	$ 359	$ 628
JAN 2020	62,177	24,738	10.34%	33.24%	$ 23,648,615	$ 16,588,878	69.93%	95.23%	$ 380	$ 671
FEB 2020	65,956	25,160	10.95%	32.52%	$ 26,644,829	$ 17,703,189	66.07%	94.96%	$ 404	$ 704
MAR 2020	65,278	25,808	10.85%	32.75%	$ 28,207,406	$ 18,610,190	65.46%	94.55%	$ 432	$ 721
APR 2020	64,157	25,789	10.66%	33.36%	$ 30,174,506	$ 19,625,554	65.06%	94.83%	$ 470	$ 761
MAY 2020	64,938	26,032	10.79%	32.75%	$ 31,972,480	$ 20,724,589	64.66%	94.48%	$ 492	$ 796
JUN 2020	62,617	25,942	10.38%	32.68%	$ 31,839,742	$ 20,848,692	65.67%	94.96%	$ 508	$ 804
JUL 2020	63,328	26,355	10.49%	33.44%	$ 32,307,351	$ 21,357,336	66.47%	95.18%	$ 510	$ 810
AUG 2020	63,371	26,671	10.50%	34.07%	$ 32,160,808	$ 21,661,563	67.93%	95.59%	$ 508	$ 812
SEP 2020	62,541	26,343	10.32%	33.88%	$ 31,848,406	$ 21,699,498	68.87%	95.78%	$ 509	$ 824
OCT 2020	65,457	26,534	10.78%	34.82%	$ 32,131,575	$ 22,045,854	69.54%	96.05%	$ 491	$ 831
NOV 2020	61,914	25,668	10.17%	34.03%	$ 31,760,220	$ 21,979,207	70.27%	96.31%	$ 513	$ 856
DEC 2020	65,360	25,427	10.71%	33.72%	$ 32,411,887	$ 22,121,921	68.62%	95.79%	$ 496	$ 870
JAN 2021	65,804	24,646	10.78%	32.32%	$ 33,898,419	$ 22,593,871	66.36%	95.13%	$ 515	$ 917
FEB 2021	68,453	24,582	11.20%	31.86%	$ 36,662,211	$ 23,254,769	62.97%	94.50%	$ 536	$ 946
MAR 2021	63,158	22,706	10.31%	29.01%	$ 37,394,426	$ 22,620,719	59.68%	93.41%	$ 592	$ 996
APR 2021	60,289	20,804	9.84%	26.27%	$ 34,399,972	$ 19,183,157	54.11%	91.39%	$ 571	$ 922
MAY 2021	60,769	20,073	9.95%	25.50%	$ 29,932,492	$ 16,294,407	52.78%	89.69%	$ 493	$ 812
JUN 2021	57,904	20,101	9.50%	25.58%	$ 28,630,750	$ 17,490,313	60.71%	91.70%	$ 494	$ 870
JUL 2021	56,503	20,462	9.29%	26.04%	$ 28,271,498	$ 18,721,856	67.41%	93.89%	$ 500	$ 915
AUG 2021	55,168	20,371	9.06%	25.98%	$ 26,588,079	$ 18,480,875	71.28%	94.64%	$ 482	$ 907
SEP 2021	52,850	19,155	8.66%	24.49%	$ 24,429,755	$ 17,193,816	72.73%	95.29%	$ 462	$ 898
OCT 2021	55,456	20,256	9.06%	25.78%	$ 25,248,689	$ 18,056,407	74.49%	96.29%	$ 455	$ 891
NOV 2021	54,781	20,541	8.90%	25.90%	$ 25,130,373	$ 18,307,184	74.91%	95.30%	$ 459	$ 891
DEC 2021	57,701	22,489	9.36%	28.06%	$ 27,226,609	$ 20,132,986	75.11%	94.50%	$ 472	$ 895
JAN 2022	61,267	24,170	9.91%	29.81%	$ 30,998,681	$ 22,260,918	72.14%	93.70%	$ 506	$ 921
FEB 2022	63,291	24,806	10.23%	29.69%	$ 34,220,521	$ 23,866,628	69.10%	92.55%	$ 541	$ 962
MAR 2022	68,439	26,100	11.04%	30.33%	$ 39,686,285	$ 26,301,342	65.37%	91.94%	$ 580	$ 1,008

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to OCA Set II (1 thru 51)
Delivered on March 2, 2022

OCA-II-15

Request:

Please provide in Excel format the number of CAP participants as of the end of the month by month since October 2018 to present inclusive. In addition to providing the total number, provide this number disaggregated by Federal Poverty Level.

Response:

Please see Attachment OCA-II-15. The Company does not maintain the historic CAP participation levels disaggregated by Federal Poverty Level.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division

CAP PARTICIPANTS

Oct-18	18,810	Oct-19	20,040	Oct-20	24,030	Oct-21	23,172
Nov-18	18,767	Nov-19	20,131	Nov-20	24,013	Nov-21	22,869
Dec-18	18,282	Dec-19	23,451	Dec-20	24,023	Dec-21	22,025
Jan-19	18,478	Jan-20	23,577	Jan-21	24,241	Jan-22	20,809
Feb-19	18,850	Feb-20	23,632	Feb-21	24,352	As of 2/14/2022	20,245
Mar-19	18,887	Mar-20	23,679	Mar-21	24,617		
Apr-19	19,122	Apr-20	23,729	Apr-21	24,617		
May-19	19,304	May-20	23,823	May-21	24,555		
Jun-19	19,490	Jun-20	23,838	Jun-21	24,164		
Jul-19	19,543	Jul-20	23,848	Jul-21	23,108		
Aug-19	19,702	Aug-20	24,025	Aug-21	23,656		
Sep-19	19,911	Sep-20	24,047	Sep-21	23,388		

UGI Utilities, Inc. - Gas Division
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UGI Gas 2022 Base Rate Case
Responses to OCA Set II (1 thru 51)
Delivered on March 2, 2022

OCA-II-16

Request:

Please provide in Excel format the number of CAP exits, by reason for the exit, by month since October 2018 to present inclusive.

Response:

Please see Attachment OCA-II-16-1. This is a report filed in the 2020 UGI Gas Base Rate Case that compiled this data from Oct 2017 thru February 2020. The previous file name was Attachment OCA-III-36. This file is available in PDF only.

Please see Attachment OCA-II-16-2. This is a new report detailing the data from March of 2020 to present.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc.

CAP Exits

Reason Removed	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20
Inactive - Removed	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Left Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Shut Off/Nonpayment	0	0	0	0	497	22	20	36	15	7	103	188	62	42	30	9	12	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Moved	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Over Income	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - No Benefit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Inactive - Graduated	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Failure to recertify	0	3	2	2	4	0	4	2	4	6	5	28	5	8	4	9	0	59	2	10	19	38	34	6	24	81	65	89	84
Removed - Failure to reduce usage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	24	0	0	7	0	0	0	0	0
Removed - Failure to apply for LIHEAP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Failure to apply for LIURP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Non payment	0	0	6	26	4	1	6	2	5	1	3	0	2	3	26	5	0	2	0	138	16	11	37	3	13	5	3	5	0
Removed - No access to meter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Unauthorized usage	0	1	0	0	0	0	0	0	1	0	0	0	1	0	2	1	0	0	0	0	2	1	1	0	1	0	0	2	0
Removed - Fraud	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1	1	0	0	0	0
Removed - Bankruptcy	0	1	0	0	1	2	2	1	3	2	2	1	1	1	1	0	0	0	1	1	0	2	0	2	2	1	0	1	2
Removed - Customer moved	109	261	399	184	221	227	188	223	221	245	276	294	264	322	320	196	152	322	210	266	387	324	415	327	278	322	286	389	391
Removed - Deceased	0	1	0	1	1	4	1	5	4	4	8	8	1	4	4	2	2	2	4	3	12	3	2	5	4	6	6	3	7
Removed - Seasonal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - No Benefit	11	43	25	10	3	4	8	10	6	3	11	10	36	170	9	3	2	0	0	8	3	6	7	5	5	2	50	52	4
Removed-Choose P/A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	27	10	18	47	31	71	39	16	1	3
Removed - Active collections	0	0	0	0	0	1	3	2	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Over income	14	6	4	6	1	13	19	19	30	24	23	21	33	24	13	16	17	33	34	21	19	21	28	24	26	25	19	32	21
Removed - Head of household not residing in the home	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	1	2	2	1	1	0	1	0	0
Removed - Invalid customer class - Health care facility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0	0
Removed - Invalid customer class - Foreign load	1	0	1	1	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Rate payer occupant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Landlord Tenant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Pool Heater	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Commercial Property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Removed - Invalid customer class - Customer Choice	0	0	0	0	2	0	1	1	0	0	0	1	0	0	1	0	0	0	0	4	0	0	0	0	0	0	0	0	0
Total	**135**	**317**	**437**	**230**	**734**	**274**	**253**	**302**	**290**	**293**	**431**	**551**	**406**	**574**	**411**	**242**	**188**	**419**	**276**	**479**	**493**	**426**	**573**	**412**	**426**	**481**	**447**	**574**	**512**

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to OCA Set II (1 thru 51)
Delivered on March 2, 2022

OCA-II-17

Request:

Please provide by year for the years 2018 to present inclusive:

a. Average number of confirmed low-income customers.

b. Average number of estimated low-income customers.

Response:

a. CONFIRMED LOW INCOME CUSTOMERS

2018	66,094
2019	74,493
2020	77,553
2021	78,450
2022*	81,081

* As of 1/31/22

b. ESTIMATED LOW INCOME CUSTOMERS

2018	159,649
2019	153,971
2020	151,918
2021	153,437

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to OCA Set II (1 thru 51)
Delivered on March 2, 2022

OCA-II-18

Request:

Please provide in Excel format a list of each:

a. Community served by the Company.

b. Zip code served by the Company.

Response:

Please see Attachments OCA-II-18-a and OCA-II-18-b.

Prepared by or under the supervision of: Daniel V. Adamo

UGI Utilities, Inc. - Gas Division
Docket No. R-2021-3030218
UGI Gas 2022 Base Rate Case
Responses to OCA Set VI (1 thru 6)
Delivered on March 10, 2022

OCA-VI-3

Request:

Reference UGI Statement No. 11, page 9, lines 6 through 9. For the past three years, please identify and quantify the erratic financial results experienced by the Company due to colder and warmer than normal weather.

Response:

UGI Gas margin for the 2019, 2020 and 2021 fiscal periods were $515.9 million, $530.2 million and $553.5 million respectively. New base rates were the driver of the higher margin in 2020 and 2021 resulting from filings under PA Docket Nos. R-2018-3006814 and R-2019-3015162 but it should be noted actual margin for 2020 and 2021 fell approximately $26 million and $19 million short of expected margin when compared to the approved total revenues pursuant to the Company's filed Proof of Revenues, which are based on normal weather, provided in those cases. The primary driver of variances was weather. Weather, as measured in heating degree days, for 2019, 2020 and 2021 fiscal periods were 3%, 9% and 9% warmer than normal, respectively. Additional historical heating degree data can be found in SDR-RR-11(a).

Prepared by or under the supervision of: John D. Taylor

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. - Gas Division	:	

REBUTTAL TESTIMONY OF HARRY S. GELLER, ESQ.

ON BEHALF OF

THE COALITION FOR AFFORDABLE UTILITY SERVICES AND

ENERGY EFFICIENCY IN PENNSYLVANIA ("CAUSE-PA")

May 17, 2022

PREPARED REBUTTAL TESTIMONY OF HARRY GELLER

Q: Please state your name, occupation, and business address.

A. My name is Harry S. Geller. I am an attorney. I am retired as the Executive Director of the Pennsylvania Utility Law Project (PULP), but have maintained an office at 118 Locust Street, Harrisburg, PA 17101 for the purpose of providing consulting services and assistance to low income individuals and the organizations which represent them in utility and energy matters.

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted direct testimony pre-marked as CAUSE-PA Statement 1 on behalf of the Coalition for Affordability Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA).

Q: What is the purpose of your rebuttal testimony?

A: My rebuttal testimony responds to the direct testimony of the Office of Consumer Advocate's expert witness, Mr. Roger Colton.[1] In Mr. Colton's direct testimony he makes several recommendations about much needed improvements to UGI's low income programs and customer service, many of which I agree with and support; however, I wish to voice some concerns and clarifications regarding some of Mr. Colton's recommendations. The specific recommendations made by Mr. Colton that I wish to address in my rebuttal testimony are his recommendations that UGI: (1) screen customers converting to natural gas in order to identify Confirmed Low Income customers for CAP enrollment and to provide LIURP investments to Confirmed Low Income customers as part of the process of converting those customers to natural gas, (2) expand its

[1] OCA St. 4.

existing LIURP spending by $1.425 million per year, and (3) establish measurable outcome objectives based on the performance of Pennsylvania Natural Gas utilities as a whole.

My rebuttal testimony is not intended to address every issue raised or otherwise discussed in the direct testimonies submitted by expert witnesses in this proceeding. Absence of a response to any specific recommendation or position of any witness does not indicate my agreement. Unless required for the context of providing further response to direct testimony, I will not reiterate the extensive agreements and evidence that I provided in my direct testimony. To the extent that an argument raised by any party is already sufficiently addressed in by direct testimony, I do not intend to respond, and stand on the evaluations, analyses, and recommendations contained in my direct testimony.

Q: Please summarize Mr. Colton's recommendation that UGI screen customers converting to natural gas in order to identify Confirmed Low Income customers and for CAP enrollment?

A: In Mr. Colton's direct testimony, he raises universal service issues related to UGI's process for converting consumers to natural gas service.[2] He points out that UGI Gas has converted nearly 30,000 customers in the past five years with 354 of those accounts being identified as confirmed low income customers, about half of which (168 accounts) were CAP participants.[3] However, he notes that UGI is only able to track the original customers who are active in the Customer Information System and remain at the converted premise; thus, these numbers likely understate the number of low income customers that UGI converted to natural gas during this time due to the

[2] OCA St. 4 at 15-23.
[3] Id. at 16.

high mobility rate of low income consumers and the fact that UGI only has only confirmed the low income status of a small fraction of its estimated low income customers.[4]

Mr. Colton further notes that, despite the historically low cost of natural gas service relative to deliverable fuels, without help, low income customers of UGI Gas often cannot pay their full UGI Gas home heating costs and that the addition of these struggling low income accounts without providing them necessary assistance likely imposes additional costs on other ratepayers.[5] To that end, he recommends that UGI Gas be directed to screen customers who the Company assists in their conversion to natural gas to identify those converted customers as Confirmed Low Income customers and to enroll those customers in CAP where appropriate.[6]

Q: What is your response to this recommendation?

A: I support Mr. Colton's recommendation and agree that screening gas conversion customers for CAP will help ensure that these customers can afford service and reduce uncollectible costs passed on to other customers. However, screening gas conversion customers for CAP enrollment will not address the low CAP participation numbers for UGI's existing low income customers that I explained my direct testimony.[7] Thus, the Commission should direct UGI to adopt both Mr. Colton's recommended CAP screening processes for gas conversion customers as well as my recommended CAP screening and referral processes for existing customers to help ensure that UGI achieves an adequate level of CAP enrollment to address both the existing need in its service territory and the additional need created by gas conversion.

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[4] Id.
[5] Id.
[6] Id. at 20.
[7] CAUSE-PA St. 1 at 20-21.

In my direct testimony I explained that less than a third of UGI's confirmed low income customers are enrolled in CAP and that UGI has had a consistently lower CAP participation rate compared to the industry average.[8] I further explained that UGI's total CAP enrollment declined over 16% when the Company resumed removing customers for failure to recertify after halting that practice due to COVID-19 concerns.[9] I recommended that UGI implement a process for simplified enrollment in CAP for non-CAP Low Income Home Energy Assistance Program (LIHEAP) recipients, inquire about the household income level of all customers seeking payment arrangements and provide a "warm transfer" for all potentially eligible customers to apply for CAP and other universal service programs, and conduct outreach to all customers who have been removed from CAP for failure to recertify since the expiration of the Commission's Emergency COVID-19 Order.

UGI must both address its problem with low CAP participation among currently identified low income customers, as well as address the problems identified by Mr. Colton with identifying and enrolling low income customers in the process of converting to gas. Thus, the Commission should order UGI to adopt both my recommendation to bolster CAP enrollment among UGI's existing customers and Mr. Colton's recommendations about increasing CAP enrollment among low income customers converting to gas service.

Q: Please summarize Mr. Colton's recommendation that UGI expand its LIURP spending?

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[8] Id. at 20-21.
[9] Id. St. 1 at 14, 21.

A: Mr. Colton recommends an additional, incremental component to its LIURP program that would provide LIURP investments to low income customers identified as part of the process of converting customers to natural gas and an expansion of UGI's existing LIURP budget.

Regarding the new incremental LIURP component for gas expansion customers, Mr. Colton explains that, in converting low income households from other fuels to natural gas, it should be the responsibility of UGI Gas to take reasonable steps to help control the added costs of those conversions to other residential ratepayers.[10] Mr. Colton recommends that UGI seek to ensure efficient natural gas usage through expanded energy efficiency and conservation.[11] He recommends that UGI add a new incremental component to its Low Income Usage Reduction Program (LIURP) through which it will provide LIURP investments to Confirmed Low Income customers as part of the process of converting those customers to natural gas, with a budget of \$524,450.[12]

Mr. Colton also recommends that UGI Gas undertake efforts to protect an expanded number of low income households through its LIURP due to the expanded hardships which UGI Gas will impose on its low income customers due to its rate proposal in this proceeding.[13] He explains that the primary way to redress the hardships which UGI's proposed rate increase will impose on the Company's low income customers is to undertake expanded efforts to make the housing of its low income customers as energy efficient as possible.[14] He recommends that UGI expand its LIURP program to reach 40% of confirmed low income households with usage over

[10] Id. at 19
[11] Id. at 20.
[12] Id.
[13] OCA St. 4 at 40.
[14] Id.

151 CCF or more within the next ten years.[15] To achieve this goal, he recommends that UGI expand its annual LIURP budget by $1.425 million.[16]

Q: What is your response to Mr. Colton's recommendations regarding expanding UGI's LIURP program?

A: I agree that the additional LIURP measures and funding proposed by Mr. Colton are necessary to offset the increased hardships that will be caused by UGI's proposed rate increase and to help reduce the additional cost to UGI customers from gas conversion customers. In my direct testimony, I recommended that UGI increase its LIURP budget by ***at least*** a percentage equal to the percentage increase of any approved residential rate increase.[17] After reviewing Mr. Colton's testimony, I believe that the additional $1.425 million LIURP increase recommended by Mr. Colton is necessary to adequately address need for energy efficiency measures among high usage, low income customers in light of UGI's proposed rate increase. UGI's LIURP is a critical universal service program designed to improve bill affordability, and that UGI's average bill savings per LIURP job was 20-25%.[18] However, the program is not operating at a rate sufficient to fulfill the estimated need for comprehensive usage reduction services within a reasonable amount of time. At UGI's current rate of production, it would take between 25-40 years for UGI to serve all eligible households in need of LIURP services.[19] Expanding UGI's LIURP budget by the $1.425 million recommended by Mr. Colton will substantially increase the rate at which UGI can provide LIURP services to serve the existing need in its service territory.

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[15] Id. at 40-41.
[16] Id. at 41.
[17] CAUSE-PA St. 1 at 29.
[18] Id. at 26.
[19] Id. at 27.

I also agree that Mr. Colton's recommended $524,450 incremental LIURP investments to low income customers identified as part of the process of converting customers to natural gas is necessary to both help low income gas conversion customers to afford service and to mitigate the potential impact of these customers struggles to afford service could have on existing customers. I also agree with Mr. Colton that this amount should be added on top of UGI's existing LIURP budget because the existing funds are necessary to serve the existing need in UGI's service territory.[20]

Q: Please summarize Mr. Colton's recommendation about establishing measurable outcomes for its universal service performance.

A: Mr. Colton voices many concerns similar to those raised in my direct testimony about UGI's need to better identify confirmed low income customers and enroll them in CAP and to have customers remain in CAP once enrolled.[21] Mr. Colton recommends the Commission establish three measurable Outcome Objectives that UGI Gas should seek to accomplish with respect to CAP.[22]

The Outcome Objectives he recommends are:

1. UGI Gas should achieve a Confirmed Low Income identification rate, as a percentage of estimated low income customers, no less than the Confirmed Low Income identification rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).

[20] Id. at 21.
[21] See OCA St. 4 at 27-31; See also CAUSE-PA St. 1 at 20-21.
[22] OCA St. 4 at 5.

2. UGI Gas should achieve a CAP participation rate, as a percentage of Confirmed Low Income customers, no less than the CAP participation rate of Pennsylvania natural gas utilities as a whole (excluding the UGI Gas companies).
3. UGI Gas should achieve a CAP default rate as a percentage of participants in the lowest poverty level range that is no less than the CAP default rate in that poverty level range for Pennsylvania gas utilities as a whole.[23]

Mr. Colton indicates that he would not recommend a system of rewards or penalties at this time but reserves the right to propose a system of penalties or rewards in a future rate case.[24]

Q: What is your response to these recommended measurable outcomes?

A: I support Mr. Colton's general idea to quantify established outcomes in CAP enrollment and retention. However, while it is concerning that UGI's identification of confirmed low income customers and CAP participation rates fall well below the industry standards for Pennsylvania natural gas utilities,[25] I do not believe that basing the measurable outcomes on the industry average statistics reported by other utilities is the appropriate metric against which to measure UGI's performance. The Public Utility Code requires that universal service programs are appropriately funded and available to meet the need for such services in the utility's service territory.[26] Nothing under the Code nor Commission regulations indicate that anything less than appropriate funding to fully meet low income needs is appropriate.

I believe that the success in identifying confirmed low income customers should be measured against full identification of all estimated low income customers and CAP enrollment

[23] Id.
[24] Id. at 26.
[25] CAUSE-PA St. 1 at 20-21; OCA St. 4 at 27-31.
[26] 66 Pa. C.S. § 2203(8).

should be measured against full enrollment of all confirmed low income customers. Any future penalty or rewards based on UGI's success in achieving these goals over time should be measured in percentage point increments as the Company progresses toward full identification and enrollment of all low income customers.

Q: Does this conclude your direct testimony?

A: Yes.

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2021-3030218
	:	
UGI Utilities, Inc. - Gas Division	:	

SURREBUTTAL TESTIMONY OF HARRY S. GELLER, ESQ.

ON BEHALF OF

THE COALITION FOR AFFORDABLE UTILITY SERVICES AND

ENERGY EFFICIENCY IN PENNSYLVANIA ("CAUSE-PA")

May 27, 2022

PREPARED SURREBUTTAL TESTIMONY OF HARRY S. GELLER, ESQ.

Q: Please state your name, occupation, and business address.

A. My name is Harry S. Geller. I am an attorney. I am retired as the Executive Director of the Pennsylvania Utility Law Project (PULP), but have maintained an office at 118 Locust Street, Harrisburg, PA 17101 for the purpose of providing consulting services and assistance to low income individuals and the organizations which represent them in utility and energy matters.

Q: Did you previously submit testimony in this proceeding?

A: Yes. I submitted direct testimony and rebuttal testimony pre-marked as CAUSE-PA Statement 1 and CAUSE-PA Statement 1-R on behalf of the Coalition for Affordability Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA).

Q: What is the purpose of your surrebuttal testimony?

A: My surrebuttal testimony responds to the rebuttal testimony of UGI witnesses Sherry A. Epler,[1] Constance E. Heppenstall,[2] John D. Taylor,[3] and Daniel V. Adamo;[4] and Bureau of Investigation and Enforcement (I&E) witness Zachari Walker.[5] My surrebuttal testimony is not intended to address every issue raised or otherwise discussed by these or other witnesses in rebuttal. Absence of response to any specific recommendation or position of any witness does not indicate my agreement. Unless required for context in providing a further response to rebuttal testimony, I will not reiterate the extensive arguments and evidence that I provided in my direct and rebuttal testimony. To the extent an argument raised by any party in rebuttal was already

[1] UGI St. 8-R
[2] UGI St. 10-R.
[3] UGI St. 11-R.
[4] UGI St. 12-R.
[5] I&E St. 1-R.

sufficiently addressed in direct, I do not intend to respond, and stand firmly on the evaluation, analysis, and recommendations contained in my direct testimony.

Q: How is your surrebuttal testimony organized?

A: I will begin by responding to the rebuttal testimony of UGI witness Adamo and I&E witness Walker regarding the Company's universal service programs. I will then respond to the rebuttal testimony of UGI witnesses Eppler and Adamo regarding my recommendation that the Company cease charging late fees and reconnection fees to confirmed low income customers. Finally, I will respond to UGI witnesses Eppler, Happenstal, and Taylor regarding the Company's proposal to increase its residential fixed customer charge.

I. UNIVERSAL SERVICE PROGRAMS

a. Low Income Usage Reduction Program

Q: Did you make recommendations in your direct testimony regarding UGI's Low Income Usage Reduction Program (LIURP)?

A: Yes. In my direct testimony I explained that UGI's LIURP is a critical program that helps low income customers reduce energy usage, thus improving bill affordability and, in turn, helping to reduce associated arrearages and terminations.[6] However, I further explained that despite the program's value and impressive results, UGI's LIURP is not operating at a rate sufficient to fulfill the demonstrated need within a reasonable amount of time.[7] As such I recommended that UGI increase its LIURP budget by an amount at least proportional to the percentage residential bill increase in this case.[8]

[6] CAUSE-PA St. 1 at 26.
[7] Id.
[8] Id.

Q: Please briefly summarize the testimony regarding the Company's LIURP to which you wish to respond.

A: UGI witness Adamo argues that the LIURP regulations set forth factors to be considered when revising a utility's LIURP funding and that none of the parties in this proceeding have testified to any of those factors.[9] Also, both UGI witness Adamo and I&E witness Walker argue that it is not appropriate to increase LIURP funding through this proceeding because the LIURP budget was approved in the Company's most recent USECP proceeding.[10] Mr. Walker also points out that I made a miscalculation regarding UGI's current LIURP budget.[11]

Q: How do you respond to Mr. Walker's assertion that you made a calculation error regarding the Company's LIURP budget?

A: Mr. Walker is correct. In my direct testimony, I recommended that the Company increase its LIURP budget by a percentage at least equal to the percentage of any residential bill increase approved in this proceeding.[12] I provided an example based on the Company's proposed increase of 9.5% to the bill of a residential customer with average usage.[13] However, in my example, I only included the LIURP budget for UGI's former North and South divisions and failed to account for the LIURP budget attributable to the Central division. So, Mr. Walker is correct, that my example should have been based on a total LIURP budget of $3,714,350, and the 9.5% an increase should have resulted in a budget of <u>$352,863</u>. However, I did subsequently, in rebuttal, adjust my LIURP budget recommendation based on the testimony and recommendation of OCA witness Colton.

[9] UGI St. 12-R at 29-30.
[10] <u>Id.</u> at 30-31; I&E St. 1-R at 4.
[11] I&E St. 1 at 5.
[12] CAUSE-PA St. 1 at 29.
[13] <u>Id.</u>

Q: What adjustments did you make to this recommendation in your rebuttal testimony?

A: After reviewing the testimony of OCA witness Roger Colton,[14] I agreed with Mr. Colton that the additional $1.425 million LIURP increase recommended by Mr. Colton is necessary to adequately address the need for energy efficiency measures among high usage, low income customers in light of UGI's proposed rate increase.[15]

Q: What are the LIURP funding factors that witness Adamo claims were not addressed by the parties?

A: Mr. Adamo states that no parties addressed the factors to be considered regarding LIURP funding, as set forth in 52 Pa. Code § 58.4(c).[16] Those factors are:

> (c) Guidelines for revising program funding. A revision to a covered utility's program funding level is to be computed based upon factors listed in this section. These factors are the following:
>
> > (1) The number of eligible customers that could be provided cost-effective usage reduction services. The calculation shall take into consideration the number of customer dwellings that have already received, or are not otherwise in need of, usage reduction services.
> >
> > (2) Expected customer participation rates for eligible customers. Expected participation rates shall be based on historical participation rates when customers have been solicited through approved personal contact methods.
> >
> > (3) The total expense of providing usage reduction services, including costs of program measures, conservation education expenses and prorated expenses for program administration.
> >
> > (4) A plan for providing program services within a reasonable period of time, with consideration given to the contractor capacity necessary for provision of services and the impact on utility rates.

Q: Did you address these factors in your direct testimony?

A: Yes. I addressed all of these factors in my direct testimony.

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[14] OCA St. 4 at 40-41.
[15] CAUSE-PA St. 1 at 6-7.
[16] UGI St. 12-R at 29-30.

(1) Regarding the number of eligible customers, I cited to UGI's most recent needs assessment, which indicates that, based on the number of customer dwellings that have already received, or are not otherwise in need of, usage reduction services, "In UGI's former South District, it would take 25 years to serve estimated need; while in UGI's former North District, it would take an estimated 40 years to serve those in need."[17]

(2) Regarding the expected participation rates, I pointed out that, "In 2021, LIURP services were provided to just 378 households across its service territory."[18]

(3) Regarding the total expense of providing LIURP services, I explained that, "The Company's current total LIURP budget is $3,705,350. Thus, if UGI's rates were approved as proposed, UGI's LIURP budget should be increased, at a minimum, by 9.5% or $352,008 – distributed proportionately according to the existing need in UGI's former North, South, and Central rate districts."[19]

(4) Regarding a plan for providing program services within a reasonable period of time, I explained that I further explained that, it will take between 25-40 years for UGI to serve identified needs across its service territory,[20] and that "UGI's LIURP is not operating at a rate sufficient to fulfill the estimated need for comprehensive usage reduction services within a reasonable amount of time."[21]

[17] CAUSE-PA St. 1 at 27.
[18] Id. at 26-27.
[19] Id. at 29.
[20] Id. at 27.
[21] Id. at 26.

Q: How do you respond to UGI witness Adamo's and I&E witness Walker's assertions that it is not appropriate to increase LIURP funding through this proceeding because the LIURP budget was approved in the Company's most recent USECP proceeding.

A: I disagree. It is both appropriate and relevant for a utility and the Commission to examine the Company's LIURP budget in the context of a proposed rate increase in order to help mitigate the impact of the proposed increase on its low income customers. UGI is proposing to substantially increase residential rates through this proceeding, and if approved, the proposed rate increase will exacerbate existing levels of unaffordability for UGI's low income, high usage customers, causing additional need for LIURP services to help mitigate the bill impacts and prevent additional arrearages and terminations. It is common for LIURP budgets to be adjusted in rate cases in order to help mitigate the impact of the rate increases on low income, high usage customers and help prevent increased arrearages and terminations associated with the residential bill increase.

As I explained in my direct testimony, low income customers already suffer disproportionate energy burdens and struggle to pay their UGI bills and often make impossible trade-offs to stay connected to service.[22] If the Commission approves any rate increase in this proceeding, an adjustment to UGI's LIURP budget will be needed to help mitigate the substantial financial impact on UGI's most vulnerable customers.

[22] CAUSE-PA St. 1 at 9-10.

b. Operation Share

Q: Did you make recommendations in your direct testimony regarding UGI's Hardship Fund (Operation Share)?

A: Yes. In my direct testimony, I explained that UGI's low income termination rates have increased significantly since the expiration of COVID-19 emergency measures.[23] I further explained that these high termination rates amongst confirmed low income and CAP customers demonstrates there is need for substantial improvements in UGI's Operation Share Program.[24] To that end, I recommended that UGI increase its Operation Share budget and increase the maximum grant amounts available to low income customers at risk of termination.[25]

Q: Please briefly summarize the testimony regarding Operation Share to which you wish to respond.

A: UGI witness Adamo argues that a funding increase for Operation Share is not necessary because the Company has already supplemented funding to the program over the past few years due to the COVID-19 pandemic and because federal programs, such as Emergency Rental Assistance Program (ERAP) and Pennsylvania Homeowner Assistance Fund (PAHAF), and the Low Income Home Energy Assistance Program (LIHEAP), support low income customers.[26] He also argues that increasing the maximum grant amount for customers would reduce the number of customers who are able to take advantage of the program's funding due to the proposed higher grant levels.[27]

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[23] Id. at 14-17.
[24] CAUSE-PA St. 1 at 30.
[25] Id. at 30-32.
[26] UGI St. 12-R at 33.
[27] Id.

Q: How do you respond to UGI witness Adamo's argument that additional Operation Share funds are not necessary?

A: I recognize that the Company has increased Operation Share funds over the past few years due to the unprecedented need caused by the COVID-19 pandemic; however, more is needed to help reduce low income termination rates in UGI's service territory. As I explained in my direct testimony, despite the availability of these additional Operation Share funds and the increase in the number of grants awarded, UGI low income customers still experienced a disproportionate increase in termination rates – clear evidence of existing unaffordability.[28] I further explained:

> In 2021, UGI's confirmed low income termination rate was more than double its 2019 rate and its CAP termination rate was more than triple 2019 levels, while UGI's general residential termination rate remained in line with 2019 levels. At the end of the 2021-2022 winter moratorium, 7% of confirmed low income customers and 23% of CAP customers were at risk of termination, compared to only 5% of residential customers as a group. **This disproportionate increase in low income termination rates occurred despite the fact that the Operation Share program was carrying a significantly increased budget throughout 2021**.[29]

Moreover, ERAP and PAHAF are only temporary programs and will not be available to help offset the impact of this rate increase. These emergency relief programs are time-limited, and some have already run out of funds or will soon close to new applicants.[30] Additional Operation Share funding is needed to reduce UGI's disproportionately high low income termination rates.

[28] CAUSE-PA St. 1 at 30.
[29] Id. (emphasis added).
[30] See Pa. Department of Human Services, Emergency Rental Program (ERAP) Instructions and Requirements, March 2021, available at: https://www.dhs.pa.gov/ERAP/Documents/ERAP%20I%20R%20Revised%20December%202021.pdf ; See also Pa. Housing Finaance Agency, Pa. Homeowner Assistance Fund Program Plan, October 2021, available at: https://www.phfa.org/forms/haf/pahaf-plan.pdf .

Q: How do you respond to UGI witness Adamo's argument that increasing the grant amount will reduce the number of customers able to access grants?

A: I stand by my recommendation that increased grant amounts are needed to curb disproportionately high low income termination rates in UGI's service territory.[31] The documented increase in UGI's low income termination rates shows that additional assistance is needed to offset the financial impact of UGI's rate increase and keep low income customers connected to service. Increasing the Operation Share budget as recommended in my direct testimony, as well as that of OCA witness Colton and CEO witness Brady, will help ensure that funds are available to customers, in crisis, who need them.

c. OCA Recommended Measurable Outcomes

Q: Are there other issues regarding low income customer service that you wish to address?

A: Yes. In his direct testimony, OCA witness Roger Colton recommended that UGI adopt several measurable outcomes in an effort to improve the Company's performance identifying confirmed low income customers, enrolling them in CAP, and keeping them in the program once enrolled.[32] In my rebuttal testimony, I voiced support for Mr. Colton's recommendations and suggested some clarifications.[33]

[31] CAUSE-PA St. 1 at 30-31.
[32] OCA St. 4 at 5.
[33] CAUSE-PA St. 1-R at 7-9.

Q: Is there testimony from the Company about this subject to which you wish to respond?

A: Yes. UGI witness Adamo argues that there is not enough time to investigate and evaluate proposals related to the Company's universal service programs in the context of this base rate case.[34] He argues that these changes should be considered in the context of UGI's next Universal Service and Energy Conservation Plan (USECP).[35]

Q: What is your response?

A: Mr. Colton's recommended measurable outcomes are not necessarily related to making changes to the Company's universal service programs but are instead focused on ensuring that the Company be required to improve its customer service to low income customers.[36] All of these metrics are customer service metrics, necessary to assess UGI's operations, management efficiencies, and quality of service. These customer service issues are squarely within the bounds of the current rate case. Further, the Company's universal service rider, uncollectible expenses, and terminations are all tied to the performance of its universal service programs. The Choice Act requires that universal service programs are appropriately funded and available and operated in a cost-effective manner.[37] The Choice Act also requires that the Commission, ***at a minimum***, continue the level and nature of the consumers protections, policies and services to assist low income retail gas customers to afford natural gas services.[38]

[34] UGI St. 12-R at 10.
[35] Id.
[36] OCA St. 4 at 5.
[37] 66 Pa. C.S. §2203(8).
[38] 66 Pa. C.S. §2203(7).

Despite Mr. Adamo's claim that there is not enough time to evaluate these recommendations in the context of a rate case, universal service programming has a direct impact on rates for participants and other ratepayer and must not be divorced from base rate proceedings, which provide a more appropriate level of due process review. USECP proceedings only provide a limited ability for noncompany parties to evaluate the level and nature of the consumer protections, policies and services to assist low income customers. Unlike a rate case, where parties are able to engage in a factual inquiry into a utility's provision of service to all consumers through discovery and submit sworn expert testimony before an Administrative Law Judge, a USECP offers only a brief comment and reply comment period with no opportunity for formal discovery or to be heard by an Administrative Law Judge. As such, this rate case is an appropriate venue for the evaluation of the customer service and collections metrics proposed by Mr. Colton, as well as the program modifications which I proposed in my direct testimony.

II. LATE FEES AND RECONNECTION FEES

Q: Did you make recommendations in your direct testimony regarding UGI's late fees and reconnection fees?

A: Yes. In my direct testimony I explained that late fees function as a punitive measure for low income customers by punishing them for their inability to afford their bills and add additional costs that contribute to the disproportionately high rate of low income terminations.[39] I further explained that these regressive charges disproportionately impact low income Black and Hispanic households, families with young children, and medically vulnerable households.[40] I also explained that the combination of UGI's late fees and reconnection fees raise additional barriers to the ability

[39] CAUSE-PA St. 1 at 38.
[40] Id.

of low income households to reconnect to service, which increases the public safety risks associated with termination of natural gas service.[41] As such, I recommended that UGI stop charging late fees and reconnection fees to low income customers.[42]

Q: Please briefly summarize the testimony regarding the Company's late fees and reconnection fees to which you wish to respond.

A: UGI witness Adamo states that he partially agrees with my position and indicates that confirmed low income customers who receive LIHEAP crisis grants or who are on CAP are not assessed late fees by the Company.[43] However, he argues that reconnection fees facilitate customer engagement in order to prevent customers from being terminated.[44] UGI witness Eppler responded to my recommendation by stating that if UGI were to waive reconnection fees, rate revenues would need to be adjusted downward and would add to the Company's requested increase by $275,000 to recover the lost revenue.[45]

Q: How do you respond to Mr. Adamo's indication that low income customers enrolled in CAP or receive LIHEAP are not currently charged late fees?

A: I stand by my recommendation that UGI exempt all its confirmed low income customers from both late fees and reconnection fees. UGI's confirmed low income customers are not limited to only CAP customers and LIHEAP recipients. The Company also identifies and confirms low income status for LIURP Participants with income at or below 150% of the federal poverty level (FPL), Operation Share participants with income at or below 150% FPL, and customers who

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[41] Id. at 38.
[42] Id. at 39.
[43] UGI St. 12-R at 48.
[44] Id.
[45] UGI St. 8-R at 27-28.

provided income information to their local Community Based Organization (CBO) for purposes of security deposit waivers.[46] All of these subgroups have provided evidence demonstrating their inability to afford natural gas service without assistance. Late fees and reconnection fees are a hinderance to these customers' ability to maintain service. The Company should exempt them from these regressive, burdensome charges.

Q: How do you respond to Mr. Adamo's statement that late fees and reconnection fees serve as a deterrent to terminations?

A: Late fees and reconnection fees should not be used as a deterrent or punishment for low income customers who do not earn enough to pay their monthly expenses. Furthermore, I am unable to see the logic that charging these fees serves to facilitate engagement in order to prevent disconnects from occurring in the first place. My recommendation was limited to confirmed low income customers, which is a segment of UGI's customer base in need of assistance. My personal experience, and likely the philosophy behind UGI's current policy of waiving fees for its LIHEAP and CAP recipients, is that these households are unable to pay the current level of their bills and adding additional fees will only serve to further push them to delinquency and service loss. As I indicated in my direct, the average income for UGI's confirmed low income customers is just $1,007 per month and, under the Company's rate proposal, the average residential heating customer's bill would be $108.01 per month.[47] Thus, the natural gas bill burden for the average confirmed low income customer at average usage levels would be 10.7 % – *not including the additional burden of electric service*. Adding UGI's $73.00 reconnection charge to a customer

[46] CAUSE-PA to UGI IV-1.
[47] CAUSE-PA St. 1 at 38.

who cannot afford this overwhelming energy burden and is subsequently terminated would require an additional 7.2% of their monthly income to reconnect to service.[48]

The confirmed low income customers who have demonstrated eligibility for a deposit waiver, for LIURP, or Operation Share crisis assistance are in the same economic category as those LIHEAP and CAP recipients for whom UGI already waives late fees. Further, UGI's reconnection fees add a substantial barrier to reconnection for customers in this situation and it is not just or reasonable to penalize these customers for their inability to pay, or to throw up additional barriers that compound unaffordability and impede their ability to reconnect to service.

Q: How do you respond to Mr. Eppler's concerns about lost revenue from not charging reconnection fees to low income customers?

A: I recognize Mr. Eppler's concerns about the possibility of lost revenue from reconnection fees charged to confirmed low income customers. As I explained above, the purpose of late fees and reconnection fees should not be to punish or deter late payment. In the context of the Company's proposed $82.7 million dollar proposed increase, the reduction of $275,000 as a result of the eliminated reconnection fees for confirmed low income customers is a reasonable amount to help ensure that confirmed low income customers who are terminated for nonpayment are not unduly hindered from reconnecting to service.

[48] Id.

III. RESIDENTIAL FIXED CUSTOMER CHARGE

Q: Did you make recommendations in your direct testimony regarding UGI's proposal to increase its residential fixed customer charge?

A: Yes. In my direct testimony I explained that increasing the fixed residential customer charge undermines the ability of consumers to control costs through energy efficiency and conservation, which is problematic for low income customers who struggle to afford service and rely on offsetting high bills through usage reduction.[49] I further explained that increasing the fixed residential charge undermines the explicit goals of the Low Income Usage Reduction Program (LIURP) to "reduce residential energy bills."[50] I recommended that the fixed charge not be increased and that if the Commission grants any rate increase it should be assessed to the volumetric charge.[51]

Q: Please briefly summarize the Rebuttal testimony regarding the Company's residential fixed customer charge to which you wish to respond.

A: UGI witness Eppler states that low income customers are, on average, higher use customers and will thus benefit from a higher fixed charge.[52] He also argues that increasing the fixed charge will not affect customers' incentive to conserve because the Company will still increase its volumetric charge as well.[53] UGI witness Taylor argues that dedicating resources to reducing customer bills through energy efficiency measures does not reduce the costs incurred by the utility and, therefore, these actions are "not an efficient use of our resources as a society."[54]

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[49] CAUSE-PA St. 1 at 32-33.
[50] 52 Pa. Code § 58.1.
[51] CAUSE-PA St. 1 at 35.
[52] UGI St. 8-R at 19.
[53] UGI St. 8-R at 19.
[54] UGI St. 11-R at 31.

Q: How do you respond to Mr. Eppler's assertion that low income customers are, on average, higher use customers.

A: It is troubling that low income customers are experiencing the levels of high usage laid out in Mr. Eppler's testimony. Low income households tend to live in smaller homes or apartments, which means the higher average usage is likely more easily controlled with basic efficiency measures and home repair. High usage low income customers are in need of energy efficiency and conservation programming to reduce their usage and remediate unsustainably high energy burdens. They are not helped in the long run by increasing the fixed residential customer charge. UGI should be taking additional steps to respond to the demonstrated need for energy efficiency and conservation measures through its LIURP.

The explicit goal of LIURP is to "reduce residential energy bills" by providing energy efficiency measures to low income households.[55] UGI's LIURP is effective at achieving this goal and producing meaningful average bill savings of 20-25% for the few hundred low income households who are able to receive LIURP services each year, and the program's effectiveness at achieving bill reduction is tied directly to volumetric rates.[56] However, despite these impressive results, UGI's LIURP is not operating at a rate sufficient to fulfill the estimated need for services.[57] To address the problematic high usage of low income customers, UGI needs to ramp up LIURP production. Raising the fixed charge will only serve to negate the bill impact of usage reduction

[55] CAUSE-PA St. 1 at 33-34; See also 52 Pa. Code § 58.1 ("The programs are intended to assist low-income customers conserve energy and reduce residential energy bills. The reduction in energy bills should decrease the incidence and risk of customer payment delinquencies and the attendant utility costs associated with uncollectible accounts expense, collection costs and arrearage carrying costs.").
[56] CAUSE-PA St. 1 at 33.
[57] CAUSE-PA to UGI I-13.

measures because, as more residential customer costs are shifted to the fixed charge, the achievable bill savings will necessarily erode.[58]

Q: How do your respond to Mr. Epplers assertion that increasing the fixed charge will not affect customers' incentive to conserve usage, because the Company will still increase its volumetric charge?

A: While customers will still be able to reduce costs through energy efficiency, the achievable bill savings will decrease according to how much the fixed charge is increased. As I explained in my direct, if the proposed increase in the fixed customer charge is approved, UGI customers will lose the ability to control as much as 3.7% of their monthly bill through energy conservation, which will reduce the bill savings for customers who implement EE&C measures and negatively impact the effectiveness of LIURP to achieve meaningful bill reductions for low income consumers.[59] Thus, I stand by my recommendations that the fixed charge should not be increased and that the Company's LIURP production should be increased to adequately meet the demonstrated need.[60]

I also note that, setting aside the impact increased fixed charges will have on a consumers' incentive to conserve, the fact remains that increasing the fixed customer charge shifts risk and costs to consumers and skims off bill savings achievable through conservation.

[58] Id.
[59] CASUE-PA St. 1 at 34.
[60] See CAUSE-PA St. 1 at 40.

Q: How do you respond to UGI witness Taylor's argument that attempting to achieve residential bill reduction through energy efficiency measures is "not an efficient use of our resources as a society" because it does not reduce the costs incurred by the utility?[61]

A: I totally disagree. The LIURP regulations state that the program is intended to "assist low-income customers conserve energy and **reduce residential energy bills**."[62] The regulation further states that, "The reduction in energy bills should decrease the incidence and risk of customer payment delinquencies and the attendant utility costs associated with uncollectible accounts expense, collection costs and arrearage carrying costs."[63] Reducing energy bills for low income customers helps decrease the incidence and risk of customer payment delinquencies and the attendant utility costs associated with uncollectible accounts expense, collection costs and arrearage carrying costs. [64] It also helps prevent terminations, and in turn reduce homelessness, blight, fires, and the public health impacts of termination.[65] Furthermore, there are other non-monetary societal benefits achievable through comprehensive energy efficiency, including health benefits from improved indoor air quality and stable temperatures, improved household comfort, and reduced greenhouse gas emissions; however, my direct testimony was limited to the effect of energy efficiency measures on low income bills.

Q: Does this conclude your surrebuttal testimony?

A: Yes.

[61] UGI St. 11-R at 31.
[62] 52 Pa. Code § 58.1.
[63] Id.
[64] CAUSE-PA St. 1 at 17-18, 26-27.
[65] Id.

COMMISSION ON ECONOMIC OPPORTUNITY

CEO Statement No. 1

Direct Testimony of Eugene M. Brady

Pennsylvania Public Utility Commission

v.

UGI Utilities, Inc. – Gas Division

Docket Number: R-2021-3030218

Q. Please state your full name and business address.

A. Eugene M. Brady, 165 Amber Lane, PO Box 1127, Wilkes-Barre, Pennsylvania 18703-1127.

Q. By whom are you employed and in what capacity?

A. I am employed by the Commission on Economic Opportunity (CEO) as Executive Director.

Q. What are the interests of the Commission on Economic Opportunity in this rate case?

A. The Commission on Economic Opportunity is a non-profit organization serving the low-income and elderly in Luzerne County, PA. In a typical year, the Commission serves more than 25,000 Luzerne County residents, of which 98% are at or below 150% of the federal poverty level. It is part of our responsibility to our constituency to advocate for their interests in regulatory proceedings and this proposed request will certainly have an impact upon those low-income ratepayers. In addition to the affordability of rates, CEO is particularly interested in the ability of our clients to save money through conserving energy.

Q. **What background and experience in energy issues qualify you and the Commission on Economic Opportunity to participate in this case?**

A. I have served as the Executive Director of the Commission since 1978. During my tenure CEO's experience and the expertise of its staff in energy programs has been recognized on state and national levels. CEO's energy related programs have been acknowledged by receipt of a Superior Achievement Award from the United States Department of Energy. CEO has weatherized more than 25,000 homes under the U.S. Department of Energy Weatherization Assistance Program. The organization also serves as a subcontractor for the PPL Electric Utilities' WRAP Program (LIURP) and the Low Income Usage Reduction Programs operated by the UGI Gas and Electric Divisions. In addition to energy conservation, the Commission is the contracted operator of Customer Assistance Programs sponsored by PPL and UGI and operates the hardship assistance funds for each of those utility companies. CEO is also the PA Department of Public Welfare's contracted operator of the crisis component of the Low Income Home Energy Assistance Program (LIHEAP) in Luzerne and Wyoming Counties. CEO was also a major contractor for PPL in the Low Income Renewable Energy Pilot, and secured funding and installed several solar thermal water heating systems for the former PG Energy and UGI Gas Division.

Throughout my career I have served on numerous Boards, Committees and Task Forces in the energy field under the auspices of the US Department of Energy, The PA Department of Community & Economic Development, and the PA Public Utility Commission. Presently, I serve on the Board of Directors of the National Center for Appropriate Technology; I am on the Board of the National Community Action Foundation, the Chair of the Pennsylvania Weatherization Providers Task Force, and Chair of the Department of Community & Economic Development Weatherization Policy Advisory Council.

Additionally, CEO has been an active party in many restructuring and rate cases before the PUC including the last rate cases of UGI Electric (R-2021-3023618) and UGI Gas (R-2019-3015162).

Q. Please describe the areas of your testimony.

A. In its request for a rate increase the Company does not propose any increase in funding or measures that would help low-income customers to deal with the proposed rate increase. The Company's pending Universal Service and Energy Conservation Plan (M-2017-2598190) that sets funding for its universal service programs up to and including 2025 does not consider the impact of this rate increase. Further, an increase in the fixed monthly charge, as requested by the Company, would negatively impact a customer's motive and ability to conserve energy. The Company's proposal if granted would increase rates, discourage conservation, and leave a customer with less ability to conserve energy and less ability to reduce their electric bills. Despite the impact of its proposal on residential customers, and in particular low-income customers, the Company's proposal offers nothing in the way of changes or increases in funding to its low-income programs, programs that would help mitigate the negative impact of the Company's proposals.

The Company is requesting a rate increase of $82.7M, of which $68.1M, or 82.3%, will be allocated to the residential class. An average residential customer using 73.1Ccf of gas per month will see their bill increase from $98.62 to $108.01, an increase of approximately 9.5% for the residential class. Despite this increase and despite the impact it will have on low-income customers, the Company is not proposing any changes to its low-income programs, there is nothing proposed that will help low-income customers deal with the impact of this proposed rate increase. Specifically, my testimony will address how the Company's proposal to increase its monthly fixed service charge effects a customer's ability to conserve and how the impact of the Company's proposal could be mitigated through changes to the funding level of the Company's low-income reduction program (LIURP) and other universal service programs.

Q. Before addressing the specifics of your testimony, do you have general concerns regarding this rate case?

A. Yes. As I indicate above, I am concerned that this proposed increase does not come with any proposals that will help low-income customers deal with the impact of the rate increase and rate design. A large part of the residential customer's increase will be due to an increase in the fixed monthly customer charge, from $14.60 to $19.95, an increase of 36.6% This increase in the monthly fixed charge concerns me, as it has the Commission in recent cases, because it discourages conservation and impacts a customer's ability to save money through conservation; as the Company moves towards charging customers based upon the Company's fixed costs and away from a customer's consumption there is less incentive, and ability, to conserve. One of the only defenses a family, particularly a poor family, has against the sharp increases in energy costs is to conserve – lower the thermostat, seal air leaks, change filters regularly, add more insulation, get a more efficient heating unit, etc. The Company's proposal to increase the fixed costs greatly impacts a customer's motive to conserve and the ability to lessen the impact of any rate increase. The combined effect of an increase in rates and an increase in fixed monthly charges, without any changes to universal service funding, not only results in higher rates but also lessens the ability of customers to deal with those increases. In particular, the negative impact would be particularly harsh on the Company's low-income customers and the Company's proposed request ignores the interests of its low-income customers. The Gas Choice Act requires that the Commission ensure that universal service programs are 'appropriately funded and available' and the result of this proceeding will impact the question of whether the Company's universal service programs are appropriately funded and available.

Q. How does the effect of the Company's requests impact upon your testimony in this case?

A. I do not believe that the Commission should allow an increase in rates and allow an increase in the fixed monthly customer charge without requiring an increase in universal service funding that would allow some relief to low-income customers. For a typical residential customer, a 9.5% increase is substantial. The Company has indicated that the average annual income of its low-income customers if $12,084 so one can see the dramatic impact a 9.5% increase would have on low-income customers. High utility costs are not the only challenge for a poor person; we are in a time of great inflation where the costs of essential items-housing, transportation, food etc.-have been increasing at rates not seen for decades. Our agency has been helping low-income people for years and knows firsthand that they face financial challenges on many fronts and a dramatic increase in the costs for essential items can have a devastating impact. That negative impact goes beyond just an increase in rates in this case because the increase in the fixed monthly charge makes it more difficult for a consumer to lessen the impact of an increase in rates through conservation. Accordingly, I believe that any increase in rates and a rate design that discourages conservation should be accompanied by measures that allow a customer to conserve energy and thereby lower their utility bill.

Q: Does CEO take a position on whether the Company's rate increase should be granted?

A: No. Our concern is with the combination of the Company's request to increase rates and to increase the fixed portion of a customer's bill without any increases proposed for universal service funding or measures to help its low-income customers.

Q: What impact would the Company's proposed rate design have on low-income customers?

A: The more a customer's bill is made up of fixed charges the less incentive and ability there is for a low-income customer to save money by conserving energy. In this case the Company is proposing a 36.6% increase of its fixed monthly charge, from $14.60 to $19.95. I am concerned about this proposal and CEO opposes any increase to the fixed monthly customer charge.

Q: Why does CEO oppose an increase to the fixed monthly customer charge?

A: In prior cases, former PUC Commissioner Cawley has expressed concerns about proposals to increase the fixed portion of a customer's bill or any proposal that would impact a customer's motive and ability to conserve. In a National Fuel Gas case (No. R-

00061493) Commissioner Cawley issued a statement while the case was pending concerning NFG's proposal to increase its fixed monthly customer charge. That statement read in relevant part:

> "This proposed change raises important policy issues that affect this Commission's goals of promotion and encouragement of conservation of natural resources, including natural gas. Given the extremely volatile and currently high natural gas prices facing this nation, a policy that does not optimally reward consumers for conservation efforts, but instead charges fixed fees regardless of usage, should, I feel, be addressed by the parties to this case."

We share Commissioner Cawley's concerns and believe that fixed monthly charges should be held in check.

Q. What would you like to address concerning the Company's LIURP program?

A. The Company has indicated that as of January 31, 2022, it has 81,081 confirmed low-income customers but estimates that is had 153,437 low-income customers in 2021. The Company's last needs assessment submitted as part of the Company's pending USECP found that there were 5,251 customers in need of LIURP measures in the Company's former UGI South district and 4,756 in need of LIURP in the Company's former North division. The former Central district was not part of that needs assessment because of the low number of customers in that district at the time of the assessment. The Company has stated that it would take 25 years to meet that need in the South district and

40 years to meet the need in the North district. The unmet need is compounded by the fact that during the COVID-19 pandemic the Company's LIURP budget was not fully spent.

Despite this large unmet need for LIURP services snd its proposal to increase rates in this proceeding, the Company is not proposing any increase in LIURP funding. As a result of this proceeding rates are likely to increase, a customer's ability to conserve will decrease (if the fixed monthly charge is increased) yet no relief is being provided to customers that would allow them to increase their conservation of energy and decrease their monthly bills. No progress will be made towards reducing the number of low-income customers in need of LIURP services.

Q. Do you believe that funding for LIURP should be increased and if so why?

A. I do believe that funding for LIURP should be increased in light of the above-described need and the effect, if approved, of the Company's requests in this proceeding.

Q. Do you have a specific recommendation regarding LIURP funding?

A. Yes. Current funding for LIURP is set at $3,634,350 annually and I am recommending that the annual funding for LIURP be increased by $750,000 effective upon the effective date of any rate increase emanating from this proceeding.

Q. What is the basis for recommending that LIURP funding be increased by $750,000 annually?

A. Initially, based upon the Company's own needs assessment there are approximately 10,000 low-income customers in need for LIURP services in just two of the three prior UGI Gas districts and as indicated above it will take 25 years in one of those districts and 40 years in the other to meet that need. So, in order to begin to meet that need the number of LIURP jobs will need to be increased as will LIURP funding. With an additional increase the Company can begin to meet the need that exists in its service territory.

The Company plans to complete 481 LIURP jobs per year across its service territory. I believe a good target would be an additional 100 jobs per year across the Company's territory. At a rounded LIURP job cost of $7,500 per job this would require an increase of $750,000 in additional annual funding. Further, as I mentioned above, often the only defense that a poor person has to rising utility costs is conservation and LIURP services increase a person's ability to conserve. LIURP provides conservation measures that a poor person could otherwise not afford. With the many economic challenges facing a low-income person, they lack the resources to improve energy efficiencies in the home. Additionally, because of the effect of the Company's proposed increase on the residential class and the move towards higher fixed charges, more help has to be given to the low-income residential customer in the form of improving their ability to conserve and thereby control their energy costs.

Q. Are there other reasons why you propose increasing LIURP funding by $750,000 annually?

A. Yes. Because I believe, like the Commission, that the energy conservation measures which result from a well funded LIURP program are an essential part of helping low income consumers deal with rising energy costs. The Commission has also found great value in LIURP programs by stating:

> "The Commission finds that LIURP has been one of the Commonwealth's most successful programs for assisting low-income customers. The Commission has found that LIURP reduces bad debt by reducing customers' bills. Customers who receive LIURP services are able to pay their entire bill plus contribute to their arrearage."

PUC Order on Duquesne Light's Restructuring, R-00974104, page 293.

And I believe that an effective LIURP program is especially important now in light of this Company's current request for a rate increase and change in rate design.

Although I believe the Company's other universal service programs serve important needs, they help a low-income customer only after a problem has arisen, whether it be arrearages or other crisis that impacts a person's ability to pay. Whereas a well-funded usage reduction program helps a poor person avoid a crisis by allowing for greater conservation and thereby a reduction in their monthly bills while at the same time promoting the common good that comes from energy conservation. I believe these are the reasons why the Commission has long recognized the value of a well-funded LIURP program.

Q. Do you have any general comments on the Company's universal service programs?

A. This Company has a history of using community-based organizations in the administration and implementation of its universal service programs, and I commend them for doing so. And it has indicated that it intends to continue to use community-based organizations relative to its universal service programs. As part of this proceeding, the Company should be directed to continue to use community-based organizations in the administration and implementation of its universal service programs as it has traditionally.

These organizations serve thousands of low income and disadvantaged members of the community; they have direct knowledge of the barriers and impediments to self-sufficiency, and continually innovate and evolve the service delivery system to better meet the needs of the population they serve. Community based organizations are governed by volunteer Boards of Directors; accountable to the communities they serve, and are not conflicted by a duty to shareholders and investors. The focus and active experience of community-based organizations make them singularly suited to speak for the needs of the community. Local, experienced community-based organizations must continue to operate these programs; the CEO operates as a one stop facility for the energy problems of the poor. This system has been shown to be efficient, cost-effective and serves as a vital link between utility programs and the low-income customers served by those programs.

Q. Do you have any recommendations regarding other universal service programs?

A. Yes. As part of the settlement in this Company's last rate case, the Company agreed to increase Company donations to its Operation Share Hardship fund by $1,000,000 on a one-time basis. Considering the current request to increase rates, the number of low-income customers served and the inflationary pressures those customers face I am recommending that the Company's annual contribution to its hardship fund be increased by $1,000,000.

Q. Can you summarize your recommendations?

A. I am recommending the following:

1. That annual LIURP funding be increased by $750,000 with any unspent portion being carried over to the following year;

2. That the Company's request to increase its fixed monthly customer charge be denied;

3. That the Company be directed to continue to use community-based organizations as it has traditionally done in the administration and implementation of its universal service programs;

4. That the Company's annual contribution to its hardship fund be increased by $1,000,000.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, ET AL.	:	
V.	:	R-2021-3030218
UGI UTILIITES, INC. – GAS DIVISION	:	

CERTIFICATE OF SERVICE

The undersigned certified that he served a copy of the foregoing Commission on Economic Opportunity's Statement No. 1 – Direct Testimony of Eugene M. Brady upon the following participants via electronic mail on this 20th day of April, 2022:

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I&E Statement No. 1
Witness: Zachari Walker

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Direct Testimony

of

Zachari Walker

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

TAXES

CASH WORKING CAPITAL

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<u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zachari Walker, and my business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT BACKGROUND?

A. My education and employment background is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to review the base rate filing of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) and recommend adjustments to the Company's proposed operating and maintenance (O&M) expenses, taxes, and cash working capital (CWC) claims for the fully projected future test year (FPFTY) ending September 30, 2023.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 1 contains schedules that support my direct testimony.

Q. PLEASE SUMMARIZE THE COMPANY'S REQUESTED REVENUE INCREASE.

A. UGI Gas' base rate case was filed on January 28, 2022, with a requested increase of $82,742,000[1] to claimed present rate revenues of $1,062,724,000 resulting in an overall revenue requirement of $1,145,466,000 for the FPFTY.[2]

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.

A. The following table summarizes my recommended adjustments:

[1] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-2.
[2] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-2.

	UGI Gas Claim	I&E Recommended Allowance	I&E Adjustment
O&M Expenses:			
Employee Activity Costs	$588,226	$217,935	($370,291)
Advertising Expense	$1,901,541	$1,016,363	($885,178)
Membership Dues	$1,115,404	$961,406	($153,998)
Interest for Customer Deposits	$972,000	$648,000	($324,000)
Payroll Expense	$82,929,000	$80,677,324	($2,251,676)
Employee Benefits Expense	$22,117,000	$21,510,994	($606,006)
Total O&M Adjustments			**($4,591,139)**
Taxes:			
Payroll Taxes	$6,927,000	$6,738,985	($188,015)
Total Tax Adjustments			**($188,015)**
Rate Base:			
Cash Working Capital	$62,148,000	$61,313,000	($835,000)
Total Rate Base Adjustments			**($835,000)**

I&E OVERALL RECOMMENDED REVENUE REQUIREMENT

Q. WHAT IS I&E'S TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement is $1,094,441,000. This recommended revenue requirement represents an increase of $18,072,000 to the I&E-adjusted present rate revenues of $1,076,369,000. This total recommended allowance incorporates my adjustments made in this testimony to O&M expenses, taxes, and CWC, and those recommended adjustments made in the testimony of I&E witnesses Anthony Spadaccio,[3] Brian LaTorre,[4] Ethan Cline,[5] and Esyan Sakaya.[6]

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[3] I&E Statement No. 2.
[4] I&E Statement No. 3.
[5] I&E Statement No. 4.
[6] I&E Statement No. 5.

A calculation of I&E's recommended revenue requirement is shown below:

UGI Utilities Inc. - Gas Division		TABLE I			
R-2021-3030218		INCOME SUMMARY			
($ in Thousands)					
	9/30/23	INVESTIGATION & ENFORCEMENT			
	Proforma	[---]			
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	1,062,724	13,645	1,076,369	18,072	1,094,441
Deductions:					
O&M Expenses	689,306	-996	688,310	298	688,608
Depreciation	125,537	-3,666	121,871		121,871
Taxes, Other	13,658	-188	13,470	0	13,470
Income Taxes:					
Current State	4,364	2,109	6,473	1,776	8,249
Current Federal	15,064	3,992	19,056	3,360	22,416
Deferred Taxes	20,732	0	20,732		20,732
ITC	-324	0	-324		-324
Total Deductions	868,337	1,251	869,588	5,434	875,022
Income Available	194,387	12,394	206,781	12,639	219,420
				12,638	219,419
Measure of Value	3,169,023	-146,707	3,022,316	1	3,022,316
Rate of Return	6.13%		6.84%		7.26%

EMPLOYEE ACTIVITY COSTS

Q. WHAT IS INCLUDED IN EMPLOYEE ACTIVITY COSTS?

A. Per the Company's response to I&E-RE-24(b),[7] the employee activity costs consist of expenses related to the company picnic, employee service awards, an annual holiday breakfast, and "other activity." In further explanation, the Company states "other activity" includes, but is not limited to, department

[7] I&E Exhibit No. 1, Schedule 1, pp. 1-2.

meetings, employee gifts, field employee welfare (water, ice, etc.), special activity gifts, flowers, and cards.[8]

Q. WHAT IS THE COMPANY'S CLAIM FOR EMPLOYEE ACTIVITY COSTS?

A. UGI Gas' FPFTY expense claim for Employee Activity Costs is $588,226.[9] A breakdown of the FPFTY claim is as follows:[10]

Company Picnic	$213,000
Service Awards	$165,996
Annual Holiday Breakfast	$24,800
Other Activity	$184,430
Total	**$588,226**

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

8 I&E Exhibit No. 1, Schedule 1, p. 2.
9 UGI Gas Book II, SDR-RR-30(e).
10 I&E Exhibit No. 1, Schedule 1, p. 2.

Q. WHAT IS YOUR RECOMMENDATION FOR EMPLOYEE ACTIVITY COSTS?

A. I recommend an allowance of $217,935 or a reduction of $370,291 ($588,226 - $217,935) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the historic year 2019 level expense inflated to the FPFTY. The 2019 data represents the most recent known and measurable data prior to the effects of the COVID-19 pandemic. In response to I&E-RE-24, the Company provided a breakdown of employee activity costs by year for 2019 through the FPFTY.[11] There is a considerable difference in expense level during 2020 and the HTY, seemingly due to the impact of the COVID-19.[12] Going forward the Company plans to resume the Company picnic in 2022 and 2023;[13] however, it appears the Company has accepted the new level of expense as the new normal.[14] At this juncture, given that we are still in the midst of a pandemic, it is impossible to determine whether all employees would be willing to gather at an optional Company picnic. Even if all UGI Gas employees attend the picnic, the $123 ($213,000[15] ÷ 1,731 employees[16]) cost per employee is not prudent.

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[11] I&E Exhibit No. 1, Schedule 1, p. 2.
[12] I&E Exhibit No. 1, Schedule 1, p. 1, Response Part B.
[13] I&E Exhibit No. 1, Schedule 1, p. 1, Response Part B.
[14] I&E Exhibit No. 1, Schedule 1, p. 2.
[15] I&E Exhibit No. 1, Schedule 1, p. 2.
[16] I&E Exhibit No. 1, Schedule 2, p. 2.

Q. HOW DID YOU CALCULATE YOUR RECOMMENDATION?

A. First, I started with the known and measurable historic expense level from 2019, \$189,346, provided in response to I&E-RE-24.[17] Using the CPI Inflation Calculator, I converted the September 30, 2019 expense to the September 30, 2021 (2021) equivalent after inflation, \$202,289.[18] Next, I applied an average of consumer price index (CPI)[19] inflation factors of 6.0% [(7.9% + 5.8% + 6.6% + 3.8%) ÷ 4] and 2.8% [(3.0% + 2.9% + 2.6% + 2.6%) ÷ 4] for the four quarters in the 2022 fiscal year and the four quarters in the 2023 fiscal year, respectively, to adjust the 2021 equivalent value to the 2023 equivalent value. This yields \$217,935 [{\$202,289 x (1+6.0%)} x (1+2.8%)] for my FPFTY recommended allowance. My recommended allowance of \$217,935 represents a reduction of \$370,291 (\$588,226 - \$217,935) to the Company's FPFTY employee activity costs claim.

<u>COVID-19 RELATED UNCOLLECTIBLE ACCOUNTS EXPENSE</u>

Q. WHAT IS UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. Uncollectible accounts expense are specific receivables that are determined to be uncollectible, in whole or in part, either because the debtors do not pay or because the creditor finds it impracticable to enforce payment. Those accounts deemed uncollectible are charged against income as uncollectible accounts expense.

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17 I&E Exhibit No. 1, Schedule 1, p. 2.
18 I&E Exhibit No. 1, Schedule 3.
19 Blue Chip Financial Forecasts Vol 41, No. 4, April 1, 2022, p. 2.

Q. HOW DO UTILITIES RECOGNIZE UNCOLLECTIBLE EXPENSE FOR RATEMAKING PURPOSES?

A. Generally, for ratemaking purposes, utilities compute uncollectible expense on an annual prospective basis. While the uncollectible expense is a prospective claim, the proper calculation begins with a historic analysis of actual net write-offs to gross revenues to develop a historic write-off ratio. Thus, net write-offs are gross write-offs less recoveries of amounts previously written off. This ratio is applied to projected revenues to determine the proper prospective allowance. Normally, the historic analysis is based on several years of data.

Q. WHAT CLAIM ARE YOU ADDRESSING HEREIN FOR UNCOLLECTIBLE EXPENSE?

A. I am addressing the COVID-19 related cost recovery associated with uncollectible accounts expense.

Q. WHAT IS THE COMPANY'S CLAIM FOR COVID-19 RELATED UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. The Company's total claim for COVID-19 cost recovery of deferred uncollectible accounts expense is $1,503,000 which represents $607,000 through September 30, 2020, and $896,000 through 2021.[20] This produces a ten-year amortization of

[20] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-11.

$150,000 ($1,503,000 ÷ 10 years). The Company is also proposing regulatory asset treatment going forward for incremental uncollectible costs above what is included in this proceeding to be recovered in the next base rate proceeding.[21]

Q. WHAT IS THE BASIS FOR THE COMPANY'S COVID-19 RELATED UNCOLLECTIBLE ACCOUNTS EXPENSE CLAIM?

A. The Company followed the Commission's guidance in the May 13, 2020 Secretarial Letter regarding *COVID-19 Cost Tracking and Creation of Regulatory Asset, Docket No. M-2020-3019775* (May 13, 2020 Secretarial Letter), taking the difference between the amount of uncollectible expense claimed in the prior base rate case and the amount experienced at the fiscal year ended September 30, 2020, and the amount experienced at the fiscal year ended September 30, 2021. The Company included this amount in a regulatory asset and is following the 10-year amortization period in line with the Settlement Agreement in the previous base rate case at Docket No. R-2019-3015162.[22] Additionally, the Company does not agree that the accumulation of COVID-19 related uncollectible deferrals should cease upon the effective date of new rates in the instant proceeding.[23] In this regard, the Company states it should be able to continue to accumulate and defer costs above the normalized level as approved within the Company's new rates as a

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[21] I&E Exhibit No. 1, Schedule 4, p. 1, Response Part B.
[22] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-11.
[23] I&E Exhibit No. 1, Schedule 4, p. 1, Response Part B.

regulatory asset citing higher than normal delinquency rates on COVID-19 related payment arrangements.[24]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR THE CONTINUED DEFERRAL OF COVID-19 RELATED UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. I accept the Company's total deferral claim of $1,503,000 for the 2020 and 2021 excess COVID-19 related uncollectible accounts, as well as the 10-year amortization period as approved by the Commission as part of the settlement in the UGI Gas 2020 BRC proceeding.[25] However, I disagree that the Company should be allowed to continue recording a regulatory asset for ongoing COVID-19 related incremental uncollectible costs after the effective date of new rates for the instant proceeding. Upon the effective date of new rates for this proceeding, the Company will have a new uncollectible accounts expense percentage built into the rate formula that accounts for the increased delinquency rates and higher customer balances.

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[24] I&E Exhibit No. 1, Schedule 4, p. 1, Response Part B.

[25] *Pa. PUC, et al. v. UGI,* Docket Nos. R-2019-3015162 (Order entered on October 8, 2020).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. First, the Company has provided evidence that COVID-19 related uncollectible accounts expenses are included in forward-looking routine uncollectible accounts expense as seen in the discrepancy between the rate of accrual provided in UGI Gas Book I, Attachment III-A-5 and UGI Gas Book V, Schedule D-11. The Company states the 2020 Uncollectible Accounts Expense on Schedule D-11, $13,417[26] (12,810[27] + $607[28]), includes the COVID-19 related uncollectible accounts expense, and the 2021 Uncollectible Accounts Expense, $13,706[29] ($12,810[30] + $896[31]), includes the COVID-19 related uncollectible accounts expense. Therefore, allowing the Company to continue the deferral past the effective date of new rates in this proceeding would allow for redundant recovery of the COVID-19 related uncollectible accounts since they are already built into the routine uncollectible accounts percentage on Schedule D-11 for the FPFTY calculation.[32]

Additionally, in the 2020 Joint Petition for Unopposed Settlement – UGI Gas et al., page 21, item 49, the Company states COVID-19 Pandemic Costs may include reasonable and prudently incurred…annual uncollectible accounts expense beginning with the fiscal year period ending September 30, 2020 and continuing

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[26] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-11, line 2.
[27] UGI Gas Book I, Attachment III-A-5.
[28] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-11, Footnote 1.
[29] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-11, line 3.
[30] UGI Gas Book I, Attachment III-A-5.
[31] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-11, Footnote 1.
[32] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-11, lines 1-4.

for annual periods thereafter until the effective date of the Company's next base rate filing. This statement in the previous base rate case Settlement Agreement indicates the Company agreed not continue to accumulate COVID-19 related costs beyond the effective date of new rates for the instant proceeding.

ADVERTISING EXPENSE

Q. WHAT IS THE COMPANY'S CLAIM FOR ADVERTISING EXPENSE?

A. The Company's FPFTY claim for advertising expense is $1,901,541.[33]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. In response to I&E-RE-30, the Company indicated it has an integrated advertising campaign promoting the benefits of domestic natural gas, including messaging that relates to the overall economic value of natural gas versus other energy sources and benefits of high efficiency natural gas appliances.[34]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

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[33] UGI Gas Book 1, Attachment III-A-25.
[34] I&E Exhibit No. 1, Schedule 5, p. 1, Response Part C.

Q. WHAT IS YOUR RECOMMENDATION FOR ADVERTISING EXPENSE?

A. I recommend an allowance of $1,016,363 or a reduction of $885,178 ($1,901,541 - $1,016,363) to UGI Gas' FPFTY advertising expense claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. In response to I&E-RE-31, the Company provided a breakdown of the other advertising programs included in its advertising expense claim.[35] The listed categories: Sponsorship, Builder Meetings/Trade Shows, Branded Promotional Items, Customer Promotional Offers, and Miscellaneous Advertising, are represented by images provided in response to I&E-RE-30.[36] These representations merely promote the Company's image without promoting the benefits of domestic natural gas. Therefore, I recommend the other advertising programs in the amount of $885,178[37] be disallowed for ratemaking purposes as they are not necessary to ensure safe and reliable gas service.

MEMBERSHIP DUES

Q. WHAT IS INCLUDED IN MEMBERSHIP DUES?

A. The Company's claim includes payments to industry organizations with the

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35 I&E Exhibit No. 1, Schedule 6, p. 2.
36 I&E Exhibit No. 1, Schedule 5, pp. 2-5.
37 UGI Gas Book I, Attachment III-A-25.

intention of improving the welfare, educational, social, and economic climate in the Company's local communities.[38]

Q. WHAT IS THE COMPANY'S CLAIM FOR MEMBERSHIP DUES?

A. UGI Gas is claiming membership dues of $1,115,404 for the FPFTY.[39]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR MEMBERSHIP DUES?

A. I recommend an allowance of $961,406, or a decrease of $153,998 ($1,115,404 - $961,406) to the Company's membership dues claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on disallowing, for ratemaking purposes, claims for numerous organizations where the Company has not provided adequate support for their necessity to ensure safe and reliable gas service.[40] The recommended decrease to the FPFTY claim is the total of the following: Allentown Economic Development Corporation ($5,148); Economic Development Company of Lancaster County ($32,964); Lebanon Valley Economic Development Corporation

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[38] I&E Exhibit No. 1, Schedule 7.
[39] UGI Gas Book II, Attachment SDR-RR-30.
[40] I&E Exhibit No. 1, Schedule 8, pp. 1-3.

($8,244); Lehigh Valley Economic Development Corporation ($21,636); Northeastern Pennsylvania Alliance ($1,704); Penn's Northeast ($5,664); Pennsylvania Chamber of Business & Industry ($66,521); and Pennsylvania Economy League ($12,117). The total of the organizations listed above is my recommended reduction of $153,998 ($5,148 + $32,964 + $8,244 + $21,636 + $1,704 + $5,664 + $66,521 + $12,117) to the Company's FPFTY membership dues claim.

INTEREST ON CUSTOMER DEPOSITS

Q. WHAT IS THE COMPANY'S CLAIM FOR INTEREST ON CUSTOMER DEPOSITS?

A. The Company's FPFTY expense claim for interest on customer deposits is $972,000.[41]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. UGI Gas is required to pay interest on customer deposits that it holds in accordance with tariff requirements. The interest is calculated by using the average level of customer deposits anticipated for the FPFTY times the required interest rate (4.50%) anticipated for the FPFTY, as published by the Department of Revenue and as required under the Company's tariff.[42] Additionally, in response

[41] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-15, line 7.
[42] UGI Gas Statement No. 2, pp. 21-22.

to I&E-RE-59, the Company stated 4.50% is the maximum lawful rate of interest for residential mortgages for December 2021 as published by the Department of Banking and Securities on November 13, 2021.[43]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR INTEREST ON CUSTOMER DEPOSITS?

A. I recommend an allowance of $648,000, or a reduction of $324,000 ($972,000 - $648,000) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Per the Pennsylvania Secretary of Revenue, the current interest rate for Title 72 taxes is 3% for 2021 and 2022.[44] This interest rate is revised every year in December. The Company's FPFTY begins in October 2022 and the Pennsylvania Department of Revenue may revise the current interest rate in December 2022; however, as of today, this is speculative. Thus, I am recommending the allowance of $648,000 ($21,600,000[45] x 3.00%) using the current interest rate for Title 72 taxes.

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[43] I&E Exhibit No. 1, Schedule 9.
[44] I&E Exhibit No. 1, Schedule 10.
[45] UGI Gas Statement No. 2, p. 21.

PAYROLL EXPENSE

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR PAYROLL EXPENSE?

A. The Company's payroll expense claim includes operations and maintenance salaries and wages for union, exempt, and non-exempt employees.

Q. WHAT IS THE COMPANY'S CLAIM FOR PAYROLL EXPENSE?

A. The Company's FPFTY claim for payroll expense is $82,929,000.[46]

Q. WHAT IS THE BASIS FOR THE COMPANY'S PAYROLL EXPENSE CLAIM?

A. The Company's claim for payroll expense is based on the HTY budgeted headcount with an increase of 43 regular employees in the FTY and an additional 27 regular employees to the FTY headcount.[47] The claim includes compensation changes targeted at increasing retention and recruitment.[48]

Q. DO YOU AGREE WITH THE COMPANY'S PAYROLL EXPENSE CLAIM?

A. No.

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[46] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-7, p. 1.

[47] UGI Gas Book II, SDR-RR-20.

[48] UGI Gas Book II, SDR-RR-20.

Q. WHAT IS YOUR RECOMMENDATION FOR PAYROLL EXPENSE?

A. I recommend an allowance of $80,677,324, or a reduction of $2,251,676 ($82,929,000 - $80,677,324) to the Company's FPFTY claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on an employee vacancy adjustment for unfilled positions included in the Company's claim.

Q. PLEASE EXPLAIN YOUR RECOMMENDED VACANCY ADJUSTMENT.

A. My recommended vacancy adjustment is based on an average employee vacancy rate of 2.74% [(2.63% + 5.04% + 0.54%) ÷ 3] determined from the response to I&E-RE-63.[49] I calculated the monthly vacancy rate by dividing the actual monthly vacancies by the budgeted positions for each month in the fiscal years ended September 30, 2019; September 30, 2020; and September 30, 2021.[50] Next, I calculated the annual average vacancy rate for each fiscal year and then calculated the overall average vacancy rate,[51] as summarized in the table below:

Fiscal Year Ended	Vacancy Rate
September 30, 2019	2.63%
September 30, 2020	5.04%
September 30, 2021	0.54%
Average Vacancy Rate	2.74%

[49] I&E Exhibit No. 1, Schedule 11, pp. 1-3.
[50] I&E Exhibit No. 1, Schedule 12.
[51] I&E Exhibit No. 1, Schedule 12.

The average of the annual employee vacancy rate, 2.74% [(2.63% + 5.04% + 0.54%) ÷ 3] yields 47 (1,731 FPFTY budgeted employees[52] x 0.0274) vacant employee positions for the FPFTY. Finally, I multiplied the vacant positions by the average annual payroll, $47,908 ($82,929,000 ÷ 1,731), per employee which produces my recommended payroll adjustment of $2,251,676 ($47,908 x 47 positions). This adjustment results in my recommended payroll allowance of $80,677,324 ($82,929,000 - $2,251,676).

Q. EXPLAIN YOUR RATIONALE FOR THE VACANCY ADJUSTMENT.

A. The Company budgeted its payroll expense based on the average employee count of 1,731 at the end of the FPFTY as compared with the HTY employee count of 1,667 employees,[53] which includes 20 anticipated additional new employees in the FPFTY.[54] It is unreasonable to assume that the Company will fill and maintain 100% full staffing of 1,731 budgeted positions in the FPFTY based on its own historic vacancy records of the fiscal years ended September 30, 2019, 2020, and 2021. As discussed above, using my recommendation, the Company would reflect a normal vacancy rate of 2.74% in the FPFTY. Additionally, as evidenced at the end of the first quarter of the FTY, the Company experienced an overall increase to a 2.24% vacancy rate and an average vacancy rate of 1.73%.[55] These historic

[52] I&E Exhibit No. 1, Schedule 2, p. 2.
[53] I&E Exhibit No. 1, Schedule 2, p. 2.
[54] UGI Gas Statement No. 9, p. 16.
[55] I&E Exhibit No. 1, Schedule 12.

vacancy rates support my recommended 47 vacant positions based on an average vacancy rate of 2.74% for an adjustment to payroll expense.

With the current COVID-19 pandemic, the Company may continue to face challenges to fill all positions as budgeted in the FTY and FPFTY. Additionally, there will always be a certain level of normal vacancies due to retirements, resignations, transfers, layoffs, etc., on a day-to-day operating basis, which are unpredictable and there will always be search and placement time involved in filling normal employee vacancies as well as newly added positions. Such vacancies will yield an annual savings in payroll costs that must be reflected in payroll expense to eliminate an unreasonable impact to ratepayers.

EMPLOYEE BENEFITS

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR EMPLOYEE BENEFITS EXPENSE?

A. The Company's employee benefits claim includes insurance premiums for medical, dental, basic life, long term disability, accidental death and dismemberment, and business travel accident insurances.[56]

[56] UGI Gas Book II, Attachment SDR-RR-22.

Q. WHAT IS THE COMPANY'S CLAIM FOR EMPLOYEE BENEFITS EXPENSE?

A. The Company is claiming employee benefits expense of $22,177,000 for the FPFTY.[57]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has based its FPFTY claim for employee benefits expense on budgeted 2022 fiscal year health and dental insurance expense.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR EMPLOYEE BENEFITS EXPENSE?

A. I recommend an allowance of $21,510,994, or a reduction of $606,006 ($22,117,000 - $21,510,994) to the Company's FPFTY claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on an employee vacancy adjustment as noted in the payroll expense section above. I applied the 2.74% vacancy rate to the Company's

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[57] I&E Exhibit No. 1, Schedule 13, p. 2.

claim for employee benefits to calculate my employee benefits expense adjustment. The result is my recommended adjustment of $606,006 ($22,117,000 x 0.0274).

PAYROLL TAXES

Q. WHAT IS THE COMPANY'S CLAIM FOR PAYROLL TAXES?

A. The Company is claiming $6,927,000 for FPFTY payroll taxes.[58]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim is based on the FPFTY payroll expense claim including an adjustment for an increase in payroll expense[59] and the social security and Medicare taxes, federal unemployment tax, and Pennsylvania state unemployment tax.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR PAYROLL TAXES?

A. I recommend an allowance of $6,738,985, or a reduction of $188,015 ($6,927,000 - $6,738,985) to the Company's FPFTY claim.

[58] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-31, lines 4-6.
[59] UGI Gas Statement No. 2, p. 25.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on my recommended total payroll expense adjustment of $2,251,676 and calculated by applying the Company's payroll tax rate of $8.35% (7.59% + 0.14% + 0.62%).[60] The result is my recommended adjustment of $188,015 ($2,251,676 x 0.0835), a reduction to the Company's FPFTY payroll tax claim.

<u>**CASH WORKING CAPITAL**</u>

Q. WHAT IS A CASH WORKING CAPITAL (CWC) ALLOWANCE FOR RATEMAKING PURPOSES?

A. CWC includes the amount of funds necessary to operate a utility during the interim period between the rendition of service, including the payment of related expenses, and the receipt of revenue in payment for services rendered by the utility.

Q. HOW DOES THE COMPANY CALCULATE ITS CWC CLAIM?

A. The Company calculates its CWC claim by using a lead/lag study. A lead/lag study measures the differences in time between: (1) the time services are rendered until payment of those services is received; and (2) the time between the point when a utility has incurred an expense and the actual payment of the expense.

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[60] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-32, lines 3,7, and 9.

Stated a different way, the lead/lag study measures how many days exist on an average between the midpoint of the service period and the date the payment is made.

Q. DO YOU AGREE WITH THE COMPANY'S USE OF THE LEAD/LAG METHOD?

A. Yes. I agree with the Company's use of the lead/lag method for CWC calculation.

Q. WHAT IS THE COMPANY'S CWC CLAIM?

A. The Company's FPFTY CWC claim is $62,148,000.[61]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an allowance of $61,313,000, or a reduction of $835,000 ($62,148,000 - $61,313,000) to the Company's claim.[62]

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation includes modification of the Company's claim based on my

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[61] UGI Gas Book V, Exhibit A – Fully Projected, Schedule C-4, p. 1.
[62] I&E Exhibit No. 1, Schedule 14, p. 1, line 5.

recommended adjustments to O&M expenses as discussed previously in this testimony and the other I&E witnesses as explained below.

Q. HOW DO YOUR PROPOSED ADJUSTMENTS, DISCUSSED ABOVE, IMPACT YOUR RECOMMENDATION FOR CWC?

A. All O&M adjustments that are cash-based expense claims are included when determining the Company's overall CWC requirement. Therefore, CWC was adjusted to reflect these recommended adjustments. To reflect the I&E recommended adjustments, I modified the Company's electronic CWC file as shown on UGI Gas Book V, Schedule C-4, pp. 1, 2, 3, and 7, for each recommended adjustment.[63]

Q. SUMMARIZE WHERE EACH OF THE I&E RECOMMENDED O&M EXPENSE ADJUSTMENTS ARE REFLECTED IN THE CWC COMPUTATION.

A. **Expense Lag Days - Payroll:**

I recommended a payroll expense adjustment of ($2,251,676) in the Expense Lag - Payroll, which is reflected as reduction to line 3 of the Company's Exhibit A – Fully Projected, Schedule C-4, p. 2 as shown in I&E modified Schedule C-4.[64]

[63] I&E Exhibit No. 1, Schedule 14, pp. 1-4.
[64] I&E Exhibit No. 1, Schedule 14, p. 2, line 3.

Expense Lag Days – Purchased Gas Costs:

Mr. Cline recommended a purchased gas expense increase of $7,729,631, which is reflected as an addition in the FPFTY purchased gas costs of $404,893,000 ($397,163,000 + $7,729,631) in the Purchased Gas Costs Expense Lag Days calculation.[65]

Expense Lag Days – Other Expenses:

Mr. LaTorre and I recommended the following expense adjustments in the Expense Lag Days - Other Expenses as an overall decrease of $6,662,328 of the Company's Exhibit A – Fully Projected, Schedule C-4, p. 2 as shown in I&E modified Schedule C-4:[66]

Other Expenses	Reduction
Employee Activity Costs	$370,291
Advertising Expense	$885,178
Membership Dues	$153,998
Interest on Customer Deposits	$324,000
Rate Case Expense	$422,000
Environmental Remediation Expense	$1,861,600
OSHA/Emergency Temporary Standard Compliance Costs	$1,851,240
Employee Benefits Expense	$606,006
Payroll Taxes	$188,015
Total	**$6,662,328**

65 I&E Exhibit No. 1, Schedule 14, p. 2, line 4.
66 I&E Exhibit No. 1, Schedule 14, p. 2, line 5.

Revenue Lag Calculations:

The Company provided a correction to miscellaneous revenue reducing present rate revenue by $1,003,000 as seen in the Company's response to I&E-RS-27.[67] Mr. Cline recommended an adjustment to increase present rate revenue by $14,648,202. The net of the two adjustments, $13,645,202, is reflected as an addition in the total account receivable amount of $1,304,884,202 ($1,327,239,000 + $13,645,202) and in the total sales revenue of $857,917,202 ($844,272,000 + $13,645,202) in the Revenue Lag calculation.[68]

Interest Payment Lag Calculations:

Mr. Sakaya recommended an adjustment to rate base of $145,872,000 ($137,649,000 + $8,223,000), which is reflected as a reduction to rate base resulting in an updated total of $3,023,154,000 ($3,169,026,000 - $145,872,000) in the Interest Payments Lag calculation.[69]

Q. DOES YOUR RECOMMENDED ALLOWANCE REPRESENT A FINAL RECOMMENDED ALLOWANCE FOR CWC?

A. No. All adjustments to the Company's claims for revenues, expenses, taxes, and rate base must be consistently brought together in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This

[67] I&E Exhibit No. 4, Schedule 5.
[68] I&E Exhibit No. 1, Schedule 14, p. 3, lines 15 and 18.
[69] I&E Exhibit No. 1, Schedule 14, p. 4, line 1.

process, which is known as iteration, effectively prevents the determination of a precise calculation until such time as all adjustments have been made to the Company's claim.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Zachari Walker

Professional and Educational Background

<u>Experience</u>:

<u>Pennsylvania Public Utility Commission</u>, Harrisburg, Pennsylvania
March 2021 to Present:
Fixed Utility Financial Analyst, Bureau of Investigation and Enforcement

<u>Bridgestone Retail Operations, LLC,</u> Nashville, Tennessee
December 2014 to July 2020:
Business Manager
Evaluated and validated accounting entry postings. Monitored, reconciled, and corrected daily transactions and accounts. Ensured accuracy of daily reports of business and researched inaccuracies. Utilized data analysis to determine key performance indicators and corresponding trends.

<u>Education/Professional Development</u>:

Bridging the Gap, Holly Ridge, North Carolina, 2021
Business Analyst Blueprint Training Program, 36 PD hours earned

Stevenson University, Stevenson, Maryland, 2014
Bachelor of Science, *magna cum laude*, Business Administration
Concentration in Finance

<u>Professional Affiliations</u>:

International Institute of Business Analysis (IIBA), Pickering, Ontario, Canada
Active Member 2021

<u>Utility-Related Trainings & Other Courses/Webinars</u>:

Pennsylvania Public Utility Commission Rate School 2022, January 18-February 8, 2022

Michigan State University IPU Accounting and Ratemaking Course 2021, September 14-16, 2021

NARUC Staff Subcommittee on Accounting & Finance, Spring 2021 Virtual Conference, April 6-8, 2021

<u>Testimony Submitted</u>:

R-2021-3026682	City of Lancaster – Bureau of Water
R-2021-3026116	Borough of Hanover – Hanover Municipal Water Works
R-2021-3025206	Community Utilities of Pennsylvania Inc. – Water Division
R-2021-3025207	Community Utilities of Pennsylvania Inc. – Wastewater Division

I&E Statement No. 1-R
Witness: Zachari Walker

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Rebuttal Testimony

of

Zachari Walker

Bureau of Investigation & Enforcement

Concerning:

LOW-INCOME USAGE REDUCTION PROGRAM

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<u>INTRODUCTION OF WITNESS</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zachari Walker, and my business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME ZACHARI WALKER WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 1 AND THE SCHEDULES IN I&E EXHIBIT NO. 1?

A. Yes.

Q. DOES YOUR REBUTTAL TESTIMONY INCLUDE AN ACCOMPANYING EXHIBIT?

A. Yes. I&E Exhibit No. 1-R contains schedules that support my rebuttal testimony.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address the direct testimony of (1) Office of Consumer Advocate (OCA) witness Roger D. Colton[1] concerning his recommended increase to UGI Utilities, Inc. – Gas Division's (UGI or Company)

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[1] OCA Statement No. 4 (Corrected), pp. 4-43.

Low Income Usage Reduction Program (LIURP) budget by $524,450;[2] (2) Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA) witness Harry S. Geller[3] concerning his recommended $352,008 increase to the Company's LIURP budget;[4] and (3) the Commission on Economic Opportunity (CEO) witness Eugene M. Brady[5] concerning his recommended $750,000 increase to the Company's LIURP budget.[6]

<u>RESPONSE TO OCA WITNESS ROGER D. COLTON</u>

Q. SUMMARIZE OCA WITNESS ROGER D. COLTON'S TESTIMONY REGARDING UGI'S LIURP BUDGET.

A. Mr. Colton recommended the Company's LIURP include a new incremental component to provide investments to confirmed low-income customers as part of the process of converting those customers to natural gas and resulting in an increase of $524,450 to the Company's LIURP budget.[7]

Q. WHAT IS THE BASIS FOR MR. COLTON'S RECOMMENDATION?

A. Mr. Colton opines that if UGI redirected a portion of its existing LIURP budget to serving gas conversion customers it would result in no net gain.[8] He calculates his recommended addition to the Company's LIURP budget using the 85 confirmed low-income gas conversions in 2021 and the calculated 2019 average UGI LIURP cost per

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2 OCA Statement No. 4 (Corrected), p. 21.
3 CAUSE-PA Statement No. 1, pp. 26-35.
4 CAUSE-PA Statement No. 1, p. 29.
5 CEO Statement No. 1, pp. 7-12.
6 CEO Statement No. 1, p. 8.
7 OCA Statement No. 4 (Corrected), p. 21.
8 OCA Statement No. 4 (Corrected), p. 21.

job of $6,170[9] producing his recommended increase of $524,450 to the Company's current LIURP budget.

Q. DO YOU AGREE WITH MR. COLTON'S RECOMMENDATION?

A. No. While Mr. Colton's recommendation is well-intentioned, it is inappropriate to consider such a significant increase in the LIURP budget in this base rate case proceeding.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that no increase to the budgeted LIURP amount be allowed.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. In response to CAUSE-PA-I-14, UGI has shown it was unable to exhaust its LIURP budget in the four most recent historic years other than exhausting it one time for the North District in 2018.[10] Additionally, Mr. Colton does not provide adequate support for how this incremental component ensures UGI will exhaust its existing LIURP budgeted funds.

<u>RESPONSE TO CAUSE-PA WITNESS HARRY GELLER</u>

Q. SUMMARIZE MR. GELLER'S TESTIMONY CONCERNING UGI'S LIURP BUDGET.

A. First, Mr. Geller asserts that UGI's LIURP is not operating at a rate sufficient to

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9 OCA Statement No. 4 (Corrected), pp. 20-21.
10 I&E Exhibit No. 1-R, Schedule 1.

fulfill the estimated need for comprehensive usage reduction services within a reasonable amount of time, citing UGI's most recent LIURP needs assessment results of 25 years to serve estimated need in UGI's former South District and 40 years to serve estimated need in UGI's former North District.[11] Additionally, he acknowledges UGI has failed to exhaust its existing LIURP budget.[12] In response to the aforementioned issues, he recommends UGI reduce its LIURP minimum usage threshold for households at or below 150% federal poverty level[13] and he recommends UGI increase its annual LIURP budget by a percentage equal to or greater than the average residential bill impact of any approved residential rate increase.[14] His recommendation results in an increase of $352,008 to the Company's current total LIURP budget of $3,705,350.[15]

Q. DO YOU AGREE WITH MR. GELLER THAT THE COMPANY SHOULD INCREASE ITS LIURP BUDGET BY $352,008 IN THIS PROCEEDING?

A. No, in part. First, I accept Mr. Geller's recommendation that UGI should continue its 2020 LIURP program year modification which lowered its LIURP minimum usage threshold to reflect the average usage of residential customers for customers at or below 150% of the Federal Poverty Level[16] to provide increased opportunity for UGI to exhaust its LIURP budgeted funds. Secondly, there is an error in Mr. Geller's calculation of the proposed LIURP budget increase which I will address next.

[11] CAUSE-PA Statement No. 1, p. 26.
[12] CAUSE-PA Statement No. 1, p. 27.
[13] CAUSE-PA Statement No. 1, p. 27.
[14] CAUSE-PA Statement No. 1, p. 27.
[15] CAUSE-PA Statement No. 1, p. 29.
[16] CAUSE-PA Statement No. 1, p. 28.

Finally, while his recommendation is well-intentioned, it is inappropriate to consider such an increase in the LIURP budget in this base rate proceeding.

Q. PLEASE ADDRESS MR. GELLER'S CALCULATION ERROR RELATED TO THE COMPANY'S LIURP BUDGET.

A. Mr. Geller cites UGI's response to CAUSE-PA IV-3 as the source of the Company's current total LIURP budget, stating a total of $3,705,350.[17] However, the resulting sum of the three district values provided in response to CAUSE-PA IV-3 is correctly calculated as $3,714,350 ($1,641,100 + $1,363,050 + $710,200).[18] Based on this correction, Mr. Geller's resulting recommended LIURP budget increase based on the residential rate increase percentage of 9.5%[19] would be $352,863 ($3,714,350 x 0.095).

Q. WHAT DO YOU RECOMMEND?

A. Even with the corrected calculation, Mr. Geller's recommendation should be denied and no change to the budget amount be allowed. As mentioned above, I accept Mr. Geller's suggestion that UGI should continue its 2020 LIURP program year modification which lowered its LIURP minimum usage threshold to reflect the average usage for residential customers at or below 150% of the Federal Poverty Level potentially providing increased opportunities for LIURP funds to be utilized.

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[17] CAUSE-PA Statement No. 1, p. 29.
[18] I&E Exhibit No. 1-R, Schedule 2.
[19] CAUSE-PA Statement No. 1, p. 29, line 11.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Mr. Geller admits that UGI has historically underspent its LIURP budget in each of the aforementioned former districts as evidenced by over $1 million unspent LIURP funds in 2021.[20] In essence he acknowledges UGI has failed to exhaust its existing LIURP budget.[21] This is visible by UGI's unused LIURP budgeted funds totaling $497,576 ($530,531 -$32,955)[22] in 2018; $891,529 ($753,712 + $137,547)[23] in 2019; $2,736,866 ($1,497,368 + $884,099 + $355,399)[24] in 2020; and $1,010,389 ($354,796 + $490,140 + $165,453) in 2021.[25] Given that UGI has not historically spent is LIURP funds and that Mr. Geller provides no support that UGI would be able to exhaust an increased LIURP budget, his recommendation should be denied.

<u>RESPONSE TO CEO WITNESS EUGENE BRADY</u>

Q. SUMMARIZE MR. BRADY'S TESTIMONY CONCERNING UGI'S LIURP BUDGET.

A. Mr. Brady states the Company estimates at the current funding level it would take 25 years to meet the LIURP need of the South District and 40 years to meet the LIURP need of the North District. In response, he recommends the annual funding for LIURP be increased by $750,000.[26]

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20 I&E Exhibit No. 1-R, Schedule 1.
21 CAUSE-PA Statement No. 1, p. 27.
22 I&E Exhibit No. 1-R, Schedule 1.
23 I&E Exhibit No. 1-R, Schedule 1.
24 I&E Exhibit No. 1-R, Schedule 1.
25 I&E Exhibit No. 1-R, Schedule 1.
26 CEO Statement No. 1, p. 8.

Q. WHAT IS THE BASIS FOR MR. BRADY'S RECOMMENDATION?

A. Mr. Brady refers to the Company's needs assessment stating there are approximately 10,000 low-income customers in need for LIURP services in two of the three prior UGI gas districts. Next, he states the Company's plan is to complete 481 LIURP jobs per year across its service territory and opines a good target would be complete an additional 100 jobs per year across the Company's service territory. Using a rounded LIURP job cost of $7,500 per job, the result would be an overall increase of $750,000 in additional funding required to complete the additional 100 LIURP jobs.

Q. DO YOU AGREE WITH MR. BRADY'S RECOMMENDATION?

A. No.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED DISALLOWANCE OF MR. BRADY'S PROPOSAL?

A. While Mr. Brady's recommendation is well-intentioned, it is inappropriate to consider increasing the LIURP budget in the instant proceeding. The Company has shown that it is unable to exhaust the existing budget,[27] and Mr. Brady has not provided support indicating that the Company would be able to utilize the increased amount.

Q. DO YOU HAVE ANY ADDITIONAL OVERALL COMMENTS REGARDING YOUR RECOMMENDATION TO DENY THESE PROGRAM INCREASES IN THIS PROCEEDING?

A. Yes. While my positions to the three witnesses above have specifically related to the

[27] I&E Exhibit No. 1-R, Schedule 1.

witnesses' failure to provide support for UGI's ability to utilize the additional funding, it is important to note that these program costs are directly assessed to other ratepayers. In the current economic climate with natural gas commodity costs climbing and overall inflation costing consumers substantially more in day-to-day necessities, implementing increases to these programs with no certainty of the Company's ability to utilize these additional funds is unreasonable. Furthermore, the ongoing supply chain and workforce issues may impede the Company's ability to utilize even the currently designated LIURP budget. From both perspectives, I find it unreasonable to impose additional costs to other ratepayers for this program in this proceeding.

RECENT COMMISSION ORDERS

Q. ARE THERE ANY RECENT COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATIONS AS EXPLAINED ABOVE?

A. In the recent PECO Energy Company – Gas Division proceeding the Commission did not consider CAUSE-PA's proposals relating to CAP and other universal service program issues within the context of the base rate proceeding because they would be more properly considered in its USECP proceeding.[28] The Commission referenced last year's Columbia Gas of Pennsylvania, Inc. (Columbia Gas) proceeding[29] in which it concluded, "that energy burdens should not be considered separately from other parts of the Company's CAP and universal service programs but should be considered

[28] *PA PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, pp. 195-196 (Order Entered June 22, 2021).

[29] *PA PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835 (Order Entered February 19, 2021).

as part of the Company's entire universal service plan, including the need for changes and associated costs."[30] It should be noted that in last year's Columbia Gas proceeding the Commission rejected a similar proposal related to the Health and Safety Pilot Program from CAUSE-PA.[31] In that proceeding the Commission agreed with the Administrative Law Judge's recommended decision denying any change to the pilot program until its effectiveness can be evaluated.[32]

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[30] *PA PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, p. 195 (Order Entered June 22, 2021).

[31] *PA PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, pp. 160-161 and 173-174 (Order Entered February 19, 2021).

[32] *PA. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, p. 174 (Order Entered February 19, 2021).

I&E Statement No. 1-SR
Witness: Zachari Walker

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Surrebuttal Testimony

of

Zachari Walker

Bureau of Investigation and Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

TAXES

LOW-INCOME USAGE REDUCTION PROGRAM

CASH WORKING CAPITAL

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zachari Walker, and my business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME ZACHARI WALKER WHO SUBMITTED I&E STATEMENT NO. 1, I&E EXHIBIT NO. 1, I&E STATEMENT NO. 1-R, AND I&E EXHIBIT NO. 1-R?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) witnesses Christopher R. Brown (UGI Gas Statement No. 1-R), Tracy A. Hazenstab (UGI Gas Statement No. 2-R), Vivian K. Ressler (UGI Gas Statement No. 3-R, and Daniel V. Adamo (UGI Gas Statement No. 12-R). Additionally, I respond to the rebuttal testimony of the Coalition for Affordable Utility Services and Energy Efficiency in

Pennsylvania (CAUSE-PA) witness Harry Geller (CAUSE-PA Statement No. 1-R).

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN ACCOMPANYING EXHIBIT?

A. Yes. I&E Exhibit No. 1-SR contains schedules that support my surrebuttal testimony. Additionally, I refer to my direct testimony and its accompanying exhibit (I&E Statement No. 1 and I&E Exhibit No. 1) and my rebuttal testimony (I&E Statement No. 1-R) in this surrebuttal testimony.

<u>OPERATING AND MAINTENANCE EXPENSE ADJUSTMENTS</u>

Q. PLEASE SUMMARIZE THE COMPANY'S REQUESTED REVENUE INCREASE.

A. In rebuttal testimony, UGI Gas explained that it believed it could now justify an increase of $87,619,000[1] for the Fully Projected Future Test Year (FPFTY) ending September 30, 2023. However, because the notice to customers indicated UGI Gas was requesting an increase of $82.7 million, it would not be possible for the Company's revenue increase to exceed this amount. Therefore, the UGI Gas actual requested increase remains $82.7 million.

[1] UGI Gas Exhibit A – FFPTY REBUTTAL, Schedule D-2.

Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS AS CONTAINED IN THIS SURREBUTTAL TESTIMONY.

A. The following table summarizes my recommended adjustments to the Company's rebuttal position:

	UGI Gas Claim	I&E Recommended Allowance	I&E Adjustment
O&M Expenses:			
Employee Activity Costs	$588,226	$217,935	($370,291)
Advertising Expense	$1,901,541	$1,016,363	($885,178)
Membership Dues	$1,115,404	$930,926	($184,478)
Payroll Expense	$82,237,000	$80,929,432	($1,307,568)
Employee Benefits Expense	$22,021,935	$21,671,786	($350,149)
Total O&M Adjustments			**($3,097,664)**
Taxes:			
Payroll Taxes	$6,870,000	$6,760,818	($109,182)
Total Tax Adjustments			**($109,182)**
Rate Base:			
Cash Working Capital	$61,697,000	$60,684,000	($1,060,000)
Total Rate Base Adjustments			**($1,060,000)**

SUMMARY OF I&E OVERALL UPDATED POSITION

Q. WHAT IS I&E'S TOTAL UPDATED RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for UGI Gas is $1,101,304,000.[2] This recommended revenue requirement represents an increase of $25,923,000 to the I&E-adjusted present rate revenues of $1,075,381,000. This total

[2] This amount includes base customer charges, gas cost revenue and other operating revenues like the Company's filing format shown on UGI Gas Schedule A-1.

recommended allowance incorporates my adjustments made in this testimony to O&M expenses, taxes, and cash working capital (CWC), and those recommended adjustments made in the surrebuttal testimony of I&E witnesses Anthony Spadaccio,[3] Brian LaTorre,[4] Ethan Cline,[5] and Esyan Sakaya.[6]

An updated calculation of I&E's recommended revenue requirement is shown below:

UGI UTILITIES INC. - GAS DIVISION		**TABLE I**			
R-2021-3030218		**INCOME**	**SUMMARY**		
($ in Thousands)					
	9/30/23	INVESTIGATION & ENFORCEMENT			
	Proforma	[--]			
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	1,061,721	13,660	1,075,381	25,923	1,101,304
Deductions:					
O&M Expenses	689,057	2,750	691,807	427	692,234
Depreciation	124,782	-3,494	121,288		121,288
Taxes, Other	13,524	-109	13,415	0	13,415
Income Taxes:					
Current State	3,844	1,748	5,592	2,547	8,139
Current Federal	14,080	3,308	17,388	4,819	22,207
Deferred Taxes	20,732	0	20,732		20,732
ITC	-324	0	-324		-324
Total Deductions	865,695	4,203	869,898	7,793	877,691
Income Available	196,026	9,457	205,483	18,130	223,613
Measure of Value	3,176,596	-154,799	3,021,797	0	3,021,797
Rate of Return	6.17%		6.80%		7.40%

[3] I&E Statement No. 2-SR.
[4] I&E Statement No. 3-SR.
[5] I&E Statement No. 4-SR.
[6] I&E Statement No. 5-SR.

EMPLOYEE ACTIVITY COSTS

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR EMPLOYEE ACTIVITY COSTS.

A. I recommended an allowance of $217,935 or a reduction of $370,291 ($588,226 - $217,935) to the Company's claim.[7] This recommendation is based on the historic year 2019 level expense inflated to the FPFTY equivalent due to the 2019 data representing the most recent known and measurable data prior to the effects of the pandemic. Given that we are still in the midst of the pandemic, it is not possible to know how many employees would be willing to gather at an optional Company picnic; therefore, the Company's claim is not prudent.

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Vivian Ressler disagrees with my recommendation.

Q. SUMMARIZE MS. RESSLER'S RESPONSE.

A. Ms. Ressler cites UGI Gas witness Christopher R. Brown's direct testimony which states the Company has experienced an increase in voluntary turnover. She states that the labor market is tight, and the Company believes spending a modest amount of money on activities can increase employee job satisfaction and therein

[7] I&E Statement No. 1, pp. 5-7.

employee retention. Finally, she opines the investment is insignificant compared to the cost of recruiting and training replacement employees.[8]

Q. DO YOU AGREE WITH MS. RESSLER'S ASSERTIONS?

A. No.

Q. WHAT IS YOUR RESPONSE?

A. Ms. Ressler did not cite data to support her claim of cost savings, nor the Company's position on employee job satisfaction and employee retention deriving from Company-sponsored activities. Additionally, she did not provide data to support that at least a majority of UGI Gas employees would be willing to attend an optional Company picnic.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR EMPLOYEE ACTIVITY COSTS?

A. No. The Company has the burden of proof to provide adequate support that the expenses claimed are incurred for the provision of safe and reliable gas service. It is my opinion that adequate support was not provided regarding the cost of employee activity costs claimed. Therefore, I have no changes to my

[8] UGI Gas Statement No. 3-R, pp. 40-41.

recommended allowance of $217,935 or a reduction of $370,291 ($588,226 - $217,935) to the Company's claim.

<u>COVID-19 RELATED UNCOLLECTIBLE ACCOUNTS EXPENSE</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR COVID-19 RELATED UNCOLLECTIBLE ACCOUNTS EXPENSE.

A. I accepted UGI Gas' total deferral claim of $1,503,000 for the 2020 and 2021 excess COVID-19 related uncollectible accounts, as well as the 10-year amortization period as approved by the Commission as part of the settlement in the UGI Gas 2020 base rate proceeding. However, I recommended that the Company should not be allowed to continue recording a regulatory asset for ongoing COVID-19 related incremental uncollectible costs after the effective date of new rates for the instant proceeding. This recommendation is based on COVID-19 related uncollectible accounts expenses being included in the forward-looking routine uncollectible accounts expense. As a result, allowing the Company to continue deferring these costs past the effective date of new rates in this proceeding would allow for redundant recovery of the COVID-19 related uncollectible accounts since they are already built into the routine uncollectible accounts percentage for the FPFTY calculation.[9]

[9] I&E Statement No. 1, pp. 10-11.

Additionally, in the 2020 Joint Petition for Unopposed Settlement – UGI Gas et al., page 21, item 49, the Company agreed not to continue accumulating COVID-19 related costs beyond the effective date of new rates for the instant proceeding.

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Vivian Ressler disagrees with my recommendation.

Q. SUMMARIZE MS. RESSLER'S RESPONSE.

A. Ms. Ressler states the Company would not continue to recover incremental uncollectible expense above the existing $12.81 million cap after the implementation of new rates for the instant proceeding, but would defer, for future recovery, costs in excess of the uncollectible accounts amount included in the new rates of the instant proceeding. She contests the Company did not relinquish its right to request an extension to the period of time to continue accumulating and deferring costs above the normalized level until the effective date of the Company's next base rate filing. Additionally, she states the Company has continued to experience higher than normal delinquency rates on COVID-related payment arrangements citing customers on these arrangements continue to carry balances that are higher than they were prior to the Commission's March 13, 2020 Emergency Order. Next, she cites inflationary factors causing the commodity cost of gas to increase opining this will likely cause the Company to incur additional incremental expenses above those embedded in rates. Then, she explains the Company's plan to defer and amortize incremental uncollectible costs in detail which includes deferral of costs in excess of an updated uncollectible accounts expense amount of $18.0 million until the next base rate filing. Finally, she proposes the Company be allowed to recover for ratemaking purposes the previously mentioned excess costs over a three-year amortization period, without interest.[10]

Q. WHAT IS YOUR RESPONSE TO MS. RESSLER'S ASSERTIONS?

A. In the current COVID-19 climate higher uncollectible accounts expense is the new normal and will be so for an undetermined amount of time moving forward. Thus, it is important to reflect the higher percentage in routine uncollectible accounts (as the Company has done) and cease the continued deferral of the excess uncollectible accounts expense past the effective date of new rates in the instant proceeding. It should be noted that in future base rate cases, the routine uncollectible percentage will be developed based on an average of three years of historic data which ensures the Company will recover higher amounts on an ongoing basis if this trend for higher uncollectible accounts expense continues. Thus, there is no need for a continued deferral of differences.

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[10] UGI Gas Statement No.3-R, p. 59.

The statement in the previous base rate case Settlement Agreement as stated in my direct testimony[11] most assuredly does not include verbiage that allows the Company to continue to accumulate COVID-19 related costs beyond the effective date of new rates for the instant proceeding. In summary, the continued accumulation, deferral, and ultimately amortization of COVID-19 related costs should not continue past the effective date of new rates in the instant proceeding.

Furthermore, Ms. Ressler's reference to ongoing inflationary factors potentially causing future increased uncollectible accounts is outside of the scope of the COVID-19 permitted deferrals originally authorized by the Commission. There is no basis to allow the Company to accrue increases in uncollectible expenses resulting from ongoing economic conditions unrelated to the pandemic in a regulatory asset account as changes in the economy and customer reaction to those changes are part of the normal cost of doing business. As I mentioned previously, these transient changes will be covered in the changing uncollectible percentage embedded in rates in future base rate filings and, at some point, it is likely that the embedded rate may even exceed the uncollectible percentage the Company would experience in a subsequent rate year.

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[11] I&E Statement No. 1, pp. 11-12.

Q. IF THE COMMISSION DECIDES TO ALLOW CONTINUED DEFERRAL OF COVID-19 RELATED UNCOLLECTIBLE ACCOUNTS, IN THIS INSTANCE IN EXCESS OF THE $18 MILLION PER YEAR CLAIM, SHOULD THE REQUESTED THREE-YEAR AMORTIZATION PERIOD (WITHOUT INTEREST) BE GRANTED?

A. No. It is inappropriate to grant an amortization period for an unknown amount to begin amortization in a future proceeding for COVID-19 related uncollectible accounts in excess of the claimed $18 million amount. I agree, if the Commission approves the Company's request, the amortization should occur without interest; however, until the actual amount would become known and be verifiable, it is not appropriate to assign a recovery period. An immaterial amount may allow for a shorter recovery period, and to the contrast, a very large deferral might require a longer recovery period.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR COVID-19 RELATED UNCOLLECTIBLE ACCOUNTS EXPENSE?

A. No. I continue to recommend that the deferral of COVID-19 related uncollectible accounts expense be disallowed upon the effective date of new rates in the instant proceeding. I further clarify my position to include a recommended denial for the deferral of any increase in uncollectible expense that may occur unrelated to the COVID-19 pandemic, which it appears that the Company now wants to recover as well.

ADVERTISING EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR ADVERTISING EXPENSE.

A. I recommended an allowance of $1,016,363 or a reduction of $885,178 ($1,901,541 - $1,016,363) to the Company's advertising expense claim. This recommendation was based on images provided that merely promote the Company's image without promoting the benefits of domestic natural gas. Consequently, I recommended the other advertising programs in the amount of $885,178 be disallowed for ratemaking purposes as these programs are not necessary to ensure safe and reliable gas service.[12]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Vivian Ressler disagrees with my recommendation.

Q. SUMMARIZE MS. RESSLER'S RESPONSE.

A. Ms. Ressler states the images which solely depict the image of the Company's logo are not able to visually show the opportunities afforded to Company personnel as a benefit of the Company's sponsorships. She further states these opportunities allow Company personnel to raise awareness of natural gas as an option by developing relationships and discussing the benefits of natural gas with

[12] I&E Statement No. 1, p. 13.

non-affiliated attendees. Finally, she opines that these sponsorships are key to attracting additional customers which reduces the overall revenue requirement that is borne by each individual customer.[13]

Q. DO YOU AGREE WITH MS. RESSLER'S ASSERTIONS?

A. No.

Q. WHAT IS YOUR RESPONSE?

A. Ms. Ressler did not provide data supporting her assertion that additional customers would be obtained this way and would reduce the overall cost per customer, nor did she provide data showing how many additional customers are directly gained from these sponsorships.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR ADVERTISING EXPENSE?

A. No. The Company has the burden of proof to provide adequate support that the expenses claimed are incurred for the provision of safe and reliable gas service. As to the matter of advertising expense, the support is not adequate and thus I continue to recommend an allowance of $1,016,363 or a reduction of $885,178 ($1,901,541 - $1,016,363) to the Company's FPFTY advertising expense claim.

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[13] UGI Gas Statement No. 3-R, pp. 44-45.

<u>MEMBERSHIP DUES</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR MEMBERSHIP DUES.

A. I recommended the disallowance of claims for numerous organizations where the Company has not provided adequate support for the necessity of ensuring safe and reliable gas service resulting in a decrease of $153,998 to the Company's membership dues claim, or an allowance of $961,406 ($1,115,404 - $153,998).[14]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Vivian Ressler disagrees with my recommendation.

Q. SUMMARIZE MS. RESSLER'S RESPONSE.

A. First, Ms. Ressler stated that the Company misidentified the organization that uses the acronym "CREDC." Due to the nature of the organizations for which I recommended to disallowance in my direct testimony, she includes the additional $30,480 with my adjustment. She states she will address my proposed adjustment as if it were a total of $184,478 ($153,998 + $30,480).[15]

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14 I&E Statement No. 1, pp. 14-15.
15 UGI Gas Statement No. 3-R, pp. 49-50.

Q. DO YOU HAVE ANY CONCERNS WITH MS. RESSLER'S ASSUMPTION REGARDING YOUR PROPOSED ADJUSTMENT?

A. No. If the organization was properly identified, I agree that I would have included it in my recommended adjustment.

Q PLEASE CONTINUE SUMMARIZING MS. RESSLER'S RESPONSE.

A. Ms. Ressler states the membership in economic development corporations like the PA Chamber of Business & Industry and the PA Economy League allow the Company to grow its customer base. She explains these organizations work with large commercial companies who are making site selections and by being a member of these organizations, the Company can proactively work with these potential customers to promote the benefits of natural gas for their energy needs. She opines this can also lead to opportunities for the Company to encourage new industrial and commercial customers to select sites that are near existing gas mains. Finally, she opines without membership and active involvement in these organizations, the Company would miss out on potential commercial customer growth which would result in higher costs passed along to residential customers.[16]

Q. WHAT IS YOUR RESPONSE TO MS. RESSLER'S ASSERTION?

A. Ms. Ressler did not provide data to support the claim that additional industrial and

[16] UGI Gas Statement No. 3-R, p. 51.

commercial customers would result in a reduction of costs passed along to residential customers. Furthermore, the Company has not adequately supported this expense's necessity to ensure safe and reliable gas service to its existing customers. Therefore, expenses associated with the organizations mentioned in my direct testimony[17] and the Capital Region Economic Development Company ($30,480) should be disallowed.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR MEMBERSHIP DUES?

A. Yes. As corrected in the Company's rebuttal testimony,[18] I recommend the disallowance of an additional $30,480 from the Company's claim, which is directly attributed to the previously misidentified organization, Capital Region Economic Development Company. This misidentification resulted in a misinterpretation of the organization's necessity to ensure safe and reliable gas service. My updated recommendation is an allowance of $930,926 ($1,115,404 - $184,478), or a decrease of $184,478 ($153,998 + $30,480) to the Company's FPFTY membership dues claim.

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[17] I&E Statement No. 1, pp. 14-15.
[18] UGI Gas Statement No. 3-R, p. 49.

INTEREST ON CUSTOMER DEPOSITS

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR INTEREST ON CUSTOMER DEPOSITS.

A. I recommended an allowance of $648,000, or a reduction of $324,000 ($972,000 - $648,000) to the Company's claim.[19] My recommendation was based on the current interest rate for Title 72 taxes of 3% for 2021 and 2022 and thus resulted in my recommended allowance of $648,000 ($21,600,000[20] x 3.00%).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Tracy Hazenstab accepts my recommendation to use the current interest rate of 3.00% for Title 72 taxes to calculate the FPFTY expense claim for interest on customer deposits.[21]

Q. DID THE COMPANY MAKE ANY CHANGES TO ITS CLAIM FOR CUSTOMER DEPOSITS?

A. Yes. Per UGI Gas Exhibit A – FPFTY REBUTTAL, Schedule C-7, the Company's updated claim based on a 13-month period ended April 2022 results in an updated claim of $21,434,000 for customer deposits.

[19] I&E Statement No. 1, p. 16.
[20] UGI Gas Statement No. 2, p. 21.
[21] UGI Gas Statement No. 2-R, p. 12.

Q. DID THE COMPANY CARRY THIS THROUGH IN ITS CALCULATION FOR THE UPDATED CLAIM FOR INTEREST ON CUSTOMER DEPOSITS?

A. No. However, the difference would be immaterial (approximately $5,000), and I am not arguing this point for that reason.

Q. WHAT IS THE COMPANY'S UPDATED CLAIM?

A. The Company's updated claim is $648,000 ($21,600,000[22] x 3.00%)[23] based on the original claim for customer deposits multiplied by my recommended 3.00% rate.

<u>PAYROLL EXPENSE</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR PAYROLL EXPENSE.

A. I recommended an allowance of $80,677,324, or a reduction of $2,251,676 ($82,929.000 - $80,677,324) to the Company's FPFTY payroll expense claim. This recommendation was based on an employee vacancy adjustment, produced by averaging fiscal year 2019, 2020, and 2021 historic vacancy rates, for unfilled positions included in the Company's claim using a vacancy rate of 2.74% to determine 47 vacant positions based on the average.[24] Finally, I multiplied the

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22 UGI Gas Statement No. 2, p. 21.
23 UGI Gas Exhibit A – FPFTY REBUTTAL, Schedule D-15.
24 I&E Statement No. 1, pp. 18-20.

average annual payroll of $47,908 to determine my recommended adjustment of $2,251,676.[25]

This was necessary because it is unreasonable to assume that 100% full staffing of all budgeted positions during the FPFTY.[26] Additionally, I noted that due to the COVID-19 pandemic, the Company may continue to face challenges keeping all positions filled and that there will always be a certain number of normal vacancies due to retirements, resignations, transfers, etc., on a day-to-day operating basis and that there will always be search and placement time in filling such vacancies.[27] Removing this savings from base rates is appropriate to avoid an unreasonable impact to ratepayers.

Q. DID THE COMPANY MAKE ANY CHANGES TO ITS CLAIM?

A. Yes. The Company updated its claim in rebuttal testimony.

Q. WHAT IS THE COMPANY'S UPDATED CLAIM?

A. UGI Gas updated its FPFTY payroll expense claim from $82,929,000 to $82,237,000.[28]

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25 I&E Statement No. 1, p. 19.
26 I&E Statement No. 1, p. 19.
27 I&E Statement No. 1, p. 20.
28 UGI Gas Exhibit A – FPFTY REBUTTAL, Sch. D-7, p. 1.

Q. WHAT WAS THE BASIS FOR THE COMPANY'S UPDATED CLAIM?

A. Ms. Hazenstab states the Company accepts OCA witness Mugrace's adjustment of $779,368 to reduce payroll expense for 17 speculative positions that are not yet filled.[29]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Tracy Hazenstab disagrees with my recommendation.

Q. SUMMARIZE MS. HAZENSTAB'S RESPONSE.

A. Ms. Hazenstab criticizes my adjustment opining it is biased due to COVID-19 impacting the Company's ability to hire new employees in fiscal year 2020 (FY20). Finally, she suggests removing FY20 which would lower the vacancy rate down to 1.59%.[30]

Q. WHAT IS YOUR RESPONSE TO MS. HAZENSTAB'S ASSERTION?

A. I am willing to accept Ms. Hazenstab's assertion that 2020 did heavily weight the average vacancy rate; however, upon further review it appears the reason is due to the unordinary increase in budgeted positions beginning in January 2020.[31] Due to the anomaly of budgeted positions in fiscal year 2020 and the extraordinary hiring circumstances as evidenced in the actual employees the Company held during this

[29] UGI Gas Statement No. 2-R, p. 13.
[30] UGI Gas Statement No. 2-R, pp. 13-14.
[31] I&E Exhibit No. 1, Schedule 11, p. 3.

period, I will accept the suggestion to lower the vacancy rate to 1.59% by removing the inconsistent data.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR PAYROLL EXPENSE?

A. Yes. I agree with the Company's acceptance of OCA's recommendation to eliminate 17 unfilled, speculative positions from the FPFTY; however, I continue to recommend a modified vacancy adjustment to the Company's updated claim. I am updating my recommendation with the FY20 data removed resulting in an average employee vacancy rate of 1.59% [(2.63% + 0.54%) ÷ 2]. My updated recommendation reflects a reduction of $1,307,568 ($82,237,000 x 1.59%) to the Company's updated FPFTY payroll expense claim, or an allowance of $80,929,432 ($82,237,000 - $1,307,568).

This adjustment continues to be necessary given there will still be a routine level of ongoing vacancies to the adjusted payroll claim as discussed above and in my direct testimony even after the removal of 17 speculative FPFTY positions.

<u>**EMPLOYEE BENEFITS**</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR EMPLOYEE BENEFITS.

A. I recommended an allowance of $21,510,994, or a reduction of $606,000 to the Company's FPFTY employee benefits claim based on an employee vacancy adjustment to payroll expense of 2.74%. The 2.74% vacancy rate was applied to the Company's employee benefits claim.[32]

Q. DID THE COMPANY MAKE ANY CHANGES TO ITS CLAIM?

A. Yes.

Q. WHAT IS THE COMPANY'S UPDATED CLAIM?

A. As calculated based on the response to I&E-RE-32,[33] the Company's updated claim is $22,021,935 ($22,117,000 - $95,065[34]) when accounting for the acceptance of OCA witness Mr. Mugrace's adjustment.

Q. DID ANY WITNESSES ADDRESS YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Tracy Hazenstab disagrees with my recommendation and UGI Gas witness Vivian Ressler addresses an update to the Company's claim.

Q. SUMMARIZE MS. HAZENSTAB'S RESPONSE.

A. Ms. Hazenstab states the Company disagrees with my recommendation as it is derivative of my proposed adjustment to the projected FPFTY employee headcount. Additionally, she points to Ms. Ressler's testimony which addresses a

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[32] I&E Statement No. 1, pp. 21-22.
[33] I&E Exhibit No. 1, Sch. 13, p. 2.
[34] UGI Gas Statement No. 2-R, p. 14.

related three-year normalization recommendation made by OCA witness Mr. Mugrace.[35]

Q. SUMMARIZE MS. RESSLER'S REBUTTAL TESTIMONY REGARDING EMPLOYEE BENEFITS.

A. Ms. Ressler addresses OCA witness Mr. Mugrace's recommendation to normalize medical and dental costs over a three-year period from 2021-2023. She asserts his reasons do not support that his adjustment is reasonable or appropriate; however, she cites his overall headcount reduction and states the Company has reflected the reduction in its adjustment to employee benefits expense – medical and dental costs. The adjustment results in a reduction of $95,065 to the Company's pre-rebuttal FPFTY employee benefits claim.[36]

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. I am updating my recommendation to reflect my updated payroll vacancy adjustment by applying the 1.59% vacancy rate to the Company's updated claim for employee benefits. This results in a reduction of $350,149 ($22,021,935 x 1.59%) to the Company's updated claim or an allowance of $21,671,786 ($22,021,935 - $350,149).

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[35] UGI Gas Statement No. 2-R, p. 14 and UGI Gas Statement No. 3-R, pp. 37-39.
[36] UGI Gas Statement No. 3-R, pp. 37-39.

PAYROLL TAXES

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR PAYROLL TAXES.

A. I recommended an allowance of $6,738,985, or a reduction of $188,015 ($6,927,000 - $6,738,985) to the Company's FPFTY claim based on the total payroll expense adjustment of $2,251,676 and calculated by applying the Company's payroll tax rate of 8.35%.[37]

Q. DID THE COMPANY UPDATE ITS CLAIM?

A. Yes.

Q. WHAT IS THE COMPANY'S UPDATED CLAIM?

A. The Company's updated claim for payroll tax expense is $6,870,000. This is due to the Company's acceptance of OCA witness Mr. Mugrace's proposed elimination of 17 speculative FPFTY positions, which produces a corresponding payroll tax expense reduction of $57,000.[38]

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. No. However, since UGI Gas witness Tracy Hazenstab disagrees with my payroll

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[37] I&E Statement No. 1, pp. 22-23.
[38] UGI Gas Statement No. 2-R, p. 15.

expense recommendation, it is safe to assume she disagrees with my payroll tax expense recommendation.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. My updated recommendation for payroll tax expense is calculated by applying the Company's payroll tax rate of 8.35% to my updated payroll expense adjustment of $1,307,568. This produces an updated recommended reduction of $109,182 ($1,307,568 x 0.0835) to the Company's updated claim of $6,870,000, or an updated allowance of $6,760,818 ($6,870,000 - $109,182).

PROPOSED ADDITIONAL PAYROLL EXPENSE

Q. DID THE COMPANY ADDRESS ADDITIONAL EXPENSES RELATED TO PAYROLL COSTS?

A. Yes. UGI Gas witness Christopher R. Brown mentioned that since the original base rate filing was assembled the Company has decided to prepare an enhanced merit program to be rolled out later this year in response to increased turnover and increased inflation.[39]

Q. WHAT IS THE PROJECTED COST OF THIS PROGRAM?

A. UGI Gas witness Brown indicates an additional two percent pay increase to non-

[39] UGI Gas Statement No. 1-R, pp. 4-5.

union personnel would result in an additional $960,000 in FPFTY operating expense after the Company's acceptance of OCA's adjustment for the removal of 17 positions.[40]

Q. IS THE COMPANY CLAIMING AN ADDITIONAL $960,000 IN ITS FPFTY PAYROLL CLAIM?

A. No. However, the Company is asking the Commission to consider adding an additional $960,000 for merit increases to offset any further downward adjustments to payroll in this proceeding.[41]

Q. DO YOU AGREE THAT THE COMPANY SHOULD BE ALLOWED TO INTRODUCE A NEW PAYROLL PROPOSAL IN REBUTTAL TESTIMONY?

A. No. In its filing, the Company already made a claim for a compensation benchmarking adjustment relying on data provided by the American Gas Association.[42] Those planned adjustments increased the Company's FPFTY claim by $1.2 million,[43] and I did not argue against that claim. I disagree that it should be necessary to increase merit pay increases from three percent to five percent in the FPFTY given that salaries are already being adjusted in response to this

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40 UGI Gas Statement No. 1-R, p. 5.
41 UGI Gas Statement No. 1-R, pp. 5-6.
42 UGI Gas Statement No. 1, p. 27.
43 UGI Gas Exhibit A – Fully Projected, Schedule D-9.

industry study. To do both would be imprudent and burdensome to ratepayers. Thus, I disagree with Mr. Brown that the Commission should consider tacking on additional non-union pay increases to offset any further downward adjustments in this proceeding. Awarding extra pay increases to non-union workers on top of adjusted salaries would be very inappropriate given that UGI Gas plans to make base rate filings on a regular frequency and has not even allowed itself to view the impact of the upward pay adjustments already claimed.

CASH WORKING CAPITAL

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR CWC.

A. I recommended an allowance of $61,313,000, or a reduction of $835,000 ($62,148,000 - $61,313,000) to the Company's claim.[44] My recommendation includes modification of the Company's claim based on my recommended adjustments to O&M expenses as discussed in I&E's direct testimony.

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Tracy Hazenstab disagrees with my CWC recommendation based on the Company's disagreement with my recommended adjustments to individual O&M expenses.

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[44] I&E Statement No. 1, p. 24.

Q. WHAT IS THE COMPANY'S UPDATED CWC CLAIM?

A. UGI Gas updated its FPFTY CWC claim from $62,148,000 to $61,697,000.[45]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No. However, I have an update to my recommendation for CWC. As stated in my direct testimony, all O&M expense adjustments that are cash-based expense claims are included when determining the Company's overall CWC requirement. Therefore, CWC was adjusted to reflect these recommended adjustments. To reflect the I&E recommended adjustments, I modified the Company's electronic CWC file as shown on UGI Gas Book V, Schedule C-4, pp. 1, 2, 3, and 7, for each recommended adjustment.

Q. SUMMARIZE WHERE EACH OF THE I&E RECOMMENDED O&M EXPENSE ADJUSTMENTS ARE REFLECTED IN THE CWC COMPUTATION.

A. **Expense Lag Days - Payroll:**

I recommended a payroll expense adjustment of ($1,307,568) in the Expense Lag - Payroll, which is reflected as reduction to line 3 of the Company's Exhibit A – Fully Projected, Schedule C-4, p. 2 as shown in I&E modified Schedule C-4.[46]

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[45] UGI Gas Statement No. 2-R, p. 16.

[46] I&E Exhibit No. 1-SR, Schedule 1, p. 2, line 3.

Expense Lag Days – Purchased Gas Costs:

Mr. Cline recommended a purchased gas expense increase of $7,221,028, which is reflected as an addition in the FPFTY purchased gas costs of $404,384,000 ($397,163,000 + $7,221,028) in the Purchased Gas Costs Expense Lag Days calculation.[47]

Expense Lag Days – Other Expenses:

Mr. LaTorre and I recommended the following expense adjustments in the Expense Lag Days - Other Expenses as an overall decrease of $3,273,252 of the Company's Exhibit A – Fully Projected, Schedule C-4, p. 2 as shown in I&E modified Schedule C-4:[48]

Other Expenses	Reduction
Employee Activity Costs	$370,291
Advertising Expense	$885,178
Membership Dues	$184,478
Rate Case Expense	$422,000
Environmental Remediation Expense	$930,800
OSHA/Emergency Temporary Standard Compliance Costs	$21,174
Employee Benefits Expense	$350,149
Payroll Taxes	$109,182
Total	**$3,273,252**

47 I&E Exhibit No. 1-SR, Schedule 1, p. 2, line 4.
48 I&E Exhibit No. 1-SR, Schedule 1, p. 2, line 5.

<u>Revenue Lag Calculations:</u>

Mr. Cline recommended an adjustment to increase present rate revenue by $13,659,652 and is reflected as an addition in the total account receivable amount of $1,304,898,652 ($1,327,239,000 + $13,659,652) and in the total sales revenue of $857,931,652 ($844,272,000 + $13,659,652) in the Revenue Lag calculation.[49]

<u>Interest Payment Lag Calculations:</u>

Mr. Sakaya recommended an adjustment to rate base of $153,739,000 ($137,539,000 + $16,200,000), which is reflected as a reduction to rate base resulting in an updated total of $3,022,857,000 ($3,176,596,000 - $153,739,000) in the Interest Payments Lag calculation.[50]

Q. BASED ON THE ABOVE TESTIMONY, WHAT IS YOUR UPDATED RECOMMENDED ALLOWANCE FOR CWC?

A. Based on reflecting all of I&E's recommended adjustments as discussed above, my updated recommendation for CWC is an allowance of $60,637,000, or a reduction of $1,060,000 ($61,697,000 - $60,637,000) to the Company's updated claim.[51]

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[49] I&E Exhibit No. 1-SR, Schedule 1, p. 3, lines 15 and 18.
[50] I&E Exhibit No. 1-SR, Schedule 1, p. 4, line 1.
[51] I&E Exhibit No. 1-SR, Schedule 1, p. 1, line 5.

Q. DOES YOUR RECOMMENDED ALLOWANCE REPRESENT A FINAL RECOMMENDED ALLOWANCE FOR CWC?

A. No. All adjustments to the Company's claims for revenues, expenses, taxes, and rate base must be consistently brought together in the Administrative Law Judge's Recommended Decision and again in the Commission's Final Order. This process, which is known as iteration, effectively prevents the determination of a precise calculation until such time as all adjustments have been made to the Company's claim.

<u>LOW INCOME USAGE REDUCTION PROGRAM (LIURP)</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN REBUTTAL TESTIMONY FOR LIURP.

A. In my rebuttal testimony, I stated the recommendations of CAUSE-PA witness Harry S. Geller, OCA witness Roger D. Colton, and CEO witness Eugene M. Brady which advocated to increase the Company's LIURP budget should be denied because the Company has been unable to exhaust its budget as it stands, and the witnesses have failed to show how the Company's would utilize the additional funding.[52]

[52] I&E Statement No. 1-R.

Q. DID ANY WITNESSES' REBUTTAL TESTIMONY CONFLICT WITH YOUR RECOMMENDATION?

A. Yes. CAUSE-PA witness Harry S Geller's rebuttal testimony conflicts with my recommendation.

Q. SUMMARIZE MR. GELLER'S RESPONSE.

A. Mr. Geller states the Company's LIURP budget should be increased in line with OCA witness Mr. Colton's recommendation which would expand UGI Gas' LIURP budget by $1.425 million and include incremental LIURP investments of $524,450.[53]

Q. DID ANY WITNESS' RECOMMENDATION ALIGN WITH YOUR REBUTTAL TESTIMONY?

A. Yes. UGI Gas witness Daniel V. Adamo puts forth rebuttal testimony in line with mine on this topic.

Q. SUMMARIZE MR. ADAMO'S RESPONSE AS IT RELATES TO YOUR RECOMMENDATION.

A. Mr. Adamo states that the LIURP budget should be addressed in the Company's next universal service proceeding where a needs assessment would be completed

[53] CAUSE-PA Statement No. 1-R, pp. 6-7.

to help determine the appropriate budget level, and he states that Mr. Colton is making a recommendation on an annual LIURP spending level of $2.1 million but the Company already has an approved budget of approximately $3.7 million.[54] Similarly, he disagrees with Mr. Geller's and Mr. Brady's recommendations for LIURP.[55]

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR UGI GAS' LIURP BUDGET?

A. No. I continue to recommend any increase to the annual funding for LIURP be disallowed.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

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[54] UGI Gas Statement No. 12-R, p. 30.
[55] UGI Gas Statement No. 12-R, pp. 31-32.

I&E Statement No. 2
Witness: Anthony Spadaccio

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Direct Testimony

of

Anthony Spadaccio, CRRA

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Anthony Spadaccio. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL EXPERIENCE?

A. My educational and professional experience is set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the utility company, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to address the rate of return, including capital structure, cost of long-term debt, the cost of equity, and the overall fair rate of return for UGI Utilities, Inc. – Gas Division (UGI Gas or Company) for the fully projected future test year (FPFTY) ending September 30, 2023.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules that support my direct testimony.

<u>BACKGROUND</u>

Q. WHAT IS THE GENERAL DEFINITION OF RATE OF RETURN IN THE CONTEXT OF A RATE CASE?

A. Rate of return is one of the components of the revenue requirement formula. Rate of return is the amount of revenue an investment generates in the form of net income and is usually expressed as a percentage of the amount of capital invested over a given period of time.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula used in base rate cases is as follows:

$$RR = E + D + T + (RB \times ROR)$$

Where:

RR	=	Revenue Requirement
E	=	Operating Expenses
D	=	Depreciation Expense
T	=	Taxes
RB	=	Rate Base
ROR	=	Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that percentage is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the Company's rate base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one that will allow the utility an opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect.

The *Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (1923), and the *Federal Power Commission et al v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) cases set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

1. A utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.
2. A utility is entitled to a return level reasonably sufficient to assure financial soundness.
3. A utility is entitled to a return sufficient to maintain and support its credit and raise necessary capital.
4. A fair return can change (increase or decrease) along with economic conditions and capital markets.

Q. EXPLAIN HOW THE OVERALL RATE OF RETURN IS TRADITIONALLY CALCULATED IN BASE RATE PROCEEDINGS.

A. In base rate proceedings, the overall rate of return is traditionally calculated using the weighted average cost of capital method. To calculate the weighted average cost of capital, a company's capital structure must first be determined by comparing the percentage of each capitalization component, which has financed rate base, to total capital. Next, the effective cost rate of each capital structure component must be determined. The historical component of the cost rate of debt can be computed accurately, and any future debt issuances are based on estimates. The cost rate of common equity is not fixed and is more difficult to measure. Because of this difficulty, a proxy group is used as discussed later in this testimony. Next, each capital structure component percentage is multiplied by its corresponding effective cost rate to determine the weighted capital component cost rate. The table in the *"I&E Position"* section below demonstrates the interaction of each capital structure component and its corresponding effective cost rate. Finally, the sum of the weighted cost rates produces the overall rate of return. This overall rate of return is multiplied by the rate base to determine the return portion of a company's revenue requirement.

COMPANY'S RATE OF RETURN CLAIM

Q. WHO IS THE COMPANY'S RATE OF RETURN WITNESS IN THIS CASE?

A. Paul R. Moul is the primary witness addressing rate of return. Throughout his Direct Testimony (UGI Gas Statement No. 6), Mr. Moul provides his analysis for the claimed capital structure, long-term debt, and cost of common equity for UGI Gas.

Q. PLEASE SUMMARIZE MR. MOUL'S RECOMMENDATIONS FOR THE COMPANY'S RATE OF RETURN CLAIM.

A. Mr. Moul recommends the following rate of return for the Company based on its FPFTY ending September 30, 2023:[1]

UGI UTILITIES, INC. - GAS DIVISION Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
UGI Utilities, Inc. - Gas Division			
Long-Term Debt	44.88%	3.98%	1.79%
Common Equity	55.12%	11.20%	6.17%
Total	100.00%		7.96%

I&E POSITION

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION FOR THE COMPANY.

A. I recommend the following rate of return for the Company:[2]

I&E Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
UGI Utilities, Inc. - Gas Division			
Long-Term Debt	44.88%	3.98%	1.79%
Common Equity	55.12%	9.92%	5.47%
Total	100.00%		7.26%

[1] UGI Gas Exhibit B, Schedule 1.
[2] I&E Exhibit No. 2, Schedule 1.

<u>PROXY GROUP</u>

Q. WHAT IS A PROXY GROUP AS USED IN BASE RATE CASES?

A. A proxy group is a set of companies that have similar traits as compared to the subject utility. This group of companies acts as a benchmark for determining the subject utility's rate of return in a base rate case.

Q. WHAT ARE THE REASONS FOR USING A PROXY GROUP?

A. A proxy group's cost of equity is used as a benchmark to satisfy the long-established guideline of utility regulation that seeks to provide the subject utility with the opportunity to earn a return similar to that of enterprises with corresponding risks and uncertainties.

A proxy group is typically utilized since the use of data exclusively from one company may be less reliable. The lower reliability occurs because the data for one company may be subject to events that can cause short-term anomalies in the marketplace. The rate of return on common equity for a single company could become distorted in these circumstances and would therefore not be representative of similarly situated companies. Therefore, a proxy group has the effect of smoothing out potential anomalies associated with a single company.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR GAS UTILITY PROXY GROUP?

A. The criteria for my proxy group was designed to select companies that are representative of UGI Gas. I applied the following criteria to Value Line's "Natural Gas Utility" company group:

1. Fifty percent or more of the company's revenues must be generated from the regulated gas utility industry.

2. The company's stock must be publicly traded.

3. Investment information for the company must be available from more than one source, which includes Value Line.

4. The company must not be currently involved in an announced merger or the target of an acquisition.

5. The company must have four consecutive years of historic earnings data.

6. The company must be operating in a state that has a deregulated gas utility market.

Q. WHAT CRITERIA DID MR. MOUL USE IN SELECTING THE COMPANIES THAT FORMULATE HIS "GAS GROUP"?

A. Mr. Moul began with the gas utilities contained in Value Line's Investment Survey. From there, he eliminated one company, UGI Corp., due to its diversified businesses, which includes six reportable segments. These various business segments include propane, international LPG segments, natural gas utility, energy services, and electric generation. Beyond his rationale for excluding UGI Corp., Mr. Moul has not provided a list of criteria used to determine the remainder of his Gas Group other than that it is made up of the companies the Commission's Bureau of Technical Utility Services used to calculate the cost of equity in its Quarterly Earnings Reports approved on October 9, 2021.[3]

[3] UGI Gas Statement No. 6, p. 5, lines 4-18.

Q. WHAT PROXY GROUP DID YOU USE IN YOUR ANALYSIS?

A. I included the following seven companies in my proxy group:

Atmos Energy Corp.	ATO
Chesapeake Utilities	CPK
NiSource Inc.	NI
Northwest Natural Gas Co.	NWN
One Gas Inc.	OGS
South Jersey Industries Inc.	SJI
Spire Inc.	SR

Q. WHAT PROXY GROUP DID MR. MOUL USE IN HIS ANALYSIS?

A. Mr. Moul's Gas Group consists of the following nine companies:[4]

Atmos Energy Corp.	ATO
Chesapeake Utilities	CPK
New Jersey Resources Corp.	NJR
NiSource Inc.	NI
Northwest Natural Gas Co.	NWN
One Gas Inc.	OGS
South Jersey Industries Inc.	SJI
Southwest Gas Corp.	SWX
Spire Inc.	SR

Q. DO YOU AGREE WITH MR. MOUL'S GAS PROXY GROUP?

A. Not entirely. While Mr. Moul's Gas Group included all seven of the companies in my proxy group, I have excluded two of the companies he uses.

4 UGI Gas Exhibit B, Schedule 3, p. 2.

Q. PLEASE IDENTIFY THE TWO COMPANIES MR. MOUL HAS INCLUDED THAT YOU DO NOT AND EXPLAIN WHY YOU HAVE EXCLUDED THEM FROM YOUR PROXY GROUP.

A. The two companies Mr. Moul included in his Gas Group that I have excluded from my proxy group are New Jersey Resources Corp. and Southwest Gas Holdings, Inc. as these companies did not meet my first criterion that fifty percent or more of the company's revenues must be generated from the regulated gas utility industry. This is important because revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If less than fifty percent of revenues come from the regulated gas sector, the companies are not comparable to the subject utility as they do not provide a similar level of regulated business. Therefore, these companies should be removed from the proxy group.

<u>CAPITAL STRUCTURE</u>

Q. WHAT IS A CAPITAL STRUCTURE?

A. A capital structure represents how a firm has financed its rate base with different sources of funds. The primary sources of funding are long-term debt and common equity. A capital structure may also include preferred stock and/or short-term debt, although this is not the case for UGI Gas.

Q. WHAT IS THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. The Company's claimed capital structure is summarized in the table below:[5]

UGI Utilities, Inc. - Gas Division Capital Structure - September 30, 2023	
Long-Term Debt	44.88%
Common Equity	55.12%
Total	**100.00%**

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. Mr. Moul explains that UGI Utilities, Inc. raises its own long-term debt directly in the capital markets. He believes the consolidated capital structure ratios for UGI Utilities, Inc. should be used in determining the rate of return for each of its utility divisions because all operations of each the division are financed on a consolidated basis.[6]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE?

A. I recommend using the Company's claimed capital structure as presented in the table above.

[5] UGI Gas Statement No. 6, p. 21, ln. 22 through p. 22, ln. 4 and UGI Gas Exhibit B, Schedule 5.
[6] UGI Gas Statement No. 6, p. 20, lines 5-16.

Q. WHAT IS THE BASIS FOR YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. Although I believe a capital structure of 50% long-term debt and 50% common equity is optimal when trying to balance the financial integrity of a utility as well as trying to control costs to ratepayers, in this proceeding, I recommend using the Company's claimed capital structure as it falls within the range of my proxy group's 2020 (most recently available) capital structures. The most recent five-year average range contains individual company capital structure ratios from 27.88% to 55.48% long-term debt and 34.19% to 56.96% equity, with an overall five-year average of 41.48% long-term debt and 46.93% common equity.[7] UGI Gas only employs short-term debt to finance non-rate base items, which is why it has been excluded in this proceeding.

It is worth noting that the Company's equity ratio is well above the average and near the highest end of the proxy group's equity ratios. In fact, five of the seven companies in my proxy group have a capital structure wherein the equity ratio is less than 50%. This equity heavy capital structure must be recognized when considering UGI Gas' financial risk, as higher equity ratios generally correspond with lower financial risk as Mr. Moul himself concedes.[8]

For consideration when examining the Company's overall financial risk, the example below illustrates the cost savings to ratepayers if the Company were to employ a 50% long-term debt and 50% common equity capital structure in its cost of capital while

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[7] I&E Exhibit No. 2, Schedule 2.
[8] UGI Gas Statement No. 6, p. 17, lines 5-7.

maintaining its claimed return on equity and rate base:

Type of Capital	Ratio	Cost Rate	Weighted Cost
UGI UTILITIES, INC. - GAS DIVISION			
Summary of Cost of Capital			
AS FILED CAPITAL STRUCTURE			
Long-Term Debt	44.88%	3.98%	1.79%
Common Equity	55.12%	11.20%	6.17%
Total	100.00%		7.96%
50/50 OPTIMAL CAPITAL STRUCTURE			
Long-Term Debt	50.00%	3.98%	1.99%
Common Equity	50.00%	11.20%	5.60%
Total	100.00%		7.59%
Difference In The Overall Rate of Return (7.96% - 7.59% = 0.37%)			0.37%
Impact To Ratepayers (Claimed Rate Base* x Difference In The Overall Rate of Return) ($3,169,023,000 x .0037)			$11,725,385
Gross Revenue Conversion Fator**			1.429864
Total Impact To Ratepayers ($11,725,385 x 1.429864)			**$16,765,706**

*UGI Gas Exhibit A, Schedule A-1, ln. 9.
**UGI Gas Exhibit A, Schedule A-1, ln. 24.

In this example, if the Company were to employ a 50/50 capital structure, the cost savings to ratepayers would be $16,765,706. While I understand achieving and maintaining an exact 50/50 capital structure is not truly feasible, this example is intended to demonstrate UGI Gas's financial security as compared to its peers and prove that Mr. Moul's various "add-ons" to his cost of equity calculations are unnecessary.

COST OF LONG-TERM DEBT

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S COST RATE OF LONG-TERM DEBT?

A. I recommend using the Company's claimed long-term debt cost rate of 3.98% for the FPFTY.[9]

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S CLAIMED COST RATE OF LONG-TERM DEBT?

A. The Company's claimed cost rate of long-term debt is reasonable, as it is representative of the industry. It falls within my proxy group's implied long-term debt cost range of 1.96% to 4.58%, with an average implied long-term debt cost of 3.99%.[10] Additionally, the Company's forecasted cost of long-term debt has been gradually trending downward, which is beneficial to ratepayers; therefore, I recommend the claimed cost rate of long-term debt be used.

COST OF COMMON EQUITY

COMMON METHODS

Q. WHAT METHODS ARE COMMONLY PRESENTED BY UTILITIES IN DETERMINING THE COST OF COMMON EQUITY?

A. Four methods commonly presented to estimate the cost of common equity are the Discounted Cash Flow (DCF), the Capital Asset Pricing Model (CAPM), the Risk Premium (RP) Method, and the Comparable Earnings (CE) Method.

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[9] UGI Gas Statement No. 6, p. 23, ln. 25 through p. 24, ln. 1 and UGI Gas Exhibit B, Schedule 6, p. 3.
[10] I&E Exhibit No. 2, Schedule 3.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF METHOD?

A. The DCF method is the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The DCF method assumes that investors evaluate stocks in the traditional economic framework, which maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CAPM?

A. The CAPM describes the relationship of a stock's investment risk and its market rate of return. It identifies the rate of return investors expect so that it is comparable with returns of other stocks of similar risk. This method hypothesizes that the investor-required return on a company's stock is equal to the return on a "risk free" asset plus an equity premium reflecting the company's investment risk. In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk); and (2) market risk (systematic risk), which is measured by a firm's beta. The CAPM allows for investors to receive a return only for bearing systematic risk. Unsystematic risk is assumed to be diversified away, and therefore, does not earn a return.

Q. WHAT IS THE THEORETICAL BASIS FOR THE RP METHOD?

A. The theoretical basis for the RP method is a simplified version of the CAPM. The RP method's theory is that common stock is riskier than debt, thus, investors require a higher expected return on stocks than bonds. In the RP approach, the cost of equity is made up of the cost of debt and a risk premium. While the CAPM uses the market risk premium, it also directly measures the systematic risk of a company or proxy group through the use of beta. The RP method does not measure the specific risk of a company.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CE METHOD?

A. The CE method utilizes the concept of opportunity cost. This means that investors will likely dedicate their capital to the investment offering the highest return with similar risk to alternative investments. Unlike the DCF, CAPM, and the RP methods, the CE method is not market-based and relies upon historic accounting data. The most problematic issue with the CE method is determining what constitutes comparable companies.

Q. WHAT METHOD DO YOU RECOMMEND USING TO DETERMINE AN APPROPRIATE COST OF COMMON EQUITY FOR UGI GAS?

A. I recommend using the DCF method as the primary method to determine the cost of common equity. Additionally, I recommend using the results of the CAPM as a comparison to the DCF results. This is consistent with the methodology historically used by the Commission in base rate proceedings, but also as recently as 2017, 2018, 2020, and 2021.[11]

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[11] *Pa. PUC v. City of DuBois – Bureau of Water*; Docket No. R-2016-2554150 (Order Entered March 28, 2017). *See generally* Disposition of Cost Rate Models, pp. 96-97; *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Cost of Common Equity, p. 119; *Pa. PUC v. Wellsboro Electric Company;* Docket No. R-2019-3008208 (Order Entered April 29, 2020). *See generally* Disposition of Primary Methodology to Determine ROE, pp. 80-81; *Pa. PUC v. Citizens Electric Company of Lewisburg, PA;* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 91-92. *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.;* Docket No. R-2020-3018835 (Order Entered February 19, 2021). *See generally* Disposition of Cost of Common Equity, p. 131.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE DCF AND CAPM IN YOUR ANALYSIS.

A. I have used the DCF as the primary method for a variety of reasons. The DCF is appealing to investors since it is based upon the concept that the receipt of dividends in addition to expected appreciation is the total return requirement determined by the market.[12] The use of a growth rate and expected dividend yield are also strengths of the DCF, as this recognizes the time value of money and is forward-looking. The use of the utilities' own, or in this case the proxy group's, stock prices and growth rates directly in the calculation also causes the DCF to be industry and company specific. Therefore, the DCF method is superior for determining the rate of return for the current economic market because it measures the cost of equity directly.

I have included a CAPM analysis as a comparison because the CAPM and the DCF include inputs that allow the results to be specific to the utility industry, although the CAPM is far less responsive to changes in the industry than the DCF. The CAPM is based on the performance of U.S. Treasury bonds and the performance of the market as measured through the S&P 500 and is company-specific only through the use of beta. Beta reflects a stock's volatility relative to the overall market, thereby incorporating an industry-specific aspect to the CAPM, but only as a measure of how reactive the industry is compared to the market as a whole. Although changes in the utility industry are more likely to be accurately reflected in the DCF, which uses the companies' actual prices, dividends, and growth rates, I have included the results of my CAPM analysis because changes in the market, whether as a whole or specific to the utility industry, affect the

[12] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2010 Edition, p. 151.

outcome of each method in different ways. Although I have chosen to use the CAPM as a secondary method, it does have several disadvantages and should not be used as a primary method.

Q. EXPLAIN THE DISADVANTAGES OF THE CAPM.

A. The CAPM, and the RP method by virtue of its similarities to the CAPM, give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period in which the risk premiums were determined. This is because beta, which is the only company-specific variable in the CAPM model, measures the *historical* volatility of a stock compared to the *historical* overall market return. Reliance on historical values is especially problematic now given the recent impact of the COVID-19 pandemic on economic conditions. Although the CAPM and RP results can be useful to investors in making rational buy and sell decisions within their portfolios, the DCF method is the superior method for determining the rate of return for the current economic market and measuring the cost of equity directly. The CAPM and the RP methods are less reliable indicators because they measure the cost of equity indirectly and risk premiums vary depending on the debt and equity being compared. Also, regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or will be the same in the future.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, "Market Place; A Study Shakes Confidence in the Volatile-Stock

Theory," which appeared in the *New York Times* on February 18, 1992, summarized a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French.[13] Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory a stock with a higher beta should have a higher expected return. However, they found that the model did not do well in predicting actual returns and suggested the use of more elaborate multi-factor models.

A more recent article, "The Capital Asset Pricing Model: Theory and Evidence," which appeared in the *Journal of Economic Perspectives,* states that "the attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor - poor enough to invalidate the way it is used in applications."[14] As a result, I conclude that the CAPM's relevance to the investment decision making process does not carry over into the regulatory rate setting process.

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP METHOD FROM YOUR ANALYSIS.

A. The RP method is excluded because it is a simplified version of the CAPM and is subject to the same faults explained above. Most importantly, unlike the CAPM, the RP method does not recognize company-specific risk through beta.

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13 Berg, Eric N. "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory" *The New York Times*, 18 Feb 1992: *nytimes.com* Web. 23 Mar 2016.

14 Fama, Eugene F. and French, Kenneth R., "The Capital Asset Pricing Model: Theory and Evidence." *Journal of Economic Perspectives* (2004): Volume 18, Number 3, pp. 25-46.

Q. EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE CE METHOD IN YOUR ANALYSIS.

A. The CE method is excluded because the choice of which companies are comparable is highly subjective, and it is debatable whether historic accounting values are representative of the future. Moreover, its historical usage in this regulatory forum has been minimal.

<u>SUMMARY OF THE COMPANY'S RESULTS</u>

Q. WHAT ARE THE RESULTS OF THE COMPANY'S COST OF EQUITY ANALYSES?

A. Mr. Moul employed the DCF, CAPM, RP, and CE methods in analyzing the Company's cost of equity. He makes several adjustments to his results, which include consideration of risk, leverage, and size.[15] Ultimately, Mr. Moul opines that a cost of equity of 11.20% is warranted due to UGI Gas' risk characteristics, so it can compete in the capital markets, attain reasonable credit quality, and be recognized for the Company's strong management performance.[16]

<u>I&E RECOMMENDATION</u>

Q. WHAT IS YOUR RECOMMENDED COST OF COMMON EQUITY FOR UGI GAS?

A. Based upon my analysis, I recommend a cost of common equity of 9.92%.[17]

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the use of the DCF method. As explained below, I used

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15 UGI Gas Exhibit B, Schedule 1, p. 2.
16 UGI Gas Statement No. 6, p. 50, lines 2-16.
17 I&E Exhibit No. 2, Schedule 1.

my CAPM result only to present to the Commission a comparison to my DCF results. My DCF analysis uses a spot dividend yield, a 52-week dividend yield, and earnings growth forecasts.

<u>DISCOUNTED CASH FLOW</u>

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the constant growth DCF model as portrayed in the following formula:

$$K = D_1/P_0 + g$$

Where:

K	=	Cost of equity
D_1	=	Dividend expected during the year
P_0	=	Current price of the stock
g	=	Expected growth rate

When a forecast of D_1 is not available, D_0 (the current dividend) must be adjusted by one half of the expected growth rate to account for changes in the dividend paid in period one. As forecasts for each company in my proxy group were available from Value Line, no dividends were adjusted for the purpose of my analysis.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. A representative dividend yield must be calculated over a time frame that avoids the problems of both short-term anomalies and stale data series. For my DCF analysis, the dividend yield calculation places equal emphasis on the most recent spot and the 52-week average dividend yields. The following table summarizes my dividend yield computations for the proxy group:[18]

Proxy Group - Average Dividend Yields	
Spot	3.23%
52-week average	3.55%
Average	3.39%

Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. I have used five-year projected growth rate estimates from Value Line, Yahoo! Finance, Zacks, and Morningstar.

Q. WHAT WERE THE RESULTS OF YOUR FORECASTED EARNINGS GROWTH RATES?

A. The expected average growth rates for my gas proxy group ranged from 4.63% to 7.33% with an overall average of 6.53%.[19]

[18] I&E Exhibit No. 2, Schedule 4.
[19] I&E Exhibit No. 2, Schedule 5.

Q. WHAT IS THE RESULT OF YOUR DCF ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELD AND GROWTH RATE?

A. The results of my DCF analysis are calculated as follows:[20]

K	=	D_1/P_0	+	g
9.92%	=	3.39%	+	6.53%

<u>**CAPITAL ASSET PRICING MODEL**</u>

Q. PLEASE EXPLAIN YOUR CAPM ANALYSIS.

A. My analysis employs the traditional CAPM as portrayed in the following formula:

$K = R_f + \beta(R_m - R_f)$

Where:

K	=	Cost of equity
R_f	=	Risk-free rate of return
R_m	=	Expected rate of return on the overall stock market
β	=	Beta measures the systematic risk of an asset

Q. WHAT IS BETA AS EMPLOYED IN YOUR CAPM ANALYSIS?

A. Beta is a measure of the systematic risk of a stock in relation to the rest of the stock market. A stock's beta is estimated by calculating the linear regression of a stock's return against the return on the overall stock market. The beta of a stock with a price pattern identical to that of the overall stock market will equal one. A stock with a price

[20] I&E Exhibit No. 2, Schedule 6.

movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Conversely, a stock with a price movement that is less than the overall stock market will have a beta of less than one and would be described as having less investment risk than the overall stock market.

Q. HOW DID YOU DETERMINE YOUR BETA FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for my proxy group, I used the average of the betas for the companies as provided in the Value Line Investment Survey. The average beta for my proxy group is 0.84.[21]

Q. WHAT RISK-FREE RATE OF RETURN HAVE YOU USED FOR YOUR FORECASTED CAPM ANALYSIS?

A. I have chosen to use the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Notes. While the yield on the short-term T-Bill is a more theoretically correct parameter to represent a risk-free rate of return, it can be extremely volatile. The volatility of short-term T-Bills is directly influenced by Federal Reserve policy. At the other extreme, the 30-year Treasury Bond exhibits more stability but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation. Long-term treasuries normally offer higher yields to compensate investors for these risks. As a result, I chose to use the yield on the 10-year Treasury Note because it mitigates the shortcomings of the other two alternatives.

[21] I&E Exhibit No. 2, Schedule 7.

Additionally, the Commission has recently agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[22]

The forecasted yield on the 10-year Treasury Note, as seen in Blue Chip Financial Forecasts, is expected to range between 2.00% and 2.50% from the second quarter of 2022 through the second quarter of 2023, and it is forecasted to be 2.90% from 2023-2027. For my forecasted CAPM analysis, I used 2.35%, which is the average of all the yield forecasts I observed.[23]

Q. HOW DID YOU DETERMINE THE RETURN ON THE OVERALL STOCK MARKET EMPLOYED IN YOUR FORECASTED CAPM ANALYSIS?

A. To arrive at a representative expected return on the overall stock market, I observed Value Line's 1700 stocks and the S&P 500. Value Line expects its universe of 1700 stocks to have an average yearly return of 12.57% over the next three to five years based on a forecasted dividend yield of 1.90% and a yearly index appreciation of 50%. The S&P 500 index is expected to have an average yearly return of 15.41% over the next five years based upon Barron's forecasted dividend yield of 1.41% and Morningstar's average expected increase in the S&P 500 index of 13.90%.[24]

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22 *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99.

23 I&E Exhibit No. 2, Schedule 8.

24 I&E Exhibit No. 2, Schedule 9.

Q. WHAT IS THE EXPECTED RETURN ON THE OVERALL STOCK MARKET BASED ON YOUR FORECASTED ANALYSIS?

A. The expected return on the overall market is 13.99% for my forecasted analysis.[25]

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS?

A. The result of my analysis is as follows:[26]

K	=	R_f	+	$\beta(R_m - R_f)$
12.13%	=	2.35%	+	0.84 (13.99% - 2.35%)

<u>CRITIQUE OF MR. MOUL'S PROPOSED COST OF EQUITY</u>

Q. DO YOU AGREE WITH MR. MOUL'S PROPOSED COST OF EQUITY?

A. No. I disagree with Mr. Moul's proposed cost of equity analysis for several reasons. First, I disagree with the weights given to the results of Mr. Moul's CAPM, RP, and CE analyses in his recommendation. Second, I take issue with certain aspects of Mr. Moul's risk analysis of UGI Gas. Third, I disagree with his application of the DCF including the forecasted growth rate and leverage adjustment he uses. Fourth, I do not agree with his use of the 30-year Treasury Bond in place of the 10-year Treasury Note, his inclusion of a size adjustment, and use of an inflated beta in his CAPM analysis. Finally, I disagree with Mr. Moul's recommendation to include an adjustment to the cost of equity for recognition of management performance.

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[25] I&E Exhibit No. 2, Schedule 9.

[26] I&E Exhibit No. 2, Schedule 10.

<u>WEIGHTS GIVEN TO THE CAPM, RP, AND CE METHODS</u>

Q. DO YOU AGREE WITH MR. MOUL'S RELIANCE ON THE CAPM AND RP MODELS?

A. No. While I am not opposed to providing the Commission the results of the CAPM methodology for a point of comparison to the results of the DCF calculation, I am opposed to giving the CAPM and RP considerable weight. For the reasons previously discussed in this testimony, including my reference to recent Commission orders, it is inappropriate to give the CAPM and RP models similar weight to the DCF as Mr. Moul has done in creating his recommended cost of equity range.[27] As discussed above, the CAPM measures the cost of equity indirectly and can be manipulated by the time period chosen. Since the RP is a simplified version of the CAPM, it suffers these same flaws.

Q. DO YOU AGREE WITH MR. MOUL'S USE OF THE CE METHOD?

A. No. The companies in Mr. Moul's analysis are not utilities, and, therefore, they are too dissimilar to be used in a CE analysis. The companies in Mr. Moul's CE proxy group are simply not comparable to gas utilities in terms of business risk or financial risk profile. Natural gas distribution companies are monopolies, which are subject to very little competition, if any at all. Due to this minimal competition, utilities in general have very low business risk and can maintain higher financial risk profiles by employing more leverage. Conversely, since the companies in Mr. Moul's CE proxy group operate in an unregulated competitive environment with a higher level of business risk, they must maintain lower financial risk profiles by employing a smaller amount of leverage.

[27] UGI Gas Statement No. 6, p. 6, ln. 10 through p. 7, ln. 3.

Further, in his CE analysis, Mr. Moul states, “I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach.”[28] I do not believe this arbitrary use of 20% is justified, as I am unaware of any natural gas utility company that has been granted a Commission authorized or regularly earns a 20% or greater return on equity.

RISK ANALYSIS

Q. PLEASE SUMMARIZE MR. MOUL’S CLAIMS REGARDING THE RISK FACTORS THE COMPANY FACES.

A. Mr. Moul described the Company’s claimed risk factors in two different sub-sections. In the first section, labeled “Natural Gas Risk Factors,” he described the *qualitative* risk factors. In this section, Mr. Moul discussed the potential for bypass, the Company’s construction program, and the proposed weather normalization adjustment (WNA) mechanism.[29] In the second section of his risk analysis, labeled “Fundamental Risk Analysis,” he described the *quantitative* risk factors. In this section, Mr. Moul discusses the Company’s credit quality, as well as many different financial metrics including size, market ratios, common equity ratios, return on book equity, operating ratios, pre-tax interest coverage, quality of earnings, internally generated funds, and betas.[30]

Q. WHAT HAS MR. MOUL CLAIMED REGARDING THE POTENTIAL RISK OF BYPASS?

A. Mr. Moul opines that the Company’s close proximity to the Marcellus Shale production

[28] UGI Gas Statement No. 6, p. 49, lines 15-17.
[29] UGI Gas Statement No. 6, p. 7, ln. 12 through p. 14, ln. 2.
[30] UGI Gas Statement No. 6, p. 14, ln. 3 through p. 20, ln. 3.

area, and the competition gas utilities face from alternative energy sources such as electricity, fuel oil, and propane contribute to the Company's risk profile.[31]

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIMED RISK OF BYPASS FOR UGI GAS?

A. All natural gas distribution utilities face competition from the alternate sources of energy Mr. Moul mentions. Furthermore, all gas utilities face similar risk with competitive market customers. The overlapping territories in western Pennsylvania provide a good example. In my opinion, UGI Gas faces no more risk than any of the companies in my proxy group. The cost of equity measured by my proxy group adequately compensates investors for these risks common to all gas utilities.

Q. WHAT IS MR. MOUL'S CLAIM REGARDING ADDITIONAL RISK DUE TO THE COMPANY'S CONSTRUCTION PROGRAM AND AGING INFRASTRUCTURE?

A. Mr. Moul claims that the Company must invest in new facilities to meet growth demands and to maintain and upgrade existing facilities to maintain safe and reliable service to existing customers.[32] The Company anticipates that gross construction expenditures will represent a 59% increase in net utility plant, including construction work in progress during 2022-2025 period.[33]

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[31] UGI Gas Statement No. 6, p. 8, lines 6-18.
[32] UGI Gas Statement No. 6, p. 10, lines 5-9.
[33] UGI Gas Statement No. 6, p. 11, lines 1-4.

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIM REGARDING THE COMPANY'S CONSTRUCTION PROGRAM AND REPLACEMENT OF AGING INFRASTRUCTURE?

A. First, Mr. Moul states, "[w]ith customer demand for the Company's service at high levels, the Company is faced with the requirement to invest in new facilities…"[34] It is worth noting that this statement is contrary to Mr. Moul's concerns regarding loss of customers and risk of bypass as discussed above. Every gas utility faces the same issues of upgrading or replacing its infrastructure. As costs for replacing infrastructure increase, UGI Gas, like any other regulated gas utility, has the option to file a base rate case at any time to address revenue inadequacy due to increasing costs, infrastructure replacement, or any other associated issues. Base rate cases allow a utility to recover its costs and provide it with the *opportunity* to earn a reasonable return on capital investments. Additionally, the Commission offers risk reducing mechanisms such as the Distribution System Improvement Charge (DSIC) and the FPFTY to help reduce any regulatory lag in recovery of infrastructure investment or other unforeseen expenditures. It should be noted that these mechanisms were not designed to eliminate the need for periodic base rate case filings, but only to mitigate regulatory lag and support increasing infrastructure replacement needs.

Q. ACCORDING TO MR. MOUL, WHAT ADDITIONAL BUSINESS RISKS AFFECT THE COMPANY?

A. Mr. Moul suggests that regulatory risks such as the requirements to obtain the necessary

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[34] UGI Gas Statement No. 6, p. 10, lines 5-7.

permits and approvals to secure adequate and reliable gas supply have become time consuming and costly.[35] Further, he opines that the Company faces operational risks such as counterparty risk, cyber security, and attacks from foreign enemies and domestic terrorists.[36]

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIMS REGARDING THE VARIOUS BUSINESS (REGULATORY AND OPERATIONAL) RISKS HE MENTIONS?

A. The issues referenced by Mr. Moul affect the entire gas utility industry, therefore, UGI Gas faces the same exposure to these issues as do all the other companies in our respective proxy groups. Investors voluntarily buy and hold shares of stocks in natural gas utility companies, indicating they are aware of these risks and the returns. The cost of equity I present for UGI Gas in this proceeding is adequately measured by my proxy group and adequately compensates investors for these risks.

Q. PLEASE COMMENT ON THE COMPANY'S PROPOSAL REGARDING A WEATHER NORMALIZATION ADJUSTMENT (WNA) MECHANISM AND ITS CLAIM REGARDING THE POTENTIAL IMPACT ON THE COMPANY'S COST OF EQUITY.

A. Generally, the goal of a WNA is to stabilize revenues from volumetric charges as they are highly variable depending on weather conditions. Company witness John D. Taylor (UGI Gas Statement No. 11) discusses in detail the specifics of UGI Gas' WNA proposal.

[35] UGI Gas Statement No. 6, p. 9, lines 8-13.
[36] UGI Gas Statement No. 6, p. 9, lines 15-21.

Mr. Moul claims that all the companies in his Gas Group have similar WNA mechanisms to what UGI Gas is proposing in this proceeding, and that his market-determined return on equity analysis reflects the effects of decoupling on investor expectations.[37]

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIM REGARDING THE COMPANY'S PROPOSED WNA MECHANISM?

A. The Commission allows utilities the opportunity to propose alternative ratemaking mechanisms such as the WNA requested by the Company in this proceeding. If the Commission approves the Company's WNA proposal, the benefits of revenue decoupling would certainly reduce the Company's overall risk profile. However, I&E's position on UGI Gas' specific request regarding the WNA proposal are addressed in the testimony of I&E witness Cline (I&E Statement No. 4).

Q. PLEASE DISCUSS THE CLAIMS MR. MOUL MAKES REGARDING QUANTITATIVE RISK FACTORS IN THE SECTION HE LABELS "FUNDAMENTAL RISK ANALYSIS."

A. Mr. Moul states that it is necessary to establish a company's relative risk position within its industry through an analysis of quantitative and qualitative factors. In this section, Mr. Moul uses various financial metrics to compare UGI Gas to the S&P Public Utilities Index and his Gas Group.[38]

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[37] UGI Gas Statement No. 6, p. 12, lines 4-11.
[38] UGI Gas Statement No. 6, p. 14, lines 6-13.

Q. WHAT ARE YOUR COMMENTS REGARDING MR. MOUL'S "FUNDAMENTAL RISK ANALYSIS?"

A. Two of the points he examines, size risk and betas, are discussed and disputed elsewhere in my direct testimony. Throughout the remainder of his "fundamental risk analysis," Mr. Moul makes several statements to indicate that UGI Gas has no more of a risk than any other company in his Gas Group. First, Mr. Moul identifies the Company's long-term issuer credit quality rating from Moody's Investors Service (Moody's) to be A2, which is categorized as upper-medium investment grade with low credit risk. By comparison, the average Moody's ratings of Mr. Moul's Gas Group and the S&P Public Utilities Index both have a rating one step lower at A3.[39] These ratings indicate that UGI Gas has a lower credit risk than both Mr. Moul's Gas Group and the S&P Public Utilities Index.

Second, while discussing common equity ratios, Mr. Moul states, "The five-year average common equity ratios, based on permanent capital, were 56.6% for UGI Gas, 51.5% for the Gas Group, and 41.3% for the S&P Public Utilities." He concludes that UGI Gas' higher common equity ratio indicates lower financial risk than that of his Gas Group.[40]

Third, regarding operating ratios, Mr. Moul states, "The five-year average operating ratios were 76.7% for the Company, 83.6% for the Gas Group, and 78.8% for the S&P Public Utilities".[41] As Mr. Moul explains, the operating ratio illustrates the percentage of revenue required to cover operating expenses. The lower the operating

[39] UGI Gas Statement No. 6, p. 15, lines 11-19.
[40] UGI Gas Statement No. 6, p. 17, lines 3-7.
[41] UGI Gas Statement No. 6, p. 17, lines 20-21.

ratio is, the higher the operating margin becomes.[42] In this case, UGI Gas's lower operating ratio implies less risk than the Gas Group and the S&P Public Utilities Index.

Fourth, concerning coverage, he explains that excluding the Allowance for Funds Used During Construction, the five-year average pre-tax interest coverage was 5.07 times for the Company, 4.05 times for the Gas Group, and 3.02 times for the S&P Public Utilities. Mr. Moul acknowledges that "[t]he interest coverages were higher for the Company as compared to the Gas Group, thereby indicating lower credit risk."[43]

Fifth, regarding quality of earnings, Mr. Moul concludes, "[q]uality of earnings has not been a significant concern for the Company, the Gas Group, and the S&P Public Utilities."[44]

Finally, concerning internally generated funds (IGF), Mr. Moul shows the five-year average percentage of IGF to capital expenditures to be 72.4% for UGI Gas, 56.0% for his Gas Group, and 69.5% for the S&P Public Utilities.[45] Although the Company's IGF to capital expenditures dropped in 2019 and 2020, the higher five-year average percentage indicates lower financial risk as compared to the Gas Group and the S&P Public Utilities.

Q. PLEASE CONTINUE.

A. Mr. Moul summarizes his fundamental risk analysis by stating, "[o]n balance, the cost of equity measured with the Gas Group data will provide a reasonable, albeit conservative, representation of the Company's cost of equity."[46] While some measures he discusses

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42 UGI Gas Statement No. 6, p. 17, lines 18-20 and Footnote 3.
43 UGI Gas Statement No. 6. p. 18, lines 5-9.
44 UGI Gas Statement No. 6. p. 18, lines 21-22.
45 UGI Gas Statement No. 6. p. 18, ln. 23 through p. 19, ln. 4.
46 UGI Gas Statement No. 6, p. 20, lines 1-3.

may imply a higher risk profile for the Company, he provides a greater amount and more convincing measures that illustrate the Company has lower risk. Overall, through his own analysis and testimony, Mr. Moul substantiated that the Company has very similar risk as compared to that of his Gas Group, therefore, any additional consideration for the Company's risk profile is unnecessary.

COST OF EQUITY ADJUSTMENTS

INFLATED GROWTH RATES USED IN DCF ANALYSIS

Q. WHAT GROWTH RATE HAS MR. MOUL USED IN HIS DCF ANALYSIS?

A. Mr. Moul has chosen a growth rate of 6.75%.

Q. WHAT IS THE BASIS FOR MR. MOUL'S GROWTH RATE?

A. Mr. Moul indicates that Schedule 9 of his exhibit shows the prospective five-year earnings per share growth rates projected for the Gas Group to be 5.41% from IBES/First Call, 5.88% from Zacks, and 7.61% from Value Line.[47] Although the average of his sources for the growth rate is 6.30%,[48] Mr. Moul chooses to use 6.75% claiming that DCF growth rates should not be established by mathematical formulation and that the reasonableness of his chosen growth rate is justified by investor-expected growth for the Gas Group and continuation of gas utility infrastructure spending.[49]

Q. DO YOU AGREE WITH MR. MOUL'S GROWTH RATE ANALYSIS?

A. No. Contrary to Mr. Moul's belief that DCF growth rates *should not* be established by

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[47] UGI Gas Statement No. 6, p. 31, lines 12-13.
[48] (5.41% + 5.88% + 7.61%) ÷ 3 = 6.30%.
[49] UGI Gas Statement No. 6, p. 32, lines 8-15.

mathematical formulation, I feel that any alternative is subjective and introduces additional and unnecessary bias and should be avoided when possible. The use of a higher growth rate than the average of his proxy group ignores the fact that analysts making earnings per share growth forecasts are already aware of the economic conditions and the state of the gas utility industry. The reasons Mr. Moul has given for choosing a growth rate above his calculated average are factors that are already included in the earnings per share growth forecasts; thus, choosing a growth rate higher than the average of his proxy group would account for the same factors twice.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE RESULTS OF MR. MOUL'S PROJECTED GROWTH RATES?

A. Yes. While the five-year projected growth rates can be used in analyses, one must be aware that analysts' estimates may be biased. This bias has been observed in literature. An article authored by Professors Ciciretti, Dwyer, and Hasan in 2009 observed strong support of earnings forecasts being higher than actual earnings.[50] In spring of 2010, McKinsey on Finance presented an article reporting that after a decade of stricter regulation analysts' forecasts are still overly optimistic.[51]

Analysts' estimates are an attempt to forecast future cash flows and thus expected earnings growth. However, it should be kept in mind that prudent judgment must be exercised as to the sustainability of forecasted growth rates with respect to the base earnings. If the base year earnings are abnormally high, the growth rates from which

[50] Ciciretti, Rocco; Dwyer, Gerald R; and Iftekhan Hasan. "Investment Analysts' Forecasts of Earnings" Federal Reserve Bank of St. Louis *Review*, September/October 2009, 91 (5, part 2) pp. 545-67.

[51] Goedhart, Marc J; Raj, Rishi; and Abhishek Saxena. "Equity analyst: Still too bullish" McKinsey on Finance Number 35 Spring 2010, pp. 14-17.

they are calculated will be biased downward. Similarly, if the base year earnings are abnormally low, the growth rates from which they are calculated will be biased upward. As a result, it is typically necessary to employ a methodology to smooth out the abnormally high or low base year earnings.

In summary, since analysts' projected growth forecasts are most often overly optimistic, there is no need to arbitrarily and non-formulaically increase the estimates used in a DCF analysis.

LEVERAGE ADJUSTMENT APPLIED TO DCF ANALYSIS

Q. HAS MR. MOUL MADE ANY ADDITIONAL ADJUSTMENTS TO THE RESULT OF HIS DCF ANALYSIS?

A. Yes. Mr. Moul proposes to make a 95-basis point "leverage" adjustment[52] to the results of his DCF analysis to account for applying a market-determined cost of equity to a book value capital structure.[53]

Q. WHAT IS FINANCIAL LEVERAGE?

A. Financial leverage is the use of debt capital to supplement equity capital. A firm with significantly more debt than equity is considered highly leveraged.

Q. WHAT IS A MARKET-TO-BOOK (M/B) RATIO?

A. A market-to-book ratio is used to evaluate a public firm's equity value by comparing the market value and book value of a company's equity. One way of doing this is to divide

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[52] UGI Gas Exhibit B, Schedule 1, p. 2.
[53] UGI Gas Statement No. 6, p. 33, lines 12-14.

the current price per share of stock by the book value per share. A M/B result of above one (1) is desired.

Q. HAS MR. MOUL PROPOSED TO ADJUST THE RESULT OF HIS DCF ANALYSIS TO RECOGNIZE HOW THE COMPANY IS LEVERAGED?

A. No. Mr. Moul does not propose to change the capital structure of the utility (a leverage adjustment), nor does he proposed to apply the market-to-book ratio to the DCF model (a market-to-book adjustment). Instead, Mr. Moul proposes to make an adjustment to account for applying the market value cost rate of equity to the book value of the utility's capital structure. I am not aware of any term in academic journals, textbooks, or other literature that describes this type of adjustment.

Q. WHAT IS THE BASIS FOR MR. MOUL'S PROPOSED LEVERAGE ADJUSTMENT?

A. As stated above, Mr. Moul theorizes that to make the DCF results relevant to a book value capital structure, the market-derived cost of equity needs to be adjusted to take into consideration the difference in financial risk.[54] Mr. Moul opines this is because market valuations of equity are based on market value capital structures, which in general have more equity, less debt, and therefore, less risk than book value capital structures.[55]

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[54] UGI Gas Statement No. 6, p. 33, lines 12-14.
[55] UGI Gas Statement No. 6, p. 33, lines 4-10.

Q. HOW DOES MR. MOUL CALCULATE THE LEVERAGE ADJUSTMENT USED IN HIS ANAYSIS?

A. Mr. Moul simply states:

> I know of no means to mathematically solve for the 0.95% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.95% adjustment is merely a convenient way to compare the 11.21% return computed using the Modigliani & Miller formulas to the 10.26% return generated by the DCF model based on a market-value capital structure.[56]

Q. DO YOU AGREE WITH MR. MOUL'S "LEVERAGE ADJUSTMENT"?

A. No. Mr. Moul's adjustment is inappropriate for a couple of reasons, including the characterization of financial risk and its inconsistency with Commission precedent.

Q. EXPLAIN HOW RATING AGENCIES ASSESS FINANCIAL RISK.

A. Rating agencies assess financial risk based upon a company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations. The agencies use a company's financial statements for their analysis, not market capital structure. The income statement reflects the financial risk of a company because it represents the performance of the company over a certain period. A change in the market value of the stock is not reflected in the income statement nor is a change in market value capital structure reflected in the book value capital structure unless treasury stock is purchased. It is a company's financial statements that affect the market value of the stock, and, therefore, the financial statements and the book value capital structure are relied upon in an analysis such as that done by rating agencies.

[56] UGI Gas Statement No. 6, p. 36, lines 17-23.

Q. WHAT ARE THE MOST RECENT COMMISSION DECISIONS REGARDING A LEVERAGE ADJUSTMENT?

A. The following cases are the most recent instances where the Commission has addressed the use of a "leverage adjustment." In these cases, this adjustment has been rejected.

First, in *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, at Docket No. R-00072711 (Order Entered July 31, 2008), pp. 38-39, the Commission rejected the ALJ's recommendation for a leverage adjustment stating, "[t]he fact that we have granted leverage adjustments in the past does not mean that such adjustments are indicated in all cases." In this proceeding, the Commission determined that there was no viable support for an upwards adjustment to compensate for any perceived risk.

Second, in *Pennsylvania Public Utility Commission, et al v. City of Lancaster – Bureau of Water*, at Docket No. R-2010-2179103 (Order Entered July 14, 2011), p. 101, the Commission agreed with the I&E position and stated, "any adjustment to the results of the market based DCF are unnecessary and will harm ratepayers. Consistent with our determination in *Aqua 2008* there is no need to add a leverage adjustment. . ."

Third, in *Pennsylvania Public Utility Commission, et al v. UGI Utilities, Inc. – Electric Division*, at Docket No. R-2017-2640058 (Order Entered October 25, 2018), pp. 93-94, the Commission agreed with the I&E position and stated, "we conclude that an artificial adjustment in this proceeding is unnecessary and contrary to the public interest. Accordingly, we decline to include a leverage adjustment in our calculation of the DCF cost of equity."

Fourth, in *Pennsylvania Public Utility Commission, et. al v. Columbia Gas of Pennsylvania, Inc.*, at Docket R-2020-3018835 (Order Entered February 19, 2021), pp.

137-141, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded Columbia's application of a leverage adjustment.

Finally, in the most recent case of *Pennsylvania Public Utility Commission, et. al v. PECO Energy Company – Gas Division*, at Docket R-2020-3018929 (Order Entered June 22, 2021, Public Version), pp. 172-173, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded PECO's application of a leverage adjustment.

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 95 BASIS POINTS FOR MR. MOUL'S LEVERAGE ADJUSTMENT TO THE COST OF EQUITY?

A. The example below illustrates the impact of 95 additional basis points for the leverage adjustment to the Company's cost of equity:

UGI Utilities, Inc. - Gas Division	
Claimed Equity Percentage of Capital Structure	55.12%
Additional Basis Points to Calculated Cost of Equity	95
Claimed Rate Base*	$3,169,023,000
Impact Prior to Gross Up (0.5512 x 0.0095 x $3,169,023,000)	$16,594,272
Gross Revenue Conversion Factor**	1.429864
Total Impact ($16,594,272 x 1.429864)	**$23,727,552**
*UGI Gas Exhibit A, Schedule A-1, ln. 9. **UGI Gas Exhibit A, Schedule A-1, ln. 24.	

In this example, an addition of 95 basis points for the leverage adjustment to the cost of equity would force ratepayers to fund an unwarranted additional amount of $23,727,552 annually to cover the increase of the inflated rate of return along with the associated impact resulting from increases to income taxes, gross receipts tax, uncollectibles, and assessments.

Q. SUMMARIZE YOUR RECOMMENDATION REGARDING THE PROPOSED LEVERAGE ADJUSTMENT.

A. I recommend that Mr. Moul's proposed 95-basis point leverage adjustment be rejected because true financial risk is a function of the amount of interest expense, and capital structure information provided to investors through Value Line is that of book values, not market values. This demonstrates that investors base their decisions on book value debt and equity ratios for the regulated utilities; therefore, no adjustment is needed. Mr. Moul's proposed adjustment serves only to manipulate the DCF's market-based methodology and causes undue harm to ratepayers as illustrated above.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING MR. MOUL'S DCF CALCULATION?

A. Yes. While I am not directly disputing Mr. Moul's adjusted dividend yields, it is important to recognize that, as cited above, the Commission has recently agreed with I&E's DCF methodology which includes the appropriate calculation of dividend yields. Although it is acceptable to adjust historical dividend yields as Mr. Moul has done, it is preferable to use forecasted dividends to calculate the dividend yields when available, such as the ones offered by Value Line that I have employed.

Q. WHAT WOULD MR. MOUL'S DCF BE WITHOUT ANY ADJUSTMENTS?

A. Without Mr. Moul's use of inflated growth rates and a leverage adjustment, his DCF would consist of a dividend yield of 3.51% and an average growth rate of 6.30%, which results in an 9.81% cost of equity. This result is slightly lower, yet comparable to my DCF result of 9.92% and is much more reasonable than his originally calculated and inappropriately inflated result of 11.21%.

<u>RISK-FREE RATE OF RETURN</u>

Q. HOW HAS MR. MOUL CALCULATED HIS RISK-FREE RATE FOR USE IN HIS CAPM MODEL?

A. Mr. Moul's calculation of his risk-free rate is similar to mine. He considered Treasury yield estimates published by Blue Chip Financial Forecasts over the next six quarters, from the time of his analysis, as well as long-range, five-year averages. However, he used the 30-year Treasury Bond while I employed the 10-year Treasury Note. Also, where I used a long-range, five-year average, future data point accounting for years 2023-2027 predictions, Mr. Moul used two future data points accounting for not only years 2023-2027, but also included an estimate for years 2028-2032. His calculation resulted in a 2.75% risk-free rate as opposed to the 2.35% I used.[57]

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S CALCULATION OF THE RISK-FREE RATE?

A. First, I must reiterate my earlier statements that long-term Treasury Bonds have

[57] UGI Gas Statement No. 6, p. 43, ln. 14 through p. 45, ln. 5 and UGI Gas Exhibit B, Schedule 13, p. 2.

substantial maturity risk associated with the market risk and the risk of unexpected inflation and normally offer higher yields to compensate investors for these risks. Using the 10-year Treasury Note is more appropriate to balance the short-term volatility risk and the long-term inflation risk.

The Commission has recently recognized the 10-year Treasury Note as the superior measure for the risk-free rate by stating the following: [58]

> We agree with I&E and the ALJs that using the yield on the 10-year Treasury Note provides a better measure of the risk-free rate of return than using the yield on the 30-year Treasury Bond, as recommended by UGI. In our view, using the 10-year Treasury Note balances the shortcomings of the short-term T-Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with the market risk. In addition, long-term Treasury Bonds bear the risk of unexpected inflation.

Additionally, the further out into the future one projects, the less reliable the information becomes. Using the projection for 2028-2032 is an unreliable measure and this should not be included in the risk-free rate. The Company's FPFTY ends September 30, 2023, and in my opinion using an estimated risk-free rate that is up to nine years beyond the FPFTY is unreasonable and unnecessary.

<u>INFLATED BETAS USED IN CAPM ANALYSIS</u>

Q. HOW HAS MR. MOUL INFLATED THE BETAS EMPLOYED IN HIS CAPM ANALYSIS?

A. Mr. Moul has used the same logic for inflating his CAPM betas from 0.88 to 1.00 that he

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[58] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order entered October 25, 2018), p. 99. (Disposition of Capital Asset Pricing Model (CAPM)).

used to enhance his DCF returns, through a financial risk or "leverage" adjustment.[59]

Q. DO YOU AGREE WITH MR. MOUL'S USE OF ADJUSTED BETAS?

A. No. Such enhancements are unwarranted for beta in a CAPM analysis for the same reasons that the "leverage" adjustment is unwarranted for DCF results.

Additionally, if the unadjusted *Value Line* betas do not reflect an accurate investment risk as Mr. Moul contends, the question naturally arises as to why *Value Line* does not publish betas that are adjusted for leverage. Until this type of adjustment is demonstrated in the academic literature to be valid, such leverage adjusted betas in a CAPM model should be rejected.

Finally, as described in my CAPM analysis above, a stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Due to being regulated and the monopolistic nature of utilities, very rarely do they have a beta equal to or greater than one. Therefore, in this case, to apply an adjusted beta of 1.00 to the entire industry or gas proxy group is irrational.

<u>SIZE ADJUSTMENT APPLIED TO CAPM ANALYSIS</u>

Q. PLEASE EXPLAIN MR. MOUL'S PROPOSED SIZE ADJUSTMENT.

A. Mr. Moul adds 102 basis points to his CAPM indicated cost of common equity because he believes that as the size of a firm decreases, its risk and required return increases. Mr. Moul relies upon technical literature including the Stocks, Bonds, Bills, and Inflation

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[59] UGI Gas Statement No. 6, p. 42, ln. 14 through p. 43, ln. 13.

Yearbook, a Fama and French study entitled "The Cross-Section of Expected Stock Returns," and an article published in Public Utilities Fortnightly entitled "Equity and the Small-Stock Effect."[60]

Q. DO YOU AGREE WITH MR. MOUL'S SIZE ADJUSTMENT?

A. No. Mr. Moul's proposed size adjustment is unnecessary because the technical literature he cites supporting investment adjustments relating to the size of a company is not specific to the utility industry, and therefore, has no relevance in this proceeding.

Q. IS THERE ACADEMIC EVIDENCE THAT SUPPORTS YOUR CONCLUSION THAT THE SIZE ADJUSTMENT FOR RISK IS NOT APPLICABLE TO UTILITY COMPANIES?

A. Yes. In the article "Utility Stocks and the Size Effect: An Empirical Analysis," Dr. Annie Wong concludes:

> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industriales, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.[61]

UGI Gas presents no evidence to support application of a non-utility study regarding a size adjustment for risk to a utility setting. Absent any credible article to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected.

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[60] UGI Gas Statement No. 6, p. 45, ln. 21 through p. 46 ln. 16.

[61] Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association* 1993, pp. 95-101.

Further, the Commission has recently rejected the application of a size adjustment to the CAPM cost of equity calculation where it agreed that the same literature the Company cites is not specific to the utility industry.[62]

Q. BASED ON THE COMPANY'S CLAIMED RATE BASE AND CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 102 BASIS POINTS FOR MR. MOUL'S SIZE ADJUSTMENT TO THE COST OF EQUITY?

A. The example below illustrates the impact of 102 additional basis points for the size adjustment to the Company's cost of equity:

UGI Utilities, Inc. - Gas Division	
Claimed Equity Percentage of Capital Structure	55.12%
Additional Basis Points to Calculated Cost of Equity	102
Claimed Rate Base*	$3,169,023,000
Impact Prior to Gross Up (0.5512 x 0.0102 x $3,169,023,000)	$17,817,008
Gross Revenue Conversion Factor**	1.429864
Total Impact ($17,817,008 x 1.429864)	**$25,475,898**
*UGI Gas Exhibit A, Schedule A-1, ln. 9. **UGI Gas Exhibit A, Schedule A-1, ln. 24.	

62 *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018), p. 100 (Disposition of Cost of Common Equity).

Q. WHAT WOULD MR. MOUL'S CAPM RESULT BE USING YOUR CALCULATED 10-YEAR TREASURY NOTE FOR HIS RISK-FREE RATE AND WITHOUT HIS SIZE ADJUSTMENT AND INFLATED BETAS?

A. Mr. Moul's CAPM result would be 11.13%. This is 242 basis points lower than his originally calculated 13.55% result. The calculation is repeated below without Mr. Moul's unnecessary adjustments:

Rf	+	*β*	x	*(Rm-Rf)*	+	*size*	=	*k*
2.35%	+	0.88	x	9.98%	+	0%	=	**11.13%**

MANAGEMENT PERFORMANCE

Q. DISCUSS THE COMPANY'S CLAIMS SPECIFIC TO MANAGEMENT PERFORMANCE.

A. Mr. Moul proposes that 20 basis points be added to the calculated cost of equity in recognition of the Company's exemplary management performance. He refers to the direct testimony of Company witness Christopher R. Brown (UGI Gas Statement No. 1) to support the consideration of additional basis points for UGI Gas' management performance.[63]

Q. WHAT INFORMATION DOES MR. BROWN PROVIDE TO SUPPORT THE COMPANY'S CLAIM OF EXEMPLARY MANAGEMENT PERFORMANCE?

A. Mr. Brown claims that UGI Gas' superior management performance has been

[63] UGI Gas Statement No. 6, p. 6, ln. 20 through p. 7, ln. 11.

demonstrated in recent years through management efforts that include excellent customer service, infrastructure improvements made in line with the Company's Long-Term Infrastructure Improvement Plan, investments in safety and training, modernization of information technology, environmental and social governance initiatives, community engagement, and diversity and inclusion.[64]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIMS REGARDING MANAGEMENT PERFORMANCE?

A. No. First, many of the topics presented by Mr. Brown fall within the categories of reliability, customer satisfaction, and safety which are required of every public utility company under 66 Pa C.S.A. §1501. Additionally, the Company passes capital expenditures to its ratepayers via base rates, or it can utilize a DSIC for capital expenditure recovery. Further, if the Company is effective at controlling operating and maintenance costs, those savings should flow through to ratepayers and/or investors. These savings would likely be offset by the addition of basis points for management performance as ratepayers would have to fund the additional costs. This defeats the purpose of any cost cutting measures to benefit ratepayers.

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 20 BASIS POINTS FOR THE CONSIDERATION OF MANAGEMENT PERFORMANCE TO THE COST OF EQUITY?

A. The example below illustrates the impact of 20 additional basis points for the

[64] UGI Gas Statement No. 1, p. 30, ln. 12 through p. 39, ln. 2.

consideration of management performance to the Company's cost of equity:

UGI Utilities, Inc. - Gas Division	
Claimed Equity Percentage of Capital Structure	55.12%
Additional Basis Points to Calculated Cost of Equity	20
Claimed Rate Base*	$3,169,023,000
Impact Prior to Gross Up (0.5512 x 0.0020 x $3,169,023,000)	$3,493,531
Gross Revenue Conversion Factor**	1.429864
Total Impact ($3,493,531 x 1.429864)	**$4,995,274**
*UGI Gas Exhibit A, Schedule A-1, ln. 9. **UGI Gas Exhibit A, Schedule A-1, ln. 24.	

In this example, an addition of 20 basis points to the cost of equity in consideration of management performance would force ratepayers to fund an unwarranted additional amount of $4,995,274 annually to cover the increase of the inflated rate of return along with the associated impact resulting from increases to income taxes, gross receipts tax, uncollectibles, and assessments.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CONSIDERATION OF ADDITIONAL BASIS POINTS FOR THE COMPANY'S MANAGEMENT PERFORMANCE?

A. Ultimately, as alluded to above, true strong management performance is earning a higher return through efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to both ratepayers and shareholders. I do not believe that UGI Gas, or any utility should be gifted additional basis points for doing what they are required to do to provide adequate, efficient, safe, and reasonable service under 66 Pa C.S.A. §1501.

For these reasons, I recommend that any addition of basis points to the cost of equity for management performance be disallowed.

<u>OVERALL RATE OF RETURN RECOMMENDATION</u>

Q. WHAT IS THE COMPANY'S PROPOSED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. The Company recommends a cost of equity of 11.20% and an overall rate of return of 7.96%.

Q. WHAT IS I&E'S RECOMMENDED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. I&E Exhibit No. 2, Schedule 1, shows the calculation of an appropriate cost of equity to be 9.92% with an overall rate of return for UGI Gas to be 7.26%.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE COMPANY'S PROPOSED RETURN ON EQUITY?

A. Yes. First, a report issued by <u>Regulatory Research Associates, a group within S&P</u>

Global Market Intelligence,[65] illustrates that UGI Utilities Inc. - Gas Division's 11.20% requested return on equity is a significant 99 basis points higher than the average return on equity request of 10.21% of all pending gas utility rate cases as of March 10, 2022.

Second, when asked, Mr. Moul indicated he was unaware if any natural gas distribution utilities throughout the United States were granted a Commission authorized return of 11.20% or higher cost of common equity in the past two years.[66]

Third, the Company's requested return on common equity is 100 basis points higher than the Commission's approved DSIC rate of 10.20% (Q3 2021 Quarterly Earnings Summary Report) for gas distribution companies. The DSIC rate is designed to encourage its use and to incentivize accelerated pipeline replacement and infrastructure upgrades to bring the existing aging infrastructure closer to meeting safety and reliability requirements in between base rate filings. Additionally, the DSIC rate establishes a benchmark above which a utility company is considered "overearning." As such, the DSIC rate does not serve as a proper measurement of a subject utility's cost of equity in a rate case proceeding. To suggest the cost of equity must be at or above the DSIC rate in this base rate proceeding is inappropriate and not in the public interest.

Finally, as detailed in the various charts above, the effect of Mr. Moul's adjustments to the market-determined cost of common equity are an enormous burden to ratepayers and are completely unwarranted and unnecessary. Although they are not cumulative, the impact to ratepayers of each of the disputed adjustments is summarized

[65] Regulatory Research Associates, "Major energy utility cases in progress in the US, Quarterly update on pending rate cases," *S&P Global Market Intelligence*, March 16, 2022.
[66] I&E Exhibit No. 2, Schedule 11.

as follows:

Leverage Adjustment	$23,727,552
Size Adjustment	$25,475,898
Management Performance	$4,995,274

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ANTHONY D. SPADACCIO, CRRA

PROFESSIONAL EXPERIENCE AND EDUCATION

EMPLOYMENT

Fixed Utility Financial Analyst 2014 – Present	PA Public Utility Commission Bureau of Investigation & Enforcement
Auditor 2012 – 2014	Public School Employee's Retirement System Bureau of Benefits Administration
Tax Technician 2010 – 2012	PA Department of Labor and Industry Unemployment Compensation Tax Services
Staff Accountant 2006 – 2009	Boyer & Ritter Certified Public Accountants

EDUCATION & TRAINING

EDUCATION/CERTIFICATIONS:

Society of Utility and Regulatory Financial Analysts (SURFA) – 2018
Certified Rate of Return Analyst (CRRA)

Indiana University of Pennsylvania, A.A. Accounting - 2006

The Pennsylvania State University, B.S. Labor and Industrial Relations – 2003

The Pennsylvania State University - The Smeal College of Business - 2003
Certificates of Completion:
Business Management - 20 credits of instruction
General Business - 20 credits of instruction

UTILITY SPECIFIC TRAINING/CONFERENCES:

NARUC Staff Subcommittee on Accounting & Finance, Fall 2021 webinar, October 5-7, 2021

NARUC Staff Subcommittee on Accounting & Finance, Spring 2021 webinar, April 6-8, 2021

SURFA Annual Financial Forum – New Orleans, LA – 2018

SURFA Annual Financial Forum – Indianapolis, IN - 2016

Western NARUC Utility Rate School – San Diego, CA - 2015

Pennsylvania Public Utility Commission Rate School – Harrisburg, PA – 2014

EXPERIENCE

I have submitted testimony or assisted in the following proceedings:

- Docket No. A-2021-3027268 - Aqua PA Wastewater, Inc. – Acquisition of the Wastewater System Assets of Willistown Township (§1329)*
- Docket No. R-2021-3026682 – City of Lancaster – Water Fund*
- Docket Nos. R-2021-3027385 & R-2021-3027386 – Aqua Pennsylvania, Inc. & Aqua Pennsylvania Wastewater, Inc.*
- Docket Nos. R-2021-3024773, R-2021-3024774 & R-2021-3024779 – Pittsburgh Water & Sewer Authority*
- Docket No. R-2021-3024601 - PECO Energy Company – Electric Division*
- Docket No. R-2021-3023618 – UGI Utilities, Inc. – Electric Division*
- Docket No. R-2020-3022135 – Pike County Light & Power Company (Electric)*
- Docket No. R-2020-3022135 – Pike County Light & Power Company (Gas)*
- Docket No. R-2020-3020919 – Audubon Water Company*
- Docket No. R-2020-3020256 – City of Bethlehem – Bureau of Water*
- Docket Nos. R-2020-3019369 & R-2020-3019371 - Pennsylvania-American Water Company*
- Docket Nos. R-2020-3017951, R-2020-3017970 & P-2020-3019019 – Pittsburgh Water & Sewer Authority*
- Docket No. R-2020-3017206 – Philadelphia Gas Works*
- Docket No. R-2020-3017850 - Peoples Natural Gas Company, LLC 1307(f)*
- Docket No. R-2020-3017846 - Peoples Gas Company, LLC 1307(f)*
- Docket No. R-2019-3010955 – City of Lancaster – Sewer Fund*
- Docket No. R-2019-3008208 - Wellsboro Electric Company*
- Docket No. R-2019-3008212 - Citizens’ Electric Company of Lewisburg, PA*
- Docket No. R-2019-3008948 – Community Utilities of PA, Inc. – Wastewater Division*
- Docket No. R-2019-3008947 – Community Utilities of PA, Inc. – Water Division*
- Docket No. A-2019-3006880 – Pennsylvania-American Water Company – Acquisition of the Water Treatment and Distribution System Assets of Steelton Borough Authority (§1329)*
- Docket No. R-2018-3006814 – UGI Utilities, Inc. – Gas Division*
- Docket Nos. M-2018-2640802 & 2640803 – Pittsburgh Water & Sewer Authority (Compliance Plan)*
- Docket Nos. R-2018-3002645 & 3002647 - Pittsburgh Water & Sewer Authority*
- Docket Nos. A-2018-3003517 & 3003519 - SUEZ Water Pennsylvania, Inc. – Acquisition of the Water and Wastewater Assets of Mahoning Township (§1329)*
- Docket No. R-2018-3000124 - Duquesne Light Company*
- Docket No. R-2018-3000164 - PECO Energy Company – Electric Division*
- Docket No. R-2018-2645296 - Peoples Gas Company LLC 1307(f)*

- Docket No. R-2018-3000236 - Peoples Natural Gas – Equitable Division 1307(f)*
- Docket No. R-2018-2645278 - Peoples Natural Gas Company, LLC 1307(f)*
- Docket No. R-2017-2640058 - UGI Utilities, Inc. – Electric Division*
- Docket No. R-2017-2595853 - Pennsylvania-American Water Company*
- Docket No. A-2017-2606103 - Pennsylvania-American Water Company – Acquisition of Assets of the Municipal Authority of the City of McKeesport (§1329)*
- Docket No. A-2016-2580061 - Aqua PA Wastewater, Inc. – Acquisition of the Wastewater System Assets of New Garden Township and the New Garden Township Sewer Authority (§1329)
- Docket No. R-2016-2531551 - Wellsboro Electric Company*
- Docket No. R-2016-2531550 - Citizens' Electric Company of Lewisburg, PA*
- Docket No. R-2016-2542923 - PNG, LLC – Equitable Division (Rate MLX)*
- Docket No. R-2016-2542918 - Peoples Natural Gas Company, LLC (Rate MLX)*
- Docket No. P-2016-2543140 - Duquesne Light Company (DSP VIII)*
- Docket No. R-2016-2529660 - Columbia Gas of PA, Inc.*
- Docket No. R-2016-2538660 - Community Utilities of PA, Inc.
- Docket No. P-2016-2521993 - Columbia Gas of PA, Inc. (DSIC)*
- Docket No. R-2015-2506337 - Twin Lakes Utilities, Inc.
- Docket No. R-2015-2479955 - Allied Utility Services, Inc.
- Docket No. R-2015-2479962 - Corner Water Supply & Service Corp.
- Docket No. R-2015-2470184 - Borough of Schuylkill Haven – Water Dept.
- Docket No. R-2014-2452705 - Delaware Sewer Company*
- Docket No. R-2014-2430945 - Plumer Water Company
- Docket No. R-2014-2427189 - B.E. Rhodes Sewer Company
- Docket No. R-2014-2427035 - Venango Water Company
- Docket No. R-2014-2428745 - Metropolitan Edison Company
- Docket No. R-2014-2428744 - Pennsylvania Power Company
- Docket No. R-2014-2428743 - Pennsylvania Electric Company
- Docket No. R-2014-2428742 - West Penn Power Company

*Testimony Submitted

I&E Statement No. 2-SR
Witness: Anthony Spadaccio

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Surrebuttal Testimony

of

Anthony Spadaccio, CRRA

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

TABLE OF CONTENTS

<u>INTRODUCTION OF WITNESS</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Anthony Spadaccio. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME ANTHONY SPADACCIO WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND THE SCHEDULES IN I&E EXHIBIT NO. 2?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address statements made in the rebuttal testimonies of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) witnesses Christopher R. Brown (UGI Gas Statement No. 1) and Paul R. Moul (UGI Gas Statement No. 6-R) and the Pennsylvania Office of Consumer Advocate (OCA) witness David J. Garrett (OCA Statement 2R) regarding rate of return topics including the cost of common equity and the overall fair rate of return, which will be applied to the Company's rate base.

Q. DID THE COMPANY PROVIDE AN UPDATE TO ITS RATE OF RETURN?

A. Yes. The Company provided an update to its cost of long-term debt. The Company is now requesting a cost of long-term debt of 4.30% to reflect the cost of new issues of senior notes in May, July, and October 2022. The Company's update to its cost of long-term debt is an increase of 0.32% (4.30% - 3.98%) to its initial claim of 3.98%.[1] This results in an increase to the Company's overall requested rate of return from 7.96% to 8.10%. Below is the Company's updated rate of return claim:

UGI UTILITIES, INC. - GAS DIVISION
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
	UGI Utilities, Inc. - Gas Division		
Long-Term Debt	44.88%	4.30%	1.93%
Common Equity	55.12%	11.20%	6.17%
Total	100.00%		8.10%

[1] UGI Gas Statement No. 6-R, p. 13, lines 1-10.

<u>SUMMARY OF MR. GARRETT'S REBUTTAL TESTIMONY</u>

Q. SUMMARIZE MR. GARRETT'S RESPONSE IN REBUTTAL TESTIMONY TO YOUR RECOMMENDATIONS MADE IN DIRECT TESTIMONY.

A. Mr. Garrett takes issue with the growth rates I employ in my Discounted Cash Flow (DCF) analysis as well as the Equity Risk Premium (ERP) used in my Capital Asset Pricing Model (CAPM) analysis.[2]

Q. WHAT IS MR. GARRETT'S SPECIFIC CRITICISM REGARDING YOUR DCF ANALYSIS?

A. Mr. Garrett opines that the results of my DCF analysis are unreasonably high caused by the growth rate inputs I use. He claims that I rely on short-term growth rates as opposed to long-term growth rates resulting in unsustainable growth rate estimates. Mr. Garrett further reasons that it is near impossible to increase earnings by 10% year after year for decades. Finally, he argues that U.S. GDP growth should be viewed as a limiting factor on long-term growth for individual companies as it avoids the circular reference problem of short-term analysts' growth rates.[3]

[2] OCA Statement 2R, p. 1, lines 17-19.
[3] OCA Statement 2R, p. 2, ln. 8 through p. 3, ln. 21.

Q. HOW DO YOU RESPOND TO MR. GARRETT'S CRITICISMS OF YOUR DCF ANALYSIS?

A. First, it should be noted, in the context of recommending an appropriate return on equity and overall rate of return, I&E's role is to perform an unbiased analysis using current and reputable sources. In determining an appropriate growth rate for my DCF analysis, I relied upon the forecasted earnings estimates from Value Line, Yahoo! Finance, Zacks, and Morningstar.[4] These resources are trusted and used industry wide, including by most Company, advocate, and Commission witnesses who submit rate of return testimony. Other than Mr. Garrett, I do not recall another witness that does not give at least some consideration or weighting to these forecasted growth estimates.

Next, the estimates I use from the sources listed above are five-year growth forecasts which are not short-term, nor are they intended to be viewed as sustainable for decades. This time period is reasonable as it covers the Fully Projected Future Test Year (FPFTY) and rate case filing frequency of many utilities.

Additionally, using U.S. GDP growth as Mr. Garrett suggests ignores the strength of the DCF, which is its company and/or industry specific inputs. Also, it does not combat the circularity issue he mentions. With regulation in general, and specifically the use of proxy groups of similarly situated companies, and use of

[4] I&E Exhibit No. 2, Schedule 5.

generally accepted cost of equity models, there will always be some degree of circularity.

Finally, the Commission has repeatedly confirmed I&E's DCF methodology for determining a fair return on common equity. Specifically, in the 2020 Columbia Gas rate case, the Commission agreed with the ALJ's recommendation to use I&E's cost of equity methodology, which included using five-year growth estimates in the DCF analysis.[5]

Q. WHAT IS MR. GARRETT'S SPECIFIC CRITICISM REGARDING YOUR CAPM ANALYSIS?

A. Mr. Garrett notes that the result of my CAPM analysis is considerably higher than his own. He opines that the reason my CAPM result is overestimated is due to the ERP, which he argues is the single most important metric used to assess market risk and the cost of equity.[6]

Q. HOW DO YOU RESPOND TO MR. GARRETT'S CRITICISMS OF YOUR CAPM ANALYSIS?

A. To an extent, I agree with Mr. Garrett. I believe the differences in our applications of the CAPM illustrate just how subjective the inputs of this cost of equity model can be. For example, I agree with Mr. Moul that Mr. Garrett's implied total

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[5] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.;* Docket No. R-2020-3018835 (Order Entered February 19, 2021). *See generally* Disposition of Cost of Common Equity.

[6] OCA Statement No. 6R, p. 4, ln. 1through p. 6, ln. 2.

market return of 7.90% is nowhere near actual market returns of the past few years.[7] Additionally, like Mr. Moul, I question the sources he uses to determine the ERP, which include "expert surveys" from IESE Business School. When determining the overall market return and ERP, I am hesitant to set aside analysis from well-known and reputable financial institutions such as Morningstar, Barron's, and Value Line in favor of more obscure sources, for instance, school surveys.

In direct testimony, I thoroughly discuss the disadvantages of the CAPM and explain why the DCF is the superior model.[8] In the end, as I explain below, I do not base my recommendation on the CAPM, I simply provide the results as a comparison.

SUMMARY OF MR. MOUL'S REBUTTAL TESTIMONY

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY TO YOUR RECOMMENDATIONS MADE IN DIRECT TESTIMONY.

A. Mr. Moul disputes my recommendations regarding an appropriate proxy group, my reliance on and application of the DCF method, the DCF growth rate, and disallowance of his leverage adjustments to the DCF and beta of his CAPM. Further, Mr. Moul disagrees with the appropriate risk-free rate to use and my exclusion of a size adjustment in my CAPM analysis, my disagreement with his

7 UGI Gas Statement No. 6-R, p. 28, lines 1-4.
8 I&E Statement No. 2, p. 17, ln. 5 through p. 18, ln. 13.

use of the Risk Premium (RP) and Comparable Earnings (CE) methods, and my recommended disallowance of additional basis points for management performance. Finally, Mr. Moul opines that the Commission-determined Distribution System Improvement Charge (DSIC) rates should serve as the bare minimum cost of equity in this proceeding.

PROXY GROUP

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR PROXY GROUP.

A. Mr. Moul simply claims that I erroneously omitted New Jersey Resources Corp. and Southwest Gas Holdings, Inc. from my proxy group. He offers no further discussion refuting my reasoning to omit these two companies.[9]

Q. PLEASE REITERATE WHY YOU ELIMINATED NEW JERSEY RESOURCES CORP. AND SOUTHWEST GAS HOLDINGS, INC. FROM YOUR PROXY GROUP.

A. As explained in my direct testimony, both companies, New Jersey Resources Corp. and Southwest Gas Holdings, Inc. were excluded for not meeting my criterion that 50% or more of revenues must be generated from regulated gas utility operations. Again, this criterion is important because revenues represent the percentage of cash flow a company receives from each business line related to

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[9] UGI Gas Statement No. 6-R, p. 2, lines 11-13.

providing a good or service. If less than 50% of revenues come from the gas distribution sector, the companies are not comparable to the subject utility as they do not provide a similar level of regulated business.[10]

Q. DO YOU HAVE ANY CHANGES TO YOUR PROXY GROUP?

A. No. For the reasons discussed above, the percentage of revenue is an appropriate criterion. As New Jersey Resources Corp. and Southwest Gas Holdings, Inc. include an insufficient percentage of regulated gas revenues, they should not be included in the proxy group and compared to UGI Gas.

<u>DISCOUNTED CASH FLOW</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR DCF ANALYSIS.

A. Mr. Moul agrees that results of a DCF analysis should be given weight, but he asserts that use of multiple methods provides a superior foundation to determine the cost of equity. He compares the DSIC rate determined by the Commission in the Quarterly Earnings Summary Reports to the rates calculated using market data. He further disagrees with my results based on the outcomes of certain individual companies and disputes my growth rate analysis. Finally, Mr. Moul disagrees with my recommendation to reject his leverage adjustment.[11]

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[10] I&E Statement No. 2, p. 9, lines 1-12.
[11] UGI Gas Statement No. 6-R, p. 13, ln. 11 through p. 23, ln. 6.

EXCLUSIVE USE OF THE DCF

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR USE OF THE DCF.

A. Mr. Moul asserts that the use of more than one method provides a superior foundation for the cost of equity determination. He claims that the use of more than one method will capture the multiplicity of factors that motivate investors to commit their capital to a particular enterprise.[12]

Q. WERE ANY METHODS OTHER THAN THE DCF EMPLOYED IN YOUR ANALYSIS?

A. Yes. Although my recommendation was based on the results of my DCF analysis, I also employed the CAPM as a comparison. For the reasons discussed in my direct testimony, the DCF method is the most reliable.[13] Although no one method can capture every factor that influences an investor, including the results of methods less reliable than the DCF does not make the end result more reliable or more accurate. In direct testimony, I cited several cases that illustrate the methodology I employed is consistent with the methodology historically used by the Commission in base rate proceedings as recently as 2017, 2018, 2020, and 2021.[14]

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[12] UGI Gas Statement No. 6-R, p. 13, lines 15-20.
[13] I&E Statement No. 2, p. 16, ln. 1 through p. 17, ln. 3.
[14] I&E Statement No. 2, p. 15, lines 11-17.

Q. ARE THERE ANY RECENT COMMISSION ORDERS THAT DEVIATE FROM THIS PRACTICE?

A. Yes. The Commission recently indicated in the 2022 Aqua Pennsylvania, Inc. (Aqua) rate case order that its method "for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies"[15] and that "I&E's DCF and CAPM produce a range of reasonableness for the ROE…"[16], thus deviating from prior Commission practice.

Q. SHOULD THE COMMISSION'S USE OF THE CAPM AS A CEILING FOR A "RANGE OF REASONABLENESS" APPLY IN THIS INSTANT PROCEEDING?

A. No. In my direct testimony I explain more fully why the CAPM should not be used as a primary method and continue to express those concerns in this proceeding as to why it should only be used as a comparison to, not a check of the DCF. Thus, I disagree with a method that provides the CAPM comparable weight to the DCF method.[17]

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15 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 154 (Order entered May 16, 2022).

16 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

17 I&E Statement No. 2, p. 17, ln. 5 through p. 18, ln. 13.

<u>DSIC RATES</u>

Q. SHOULD THE COMMISSION CONSIDER THE AUTHORIZED DSIC RATE ESTABLISHED IN THE QUARTERLY EARNINGS SUMMARY REPORTS AS AN APPROPRIATE MEASURE TO DETERMINE THE COST OF EQUITY IN THIS PROCEEDING?

A. No. Mr. Moul's comparison between the I&E recommended return on equity in this proceeding and the Company's DSIC rate is misguided. My understanding is that the DSIC rate is designed to encourage its use and to incentivize accelerated pipeline replacement and infrastructure upgrades to bring aging infrastructure closer to meeting safety and reliability requirements in between base rate filings. To suggest the cost of equity must be at or above the DSIC rate in this base rate proceeding is inappropriate and not in the public interest. Additionally, the DSIC rate establishes a benchmark above which a utility company is considered "overearning" for use of the DSIC mechanism. As such, the DSIC rate should not serve as a proper measurement of a subject utility's cost of equity in a base rate proceeding since the DSIC rate is routinely higher than any return on equity approved in such base rate proceedings. In fact, 66 Pa. C.S. § 1358(b)(3) states the following:

> The distribution system improvement charge shall be reset at zero if, in any quarter, data filed with the commission in the utility's most recent annual or quarterly earnings report show that the utility will earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the distribution system improvement charge.

Finally, the DSIC mechanism serves to lower a utility's risk because it reduces the lag time in the recovery of a company's capital outlays. DSIC spending requires preapproval of eligible plant via a Long-Term Infrastructure Improvement Plan so there is little question as to the prudence of those expenditures.

Q. ARE THERE ANY INSTANCES YOU ARE AWARE OF WHERE THE COMMISSION GRANTED A RETURN ON EQUITY THAT WAS HIGHER THAN THE MOST RECENTLY PUBLISHED DSIC RATE?

A. Yes. In the recent Aqua base rate case the Commission awarded that company a return on equity of 10.00%,[18] which was higher than the most recently published DSIC rate for water and wastewater utilities of 9.80%.[19] While this report is based on a period ended September 30, 2021, this DSIC rate is still in effect as the Commission has published no DSIC rates since this report was made public in January 2022.

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18 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

19 PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended September 30, 2021, approved at Public Meeting on January 13, 2022 at Docket No. M-2021-3030045.

Q. ARE THERE ANY POTENTIAL PROBLEMS WITH AWARDING A RETURN ON EQUITY THAT IS EQUAL TO OR HIGHER THAN THE DSIC RATE?

A. Yes. First off, it removes incentive for utilities to use the DSIC mechanism between rate filings and may encourage the more frequent filing of base rate cases. Secondly, it may encourage litigation as opposed to settlement of cases, since companies may improperly believe this is the new norm. And finally, it may set companies up to quickly land in an over-earnings status and preclude them from being able to utilize the DSIC mechanism at all.

Therefore, in my opinion, the DSIC rate should generally be an incentive rate that is higher than a return on equity percentage granted in a rate proceeding, and I am anticipating that the recent Commission decision is not indicative of "the new normal."

Q. WERE THERE ANY SPECIAL CIRCUMSTANCES THAT CAUSED THE COMMISSION'S GRANTED RETURN ON EQUITY TO EXCEED THAT OF THE MOST RECENTLY AVAILABLE DSIC RATE FOR AQUA?

A. Yes. The Commission granted 25 basis points for management effectiveness,[20] which caused the return on equity of 9.75% to go up to 10.00% thereby exceeding

[20] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

the currently effective DSIC rate of 9.80% for water and wastewater. I will address management performance is a separate section of testimony below.

EVALUATING THE DCF BASED ON INDIVIDUAL RESULTS

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY REGARDING THE RESULTS OF YOUR DCF.

A. Mr. Moul explains that when some results are unreasonable on their face, the reliability of or the witness' application of that method must be questioned. He points to the results of two companies in my proxy group and claims that they fall into the category of unreasonableness. Mr. Moul attempts to support his theory by arguing that the spread between the cost of debt and the cost of equity is 6.75%.[21]

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S ATTEMPT TO DISAGGREGATE YOUR RESULTS?

A. Mr. Moul derives his suggested 6.75% spread from his RP analysis.[22] However, I have refuted the use of the RP method both in my direct testimony,[23] and later in this testimony, as it is an inferior method for calculating the cost of common equity. Further, the 9.92% result of my DCF analysis offers a 5.62% margin over the undisputed 4.30% updated cost of debt (9.92% - 4.30% = 5.62%). My recommended cost of equity is more than double, or 231% higher that the

[21] UGI Gas Statement No. 6-R, p. 15, ln. 16 through p. 16, ln. 7.
[22] UGI Gas Statement No. 6, p. 41, lines 10-12.
[23] I&E Statement No. 2, p. 13, ln. 7 through p. 19, ln. 6.

Company's cost of debt, which I certainly believe satisfies Mr. Moul's statement that, "It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with a common equity investment."[24]

GROWTH RATE

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR GROWTH RATES.

A. Mr. Moul argues that I should have removed the "unduly low" growth rate of One Gas Inc. from my proxy group average. He suggests that had I done this and excluded One Gas Inc.'s accompanying dividend yield from my analysis, my DCF result would have increased from 9.92% to 10.23% (3.39% dividend yield + 6.84% growth rate).[25]

Q. DO YOU AGREE WITH MR. MOUL'S RECALCULATION OF YOUR DCF RESULTS BASED ON THE REMOVAL OF ONE GAS INC. DUE TO WHAT HE DEEMS TO BE AN UNREASONABLY LOW GROWTH RATE?

A. No. Mr. Moul removes this company from my analysis simply because he believes its growth rate and corresponding DCF result are too low. His

[24] UGI Gas Statement No. 6-R, p. 15, ln. 22 through p. 16, ln. 2.
[25] UGI Gas Statement No. 6-R, p. 17, lines. 5-15.

recalculation results in a DCF that is 31 basis points (10.23% - 9.92%) higher than my recommendation, yet still 97 basis points (11.20% - 10.23%) below his cost of equity recommendation.

Mr. Moul's decision to remove One Gas Inc. only serves to inflate the DCF result as his argument lacks objective rationale and defeats the purpose of using a proxy group. Mr. Moul himself states, "The principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any abnormalities".[26] This acknowledgement is counterintuitive to his suggestion to remove One Gas Inc. from my analysis. Ironically, and worth noting, Mr. Moul employs One Gas Inc. in his own proxy group and analysis.

<u>LEVERAGE ADJUSTMENT</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING HIS LEVERAGE ADJUSTMENT.

A. First, Mr. Moul states that credit rating agencies do not measure the market-required cost of equity for a company, nor are they concerned with how it is applied in the rate-setting context. Rather, the credit rating agencies are only concerned with the interests of lenders and the timely payment of principal and interest by companies. Then, Mr. Moul questions my references to prior

[26] UGI Gas Statement No. 6-R, p. 15, lines 16-18.

Commission orders. Finally, Mr. Moul disagrees with my claim that investors base their decisions on the book value of a company's debt and equity.[27]

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S REBUTTAL TESTIMONY CONCERNING CREDIT RATING AGENCIES?

A. Mr. Moul has actually supported my argument that his proposed leverage adjustment is not needed by stating that the credit rating agencies are only concerned with the timely payment of principal and interest by utilities. Mr. Moul's stated need for the leverage adjustment is based on his assertion that the difference between the book value capital structure and his market value capital structure poses a financial risk difference.[28]

Financial risk does relate to the capital structure of a company, but it is created by the financing decisions (the use of debt or equity) and the amount of leverage or debt with which a company chooses to finance its assets. Financial risk and the book value capital structure of a company are represented in the financial statements, which are part of what is evaluated by rating agencies. Mr. Moul agrees with me that credit rating agencies use a company's booked debt obligations, found in the financial statements, in their analysis to assess financial risk and determine creditworthiness.[29]

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[27] UGI Gas Statement No. 6-R, p. 20, ln. 16 through p. 22, ln. 19.
[28] UGI Gas Statement No. 6, p. 33, lines 3-10.
[29] UGI Gas Statement No. 6-R, p. 20, lines 17-20.

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY ON YOUR REFERENCE TO PRIOR COMMISSION ORDERS.

A. Mr. Moul refers to the discussion in my direct testimony about five recent cases where the Commission has rejected a "leverage adjustment." He explains that even though the Commission declined to make a "leverage adjustment" in a prior Aqua Pennsylvania case, it does not invalidate its use. Further, he states, "Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance."[30] Next, Mr. Moul claims that the adjustment proposed in the City of Lancaster case was much different than what he proposes in this case. Then, regarding UGI Electric, Mr. Moul acknowledges the Commission granted a "management performance increment," not a leverage adjustment when arriving at the allowed equity return. As for the Columbia Gas case, Mr. Moul concedes that the Company accepted I&E's return on equity recommendation which did not include a leverage adjustment or addition of points for management performance. Finally regarding the PECO Gas case, he argues that the Commission arrived at an equity return on the higher side without a leverage adjustment, therefore no adjustment was warranted.[31]

[30] UGI Gas Statement No. 6-R, p. 21, lines 6-8.
[31] UGI Gas Statement No. 6-R, p. 21, lines 1-26.

Q. WHAT IS YOUR RESPONSE TO MR. MOUL REGARDING THE REFERENCED PRIOR COMMISSION ORDERS IN YOUR DIRECT TESTIMONY?

A. In this proceeding, Mr. Moul is recommending a 95-basis point "leverage adjustment." To be clear, the Commission did in fact refuse to accept the leverage adjustment in the Aqua case by stating "…we reject the ALJ's recommendation to allow a 65 basis point leverage adjustment."[32] The management performance points awarded to Aqua were case-specific and in no way related to the proposed leverage adjustment. Regarding the City of Lancaster case, the Commission did not reject the leverage adjustment based on the manner in which it was calculated, but rather, the Commission stated, "…the ALJ's recommendation is in error as any adjustment to the results of the market based DCF as we have previously adopted are unnecessary and will harm ratepayers."[33] Regarding the UGI Electric case, the Commission concluded that "…an artificial adjustment in this proceeding is unnecessary and contrary to the public interest. Accordingly, we decline to include a leverage adjustment in our calculation of the DCF cost of equity."[34] Regarding the most recent Columbia Gas case, the Commission stated,

> … we have adopted the ALJ's recommendation to use I&E's DCF methodology utilizing I&E's dividend yield of 3.34% and growth rate of 6.52%. As noted above, the ALJ did not specify a recommended cost of equity for Columbia in their

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[32] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket No. R-00072711, pp. 38-39 (Order entered July 31, 2008).

[33] *Pa. PUC v. City of Lancaster – Bureau of Water*; Docket No. R-2010-2179103, p. 101 (Order entered July 14, 2011).

[34] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058, pp. 93-94 (Order entered October 25, 2018).

> Recommended Decision. However, we note that I&E's methodology results in an ROE of 9.86%.[35]

The ALJ's Recommended Decision stated the following:

> The ALJ agrees with BIE's reasoning that Columbia Gas' calculated return on equity was flawed for five reasons: (1) the weights given to the results of the Company's CAPM, RP, and CE analyses; (2) certain aspects of Columbia's discussion of risk; (3) Columbia Gas' application of the DCF including the forecasted growth rate and leverage adjustment used; (4) Columbia's inclusion of a size adjustment, reliance on the 30-year Treasury Bond for the risk- free rate, and the use of a double-adjusted *beta* in the CAPM analysis; and (5) the Company's request for an additional 20 basis points for "strong management performance" is unjustified.[36]

While the Company accepted I&E's DCF return without regard to the leverage adjustment or management performance in the last base rate case, in the Recommended Decision, the ALJ clearly rejected the Company's proposed leverage adjustment and the Commission agreed with the ALJ's Recommended Decision.

Finally, in the PECO Energy – Gas Division case, the Commission stated,

> … we have adopted the ALJ's recommendation to use I&E's DCF methodology and to use I&E's CAPM calculation as a check on the reasonableness of the DCF determined cost of equity. Therefore, we shall adopt the ALJ's recommended 10.24% cost of equity. In our view, this is an appropriate cost of equity for PECO given the record developed in this proceeding.[37]

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[35] *Pa. PUC v. Columbia Gas of Pennsylvania*; Inc. Docket No. R-2020-3018835, p. 141 (Order entered February 19, 2021).

[36] *Pa. PUC v. Columbia Gas of Pennsylvania*; Inc. Docket No. R-2020-3018835, Recommended Decision, pp. 184-185.

[37] *Pa. PUC v. PECO Energy Company – Gas Division*. Docket No. R-2020-3018929, p. 171 (Order entered June 22, 2021).

In the Recommended Decision, the ALJ agreed with I&E's recommended cost of equity which did not include a leverage adjustment.[38]

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S ASSERTION THAT INVESTORS DO NOT BASE THEIR DECISIONS ON BOOK VALUE, BUT RATHER THE RETURN THEY EXPECT TO EARN ON THE DOLLARS THEY INVEST?

A. Investors purchase securities such as stocks at market value as opposed to book value. In doing so, they accept the returns and associated risks implied by market prices. However, financial statements, which are based on book values, show the entire true financial position of a company which provide the foundation for investment and financing decisions. For example, financial institutions such as banks lend money based on actual book values and not the current price of a stock. Further, almost all financial ratios used in financial analysis utilize at least one book value variable from either the income statement or the balance sheet.

Mr. Moul's assertion that investors are unconcerned with the book value debt or "some accounting value of little relevance to them"[39] of a utility is unsupported. Clearly an investor takes the financial risk of the utility into consideration when determining a required return. In addition, the market capitalization information included in Value Line's reports and discussed by Mr.

[38] *Pa. PUC v. PECO Energy Company – Gas Division*. Docket No. R-2020-3018929, Recommended Decision, p. 215.

[39] UGI Gas Statement No. 6-R, p. 22, lines 11-13.

Moul is not the same as market value capital structure. Market capitalization refers to the number of shares outstanding multiplied by the current price. A market value capital structure refers to the ratio of market debt to market equity, which, to my knowledge, is not included in Value Line's reports. Therefore, Mr. Moul's contention that Value Line includes market capitalization data does not offer any support for his leverage adjustment.

Q. HAS YOUR RECOMMENDATION CHANGED FROM DIRECT TESTIMONY REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT?

A. No. For the reasons discussed above, I continue to recommend that Mr. Moul's 95-basis point leverage adjustment be rejected.

<u>INFLATION</u>

Q. DOES THE DCF ADEQUATELY FACTOR IN RECENT INFLATIONARY TRENDS?

A. Yes. My DCF calculation includes a spot stock price when determining the dividend yield and analysts who generate forecasted earnings growth rates almost certainly take inflation into consideration as well, therefore, it contains the most up-to-date projected information of any model. Therefore, Mr. Brown's assertion that "the Commission should consider the overall economic climate and these inflationary pressures…when deciding the merits of the Company's requested base rate increase,"[40] are adequately covered by use of the DCF as a primary model for determining an appropriate return on equity.

CAPITAL ASSET PRICING MODEL

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR APPLICATION OF THE CAPM.

A. Mr. Moul opines that my CAPM analysis understates the cost of equity for a few reasons, including my use of the yield on 10-year Treasury Notes for my risk-free rate, failure to use leverage adjusted betas, and rejection of his size adjustment.[41] Each of these topics are discussed in more detail below.

RISK-FREE RATE

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR USE OF THE YIELD ON THE 10-YEAR U.S. TREASURY NOTE.

A. Mr. Moul claims that by using the 10-year Treasury Note, I introduced a systematic understatement of CAPM returns that can be traced to extraordinary monetary policy actions to deal with the recession created by the pandemic. He opines that his use of the yield on a 30-year U.S. Treasury Bond is more appropriate than my use of the yield on a 10-year Treasury Note because 30-year

[40] UGI Gas Statement No. 1-R, p. 6.
[41] UGI Gas Statement No. 6-R, p. 23, lines 10-12.

bonds are "more a reflection of investor sentiment of their required returns…" and are also less susceptible to Federal policy actions.[42]

Q. DO YOU AGREE WITH MR. MOUL THAT USING THE YIELD OF A 30-YEAR U.S. TREASURY BOND IS MORE APPROPRIATE DUE TO A LONGER-TERM BOND BEING LESS SUSCEPTIBLE TO FEDERAL POLICY ACTIONS?

A. No. As explained in my direct testimony,[43] I chose the 10-year Treasury Note as it balances the short-comings of the short-term T-Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with the market risk. In addition, long-term treasury bonds bear the risk of unexpected inflation. As such, my choice of a 10-year Treasury Note is more appropriate. Additionally, as mentioned in my direct testimony, the Commission has recently agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[44]

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42 UGI Gas Statement No. 6-R, p. 23, ln. 24 through p. 24, ln. 10.
43 I&E Statement No. 2, p. 23, ln. 12 through p. 24, ln. 2.
44 *Pa. PUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058, p. 99 (Order entered October 25, 2018).

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR CALCULATION OF THE RISK-FREE RATE USED IN THE CAPM FORMULA.

A. Mr. Moul opines that I have incorrectly given the same weight to the yield on the 10-year Treasury Note for the second quarter of 2022 as I do for the entire five-year period encompassing 2023 to 2027. He then recalculates the risk-free rate by averaging the 10-year Treasury yield forecasts by year from 2022 through 2027 to increase my calculated risk-free rate of 2.35% to 2.80%.[45]

Q. DO YOU AGREE WITH MR. MOUL'S ANALYSIS OF YOUR RISK-FREE RATE?

A. No. Mr. Moul's new calculation proposes to give equal weight to each separate year from 2022 to 2027. The flaw with this approach is that the further out into the future one forecasts, the less reliable and more speculative the estimates become; therefore, to give the less reliable estimates equal weight would not be sensible. It is more appropriate to weight the quarters and years as I have done in my direct testimony.[46] My calculation provides a more accurate estimation of the risk-free rate during the FPFTY, as the further out one forecasts, the less reliable the information becomes.

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45 UGI Gas Statement No. 6-R, p. 24, ln. 11 through p. 25, ln. 1.
46 I&E Exhibit No. 2, Schedule 8.

<u>LEVERAGED ADJUSTED BETAS</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE USE OF LEVERAGED ADJUSTED BETAS.

A. Mr. Moul simply claims that I failed to use leveraged adjusted betas.[47] He does not offer an explanation beyond what he argued in his direct testimony.

Q. IS THE USE OF "LEVERAGED ADJUSTED BETAS" IN CAPM ANALYSIS APPROPRIATE?

A. No. Mr. Moul's adjustment only serves to inflate the result of his CAPM analysis which I have discussed in greater detail in my direct testimony.[48] <u>Value Line</u> is a well-known and trusted source that both investors and the Commission rely upon, therefore, it is not necessary to make any type of adjustment to the <u>Value Line</u> betas.

<u>SIZE ADJUSTMENT</u>

Q. SUMMARIZE YOUR DIRECT TESTIMONY REGARDING A SIZE ADJUSTMENT.

A. In direct testimony, I stated that Mr. Moul's 102-basis point CAPM size adjustment is unnecessary because none of the technical literature he cited in his direct testimony supporting investment adjustments related to the size of a

[47] UGI Gas Statement No. 6-R, p. 23, lines 11-12.
[48] I&E Statement No. 2, p. 43, ln. 23 through p. 44, ln. 16.

company is specific to the utility industry. In addition, I presented an article by Dr. Annie Wong that demonstrates there is no need to make an adjustment for the size of a company in utility rate regulation. Further, I noted that the Commission has recently rejected the application of a size adjustment to the CAPM cost of equity calculation where it agreed that the same literature the Company cites is not specific to the utility industry.[49]

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY REGARDING A SIZE ADJUSTMENT.

A. Mr. Moul states that enormous changes have occurred in the industry since the article "Utility Stocks and the Size Effect: An Empirical Analysis" by Dr. Annie Wong was published. He also references the Fama/French study, "The Cross-Section of Expected Stock Returns," to illustrate that his size adjustment is a separate factor from beta that helps explain systematic risk and returns. Additionally, Mr. Moul opines that external factors, such as loss of larger customers and unexpected changes in expenses, can affect the financial performance of a small company. Finally, he acknowledges that in the 2020 PECO Energy – Gas Division rate case (at Docket No. R-2020-3018929), both the ALJs and the Commission determined that an adjustment for size was not necessary in utility rate regulation.[50]

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[49] I&E Statement No. 2, p. 45, ln. 5 through p. 46, ln. 3.
[50] UGI Gas Statement No. 6-R, p. 25, ln. 6 through p. 27, ln. 3.

Q. DOES THE TIME WHICH HAS ELAPSED SINCE AN ARTICLE WAS WRITTEN NECESSARILY INVALIDATE ITS RESULTS?

A. No. Although Mr. Moul states that enormous changes have occurred in the industry since the 1960s, he presents no evidence that these "changes" have caused the need for a size adjustment. To the contrary, Dr. Wong's study demonstrated that one does *not* need to be made in the regulated utility industry. As stated in my direct testimony, absent any credible article to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected.

Q. DOES THE FAMA/FRENCH STUDY REFUTE DR. WONG'S ARTICLE?

A. No. As stated in my direct testimony, Dr. Wong's article presents evidence that although a size effect may exist for industrial stocks, it does not exist for utility stocks. As the Fama/French study is not specific to utility stocks, it does not demonstrate that a size effect exists in the utility industry. In addition, the size effect that exists for industrial stocks varies to such an extent that it is difficult to predict. The difficulty in predicting the effect of size is demonstrated in the variance from year to year of the measurement of difference between the annual returns on the large and small-capitalization stocks of the NYSE/AMEX/NASDAQ in the Ibbotson *Stocks, Bonds, Bills & Inflation: 2015 Yearbook*. As stated on page 100 of the SBBI Yearbook,

> While the largest stocks actually declined in 2001, the smallest stocks rose more than 30%. A more extreme case occurred in the depression-recovery year of 1933, when the difference between the first and 10th decile returns was far more

> substantial. The divergence in the performance of small- and large- cap stocks is evident. In 30 of the 89 years since 1926, the difference between the total returns of the largest stocks (decile 1) and the smallest stocks (decile 10) has been greater than 25 percentage points.

Page 109 states,

> In four of the last 10 years, large-capitalization stocks (deciles 1-2 of NYSE/AMEX/NASDAQ) have outperformed small-capitalization stocks (deciles 9-10). This has led some market observers to speculate that there is no size premium. But statistical evidence suggests that periods of underperformance should be expected.

Page 112 states,

> Because investors cannot predict when small-cap returns will be higher than large-cap returns, it has been argued that they do not expect higher rates of return for small stocks.

Q. ARE MR. MOUL'S CONCERNS REGARDING THE IMPACT OF LOSING LARGE CUSTOMERS OR UNEXPECTED INCREASES IN EXPENSES VALID?

A. No. Regulated utility companies have the option to file a base rate case to address declining revenues and to recover the increasing costs of doing business in addition to emergency rate relief provisions for large unforeseen impacts. In contrast, non-utility businesses that may be significantly impacted by events of this nature due to small operating size do not have these opportunities. Further, while a smaller utility may pay higher prices for services and materials just due to volume buying power, the actual costs are part of the revenue requirement presented by that company, so to increase the return to account for the potential size disadvantage would only further unfairly burden ratepayers who are already likely paying higher utility bills to recover the higher operating costs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. MOUL'S SIZE ADJUSTMENT?

A. I continue to recommend that his use of the 1.02% size adjustment be disallowed in calculating the CAPM.

Q. MR. MOUL HAS RECALCULATED YOUR CAPM RESULTS.[51] DO YOU AGREE WITH HIS RECALCULATION?

A. No. Mr. Moul's recalculation is incorrect for a couple of reasons. As stated in both my direct testimony and above, he used an inaccurate risk-free rate and an unnecessary size adjustment. Because of these factors, the recalculation of my CAPM results as Mr. Moul illustrates is unreliable and unnecessary.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR CAPM ANALYSIS?

A. Yes. My recommend cost of equity is primarily based upon my DCF analysis for the reasons explain above and in my direct testimony. I present a CAPM analysis to the Commission for comparison, not recommendation purposes as the inputs are highly subjective, and other than beta, not company or industry specific. Again, it

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[51] UGI Gas Statement No. 6-R, p. 25, lines 2-5.

has traditionally been the preference of the Commission to view both the DCF and CAPM analysis in base rate proceedings.

INFLATION

Q. IS IT NECESSARY TO EMPLOY THE CAPM WITH EQUAL WEIGHT TO THE DCF WHEN DETERMINING A SPECIFIC RETURN ON EQUITY DUE TO RECENT INFLATIONARY TRENDS?

A. No. My use of the DCF as a primary method in determining an appropriate return on equity sufficiently takes this into consideration. As mentioned above, the DCF includes a spot stock price in the dividend yield calculation and analysts who generate forecasted earnings growth almost certainly take inflation into consideration as well, so it contains the most up-to-date projected information of any model. In other words, the inputs of the DCF capture all known economic factors, including inflation.

RISK PREMIUM

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE RISK PREMIUM METHOD.

A. Mr. Moul opines that the RP approach should be given serious consideration because it is straight-forward, understandable, and uses a company's own borrowing rate. He claims it provides a direct and complete reflection of a utility's risk and return. Mr. Moul also states that I make an unfounded assertion that the RP method does not measure the current cost of equity as directly as the DCF.[52]

Q. DO YOU AGREE WITH MR. MOUL THAT THE RP METHOD PROVIDES A DIRECT AND COMPLETE REFLECTION OF A UTILITY'S RISK AND RETURN?

A. No. The RP method produces an indirect measure when compared to the DCF method.

Q. PLEASE COMMENT ON THE INDIRECT MEASURE OF THE RP METHOD VERSUS THE MORE DIRECT MEASURE OF THE DCF METHOD.

A. Mr. Moul claims my statement, that the Risk Premium method does not measure the current cost of equity as directly as the DCF, is without foundation. In my direct testimony, I have clearly illustrated how the two measures are different.[53] The main reason is that the RP method determines the rate of return on common equity indirectly by observing the cost of debt and adding to it an equity risk premium. The DCF measures equity more directly through the stock information (using equity information), whereas the RP method measures equity indirectly using debt information.

[52] UGI Gas Statement No. 6-R, p. 28, ln. 5 through p. 29, ln. 19.
[53] I&E Statement No. 2, p. 13, ln. 17 through p. 19, ln. 6.

COMPARABLE EARNINGS

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE CE METHOD.

A. Mr. Moul claims that using the CE method satisfies the comparability standard established in the *Hope* case. Additionally, he states, "the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets."[54]

Q. DO YOU BELIEVE THAT THE COMPANIES USED BY MR. MOUL IN HIS CE METHOD ANALYSIS ARE COMPARABLE TO UGI GAS?

A. No. As explained in my direct testimony,[55] the companies in Mr. Moul's analysis are not utilities, and therefore, are too disparate to be used in a CE analysis. For example, the criteria Mr. Moul uses to choose the companies in his CE group results in the selection of companies such as Altria Group Inc. (Tobacco), Bio-Techne Corp. (Biotechnology), CVS Caremark Corp. (Retail/Pharmacy), Intuit Inc, (Computer Software), Monster Beverage Corp. (Beverage), Quest Diagnostics Inc. (Medical Services), Toro Co. (Machinery), and Western Union Co. (Financial Services) just to name few.[56] All these companies operate in industries very different from a utility company and operate under varying degrees of regulation.

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54 UGI Statement No. 6-R, p. 30, lines 5-11.
55 I&E Statement No. 2, p. 26, ln. 13 through p. 27, ln. 5.
56 UGI Gas Exhibit B, Schedule 14.

Also, a large majority, if not all the companies Mr. Moul uses in his analysis, are not monopolies as utilities largely are. This means that they have significantly more competition and would require a higher return for the added risk. Further, the CE method should be excluded because it is entirely subjective as to which companies are comparable and it is debatable whether historical accounting returns are representative of the future.

MANAGEMENT PERFORMANCE POINTS

Q. SUMMARIZE THE COMPANY'S REBUTTAL TESTIMONY REGARDING MANAGEMENT PERFORMANCE POINTS.

A. Mr. Moul continues to advocate for 20 additional basis points to the cost of equity as he believes UGI Gas has performed in an exemplary manner. He points to Mr. Brown's testimony[57] for support.

Mr. Brown acknowledges my position that UGI Gas should not be rewarded for doing what the Company is legally required to do, and that the savings resulting from true management effectiveness are available to be passed on to shareholders. He suggests that I disagree with Pennsylvania law, specifically 66 Pa. C.S. § 523 which gives the Commission the ability to consider management performance. Additionally, he cites to UGI Electric's 2017 rate case where the Commission granted additional basis points for management performance. Mr.

[57] UGI Gas Statement No. 6-R, p. 30, ln. 12 through p. 31, ln. 1.

Brown argues that UGI Gas has similar types of programs to UGI Electric, and he recaps the achievements discussed in his direct testimony.[58]

Q. WHAT IS YOUR RESPONSE TO THE COMPANY'S REBUTTAL TESTIMONY REGARDING THE CONSIDERATION OF ADDITIONAL BASIS POINTS FOR MANAGEMENT PERFORMANCE?

A. As discussed in greater detail in my direct testimony,[59] I maintain that UGI Gas, or any utility company for that matter, should not reap additional rewards for programs funded by ratepayers or for meeting their obligations under 66 Pa C.S.A. §1501.

Also, while I am aware that under 66 Pa C.S.A. §523 the Commission shall consider a utility's performance, it is not mandatory that the Commission grant additional points. Moreover, I continue to assert that for any company, true strong management performance is earning a higher return through its efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to shareholders. Additionally, it is nonsensical to support the idea that since ratepayers fund the initiatives and accomplishments Mr. Brown mentions, ratepayers should then in turn fund a higher equity return for UGI Gas' investors.

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[58] UGI Gas Statement No. 1-R, p. 6, ln. 18 through p. 14, ln. 1.
[59] I&E Statement No. 2, p. 47, ln. 9 through p. 50, ln. 7.

Q. ARE YOU AWARE OF ANY OTHER COMPANIES THAT HAVE RECEIVED ADDITIONAL BASIS POINTS IN RECOGNITION OF MANAGEMENT PERFORMANCE?

A. Yes. Most recently, the Commission awarded Aqua an addition of 25 basis points for its management performance efforts.[60] However, it is important to recognize that this addition was based specifically on Aqua rescuing troubled water and wastewater systems at the Commission's request. In this proceeding, the Commission stated the following: [61]

> We specifically recognize Aqua's efforts and willingness to quickly provide emergency aid to various water and wastewater systems that needed substantial improvement. Aqua has often provided this emergency aid on short notice and at the request of the Commission or other parties to protect the public from egregious health and safety threats and to protect the Commonwealth's drinking water resources from catastrophic damage.

Q. DOES THE COMMISSION'S PAST ISSUANCE OF ADDITIONAL EQUITY POINTS TO RECOGNIZE MANAGEMENT PERFORMANCE MEAN THAT UGI GAS SHOULD ALSO RECEIVE AN ADJUSTED RETURN ON EQUITY?

A. No. The issuance of equity points to recognize management performance must always be done on a case by case basis. The situation in the Aqua case as discussed above was very specific to the Company rescuing troubled water and

[60] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 168-173 (Order entered May 16, 2022).

[61] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, p. 169 (Order entered May 16, 2022).

wastewater systems and preventing health and safety concerns regarding drinking water. This scenario does not apply to UGI Gas. Further, the example Mr. Brown provides, the 2017 UGI Electric rate case, is irrelevant to the determination of whether UGI Gas should be granted additional basis points to its cost of equity for management performance. Management performance is something that is very specific to each individual utility. Therefore, what the Commission has historically decided in this regard, and the management performance of other utilities, has no bearing on whether UGI Gas should receive a higher return on equity to recognize its management performance. Notably however, in the 2017 UGI Electric case, which was decided in a pre-pandemic climate when ratepayers were not faced with the current levels of inflation, the Commission awarded the Company a nominal five additional basis points for management effectiveness. Additionally, since Mr. Brown makes the argument that the management performance of UGI Gas is comparable to that of UGI Electric, the implication that UGI Gas should receive much more than what UGI Electric was awarded is unreasonable.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS CONCERNING THE COMPANY'S CLAIM REGARDING MANAGEMENT PEFORMANCE?

A. Yes. While I am aware of the rising costs of capital due to the after-effects of the pandemic and the increasing levels of inflation, I believe it is important not to over burden ratepayers.

Notably, in recognition of recent inflation, I&E is not disputing the updated increase in the cost of long-term debt as presented above.

Further, my 9.92% recommended cost of equity based on the DCF model is higher than the average Commission-granted return on equity for all natural gas utilities across the country since 2012.[62] In addition, as mentioned in my direct testimony, a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[63] illustrates that UGI Gas' 11.20% requested return on equity is 99 basis points higher (almost one full percentage point higher) than the average return on equity request of 10.21% of all pending gas utility rate cases as of March 10, 2022. So, as the economy is in decline, UGI Gas is requesting a record return on equity to apply to its equity heavy capital structure. It should be noted that strong stock market performance does not always equate to strong economic performance.

Finally, and perhaps most importantly, most of the programs Mr. Brown discusses are ultimately *funded by ratepayers* and any savings resulting from cost cutting measures would likely be offset by the addition of basis points for management performance as ratepayers would have to fund those additional costs as well. This defeats the purpose of efforts to reduce costs to benefit ratepayers.

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[62] https://www.capitaliq.spglobal.com/web/client?auth=inherit&overridecdc=1&#industry/statisticsAndGraphs (Accessed May 24, 2022).

[63] Regulatory Research Associates, "Major energy utility cases in progress in the US, Quarterly update on pending rate cases," *S&P Global Market Intelligence*, March 16, 2022.

Q. HAS YOUR RECOMMENDATION REGARDING THE COMPANY'S REQUEST FOR ADDITIONAL BASIS POINTS FOR MANAGEMENT PERFORMANCE CHANGED?

A. No. I continue to recommend that any additional basis points for management performance be rejected.

<u>OVERALL RATE OF RETURN</u>

Q. HAS YOUR OVERALL RATE OF RETURN RECOMMENDATION CHANGED FROM YOUR DIRECT TESTIMONY?

A. Yes. While I continue to support my calculated 9.92% cost of common equity, I have updated my overall rate of return recommendation to reflect the Company's updated cost of long-term debt.

Q. WHAT IS YOUR OVERALL RATE OF RETURN RECOMMENDATION?

A. I recommend the following rate of return for UGI Gas:

I&E
Summary of Cost of Capital

Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost**
	UGI Utilities, Inc. - Gas Division		
Long-Term Debt	44.88%	4.30%	1.93%
Common Equity	55.12%	9.92%	5.47%
Total	100.00%		7.40%

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 3
Witness: Brian J. LaTorre

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Direct Testimony

of

Brian J. LaTorre

Bureau of Investigation and Enforcement

Concerning:

OPERATING & MAINTENANCE EXPENSES

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Brian LaTorre. I am a Fixed Utility Financial Analyst in the Technical Division of the Pennsylvania Public Utility Commission's (Commission or PUC) Bureau of Investigation and Enforcement (I&E). My business address is Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. My education and professional background are set forth in Appendix A, which is attached.

Q. DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in rate proceedings. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the base rate filing of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) and make recommended adjustments to the Company's proposed operating and maintenance (O&M) expense claims for the fully projected future test year (FPFTY) ending September 30, 2023.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 3 contains schedules that support my direct testimony.

SUMMARY OF RECOMMENDED ADJUSTMENTS

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS AS EXPLAINED IN THIS DIRECT TESTIMONY.

A. The following table summarized my recommended adjustments to the O&M expense claims under my purview. These recommended adjustments are reflected in the overall I&E recommended revenue requirement presented by I&E witness Zachari Walker[1] in this proceeding.

	Company Claim	**Recommended Allowance**	**I&E Adjustment**
O&M Expenses:			
Rate Case Expense	$1,055,000	$633,000	($422,000)
2020 and 2021 Environmental Remediation Expense	$2,327,000	$465,400	($1,861,600)
OSHA/Emergency Temporary Standard Compliance Costs	$1,883,000	$31,760	($1,851,240)
Total O&M Expense Adjustments			**($4,134,840)**

[1] I&E Statement No. 1.

<u>RATE CASE EXPENSE</u>

Q. DESCRIBE THE NATURE AND TYPES OF EXPENDITURES TYPICALLY ALLOWED AS PART OF A REGULATED UTILITY'S OVERALL RATE CASE EXPENSE.

A. The nature and types of individual expenditures that comprise a utility's allowable claim for rate case expense are those directly incurred to compile, present, and defend a utility's request for a rate base increase before the Commission. The actual expenditures and estimated costs typically found in an allowable rate case expense claim include legal fees for outside counsel, fees to outside consultants, and the cost of printing, document assembly, and postage.

Q. HOW HAS THE COMMISSION TRADITIONALLY TREATED RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission has historically stated that it considers prudently incurred rate case expense as an ongoing expense, occurring at irregular intervals, related to the rendering of utility service. Thus, it is necessary to normalize rate case expense for ratemaking purposes. The Commission has also cited the importance of considering the involved utility's history regarding the frequency of rate case filings as an essential element in determining the normalized level of rate case expense for ratemaking purposes.

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is determined by calculating the average number of months between the filing dates of a utility's previous base rate cases.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. The Company's FPFTY claim for rate case expense is $1,055,000.[2]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has estimated a total rate case expense of $1,055,000 and is requesting a normalization period of one year (12 months). In his testimony, UGI Gas witness Christopher R. Brown indicated the Company expects to file its next rate case approximately one year following the filing of this base rate case.[3]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend the Company's rate case expense be normalized over a 20-month period resulting in an annual allowance of $633,000 [($1,055,000 ÷ 20 months) x 12] or a reduction of $422,000 ($1,055,000 - $633,000) to the Company's annual rate case expense claim.

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[2] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-10.

[3] UGI Gas Statement No. 1, pp. 9-10.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. The Company's requested normalization period of one year for rate case expense is not supported by the historic filing frequency of the Company. In response to I&E-RE-46,[4] the Company provided the following information about its last three historic base rate cases:

Docket No.	Filing Date	Filing Interval - Months
R-2021-3030218	1/28/2022	24
R-2019-3015162	1/28/2020	12
R-2018-3006814	1/28/2019	24
R-2016-2580030	1/19/2017	

The Company filed its three most recent rate cases on January 19, 2017; January 28, 2019; and January 28, 2020. Including the current rate case, which was filed on January 28, 2022, the average filing frequency is 20 months [(24 months + 12 months + 24 months) ÷ 3]. The recommended 20-month normalization period is consistent with the Commission's emphasis on the importance of considering the utility's history of rate case filings when determining the normalization period of rate case expenses. A one-year normalization period should be disallowed as it would result in an unreasonable increase in customer rates.

[4] I&E Exhibit No. 3, Schedule 1.

Q. ARE THERE ANY COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION FOR A RATE CASE FILING INTERVAL BASED ON HISTORIC FILING FREQUENCY?

A. Yes. In a base rate case filed by Emporium Water Company, the Commission adopted the I&E-recommended historic filing frequency finding in favor of I&E's recommended five-year normalization period based on historic average filing frequency that was rounded down from 64 months.[5]

Similarly, the Commission agreed with I&E's recommendation in the City of DuBois base rate case to use a historic filing frequency finding in favor of I&E's recommended 64-month normalization period, matching the actual historic filing frequency.[6]

Likewise, in the 2020 Columbia Gas of Pennsylvania, Inc. base rate proceeding, the Commission confirmed the normalization period should align with the historic data rather than the Company's intent to file its next rate case.[7]

Finally, and most recently, the Commission determined that a normalization period based on actual historic filing frequency is more reliable than future speculation in the 2020 PECO Energy Company – Gas Division (PECO Gas) rate case. In the PECO Gas case, the Commission accepted I&E's

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[5] *PA PUC v. Emporium Water Company,* Docket No. R-2014-2402324, pp. 47-50 (Order Entered January 28, 2015).

[6] *PA PUC v. City of DuBois – Bureau of Water,* Docket No. R-2016-2554150, pp. 65-66 (Order Entered March 28, 2017); *PA PUC v. City of DuBois – Bureau of Water,* Docket No. R-2016-2554150, p. 13 (Order Entered May 18, 2017).

[7] *PA PUC v. Columbia Gas,* Docket No. R-2020-3018835, Opinion and Order, pp. 78-79 (Order Entered February 19, 2021).

recommended five-year normalization period in contrast to a claim based on a three-year period.[8]

UNRECOVERED ENVIRONMENTAL REMEDIATION EXPENSE

Q. WHAT ARE THE ENVIRONMENTAL REMEDIATION COSTS ASSOCIATED WITH MANUFACTURED GAS PLANTS (MGPs)?

A. Environmental remediation costs are those costs attributed to the site investigations, remediation, restoration of MGPs, and Pennsylvania Department of Environmental Protection oversight costs. There may also be costs incurred to obtain an environmental covenant at the site to prevent certain uses of the site and miscellaneous costs associated with transferring the site to a third party once the site has been restored.[9] Briefly, remediation costs are expenses for investigation, assessment, site characterization, and clean-up of MGPs.

Q. BRIEFLY SUMMARIZE THE COMPONENTS OF THE COMPANY'S ENVIRONMENTAL REMEDIATION EXPENSE CLAIM.

A. The Company is claiming a current ongoing cash expenditure based on a three-year historic average,[10] it is making a claim for the unrecovered MGP expenses for

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8 *PA PUC v. PECO Energy Company – Gas Division,* Docket No. R-2020-3018929, Opinion and Order, pp. 117-119 (Non-Proprietary Order Entered June 22, 2021).

9 UGI Gas Statement No. 9, pp. 24-25.

10 UGI Gas Statement No. 3, p. 17 and UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-8, Environmental Adjustment #1.

the Fiscal Year 2019 and prior periods,[11] and it is making a claim for under-recovery of environmental expenditures for 2020 and 2021.[12]

Q. WHAT IS UNRECOVERED ENVIRONMENTAL REMEDIATION EXPENSE?

A. This expense represents the Company's amortization of unrecovered environmental remediation costs for MGPs that exceed the annual allowance for the expense amount approved in the prior base rate cases.

Q. WHICH UNRECOVERED ENVIRONMENTAL REMEDIATION EXPENSE CLAIM ARE YOU ADDRESSING HEREIN?

A. I am addressing the proposed amortization of: (1) unrecovered 2019 and prior years' environmental remediation expenses; and (2) unrecovered 2020/2021 environmental remediation expenses.

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[11] UGI Gas Statement No. 3, p. 18 and UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-8, Environmental Adjustment #2.

[12] UGI Gas Statement No. 3, p. 18 and UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-8, Environmental Adjustment #3.

Unrecovered 2019 and Prior Years' Environmental Remediation Expense

Q. WHAT IS THE COMPANY'S CLAIM FOR THE AMORTIZATION OF 2019 AND PRIOR YEARS' UNRECOVERED ENVIRONMENTAL REMEDIATION EXPENSE?

A. The Company is claiming $1,865,000 for the FPFTY.[13]

Q. WHAT IS THE BASIS OF THE COMPANY'S CLAIM?

A. UGI Gas witness Vivian K. Ressler has indicated that in the 2020 rate case, the Company was authorized to amortize $8.103 million of under-recovered expense over five years, resulting in $1.621 million per year for fiscal years prior to September 2018, and it was authorized $1.219 million over five years, or $0.24 million per year for Fiscal Year 2019. Thus, she asserts that the annual amount is $1.865 million per year until the total is fully amortized.[14]

Q. DO YOU ACCEPT THE COMPANY'S CLAIM FOR THE 2019 AND PRIOR YEARS' UNRECOVERED ENVIRONMENTAL REMEDIATION EXPENSE AMORTIZATION?

A. Yes. However, I recommend the Company be required to provide a full line-by-line account of the yearly amortizations in the next base rate proceeding because, based on the explanation provided below, by the time the Company files its next rate case and new rates go into effect in that subsequent proceeding I anticipate

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[13] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-8, Environmental Adjustment #2.
[14] UGI Gas Statement No. 3, p. 18.

that the amounts prior to Fiscal Year 2019 will be fully extinguished and there will be no remaining balance left to recover.

Q. IN WHAT YEAR SHOULD THE AMORTIZATIONS HAVE BEGUN?

A. According to the Commission Orders as cited below, the Company should have begun the amortization on October 1, 2019 for periods prior to September 2019 (for the $1.621 million), and January 1, 2021 for the $0.244 million per year that applies to the Fiscal Year 2019.

Q. WHEN WOULD THOSE AMOUNTS BE FULLY EXTINGUISHED?

A. Based on the following table, the amounts would be fully extinguished as follows:

<u>For Periods Prior to September 2019</u>:[15]
2019 $1.621 million
2020 $1.621 million
2021 $1.621 million
2022 $1.621 million
2023 $1.621 million
(After FPFTY 2023, fully extinguished)

<u>For Fiscal Year 2019</u>:[16]
2021 $0.244 million x 75% (for Jan.-Sep.) or $0.183 million
2022 $0.244 million
2023 $0.244 million
2024 $0.244 million
2025 $0.244 million
2026 $0.244 million x 25% (for Oct.-Dec.) or $0.061 million
(After Dec. 31, 2026, fully extinguished)

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[15] *PA PUC v. UGI Utilities, Inc – Gas Division* Docket No. R-2018-3006814, Order Entered September 19, 2019; Paragraph 64

[16] *PA PUC v. UGI Utilities, Inc – Gas Division* Docket No. R-2019-3015162, Order Entered October 8, 2020; Paragraph 33

Unrecovered 2020/2021 Environmental Remediation Expense

Q. WHAT IS THE COMPANY'S CLAIM FOR AMORTIZATION OF 2020 AND 2021 UNRECOVERED ENVIRONMENTAL REMEDIATION EXPENSE?

A. The Company is claiming amortization of unrecovered 2020 and 2021 environmental remediation expense of $2,327,000 over a period of one year.[17]

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim is based on amortization of the total 2020 and 2021 unrecovered expense related to environmental remediation costs of $2,327,000 over one year, which is also the FPFTY claim.[18]

Q. UPON WHAT DID THE COMPANY BASE ITS PROPOSED ONE-YEAR AMORTIZATION?

A. The Company's claimed one-year amortization for unrecovered 2020/2021 environmental remediation expense is in line with its claimed one-year normalization period for rate case expense.[19]

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[17] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-8, Environmental Adjustment #3.
[18] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-8, line 13-17.
[19] UGI Gas Statement No. 3, p. 18 and UGI Gas Statement No. 1, pp. 9-10.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR THE AMORTIZATION OF 2020 AND 2021 UNRECOVERED ENVIRONMENTAL REMEDIATION EXPENSE?

A. No.

Q. WHAT DO YOU RECOMMEND FOR THE AMORTIZATION OF UNRECOVERED 2020 AND 2021 ENVIRONMENTAL REMEDIATION EXPENSE?

A. I recommend an allowance of $465,400 for unrecovered 2020 and 2021 environmental remediation expense or a reduction of $1,861,600 ($2,327,000 - $465,400) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommended allowance for the amortization of 2020 and 2021 environmental remediation expense is based on an amortization period of five years to remain consistent with the amortization period of five years for unrecovered environmental remediation expense from the Opinion and Order in the prior case.[20] Accordingly, I calculated the FPFTY amortization or the unrecovered expense by applying the amortization period of five years, which produced my recommended allowance of $465,400 ($2,327,000 ÷ 5 years).

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[20] *PA PUC v. UGI Utilities, Inc – Gas Division* Docket No. R-2019-3015162, Order Entered October 8, 2020; Paragraph 33.

This amortization would begin in the FPFTY 2023 and be fully amortized by Fiscal Year 2027.

<u>OSHA/EMERGENCY TEMPORARY STANDARD (ETS) COMPLIANCE COSTS</u>

Q. WHAT ARE OSHA/ETS COMPLIANCE COSTS?

A. OSHA/ETS compliance costs are costs associated with President Biden's COVID-19 Action Plan and the U.S. Department of Labor's OSHA ETS requirements relating to vaccination and testing mandates. These costs include vaccination status tracking, performing required COVID-19 tests, legal assistance, and policy drafting and communication to affected employees and contractors.[21]

Q. WHAT IS THE COMPANY'S CLAIM FOR OSHA/ETS COMPLIANCE COSTS?

A. In its filing, the Company claims a total budget of $1,883,000 as an adjustment to operating expenses in the FPFTY. These costs include $1,692,000 for the tracking of COVID-19 Vaccination Status and performing required testing, and $191,000 in one-time costs for communication and legal costs.[22]

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED OSHA/ETS COMPLIANCE COSTS?

A. The Company proposes amortizing these COVID-19 related costs over a one-year

[21] UGI Gas Statement No. 3, pp. 24-26.
[22] UGI Gas Statement No. 3, p. 25 and UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-13.

period in line with its claimed rate case filing interval.[23] On November 5, 2021, OSHA issued the vaccination and testing ETS for businesses that have over 100 employees. Company witness Ressler acknowledges that there is uncertainty concerning the federal mandates due to a recent decision by the U.S. Supreme Court but asserted that "it is appropriate to include a cost associated with vaccination and testing mandates in its revenue requirement to ensure future cost recovery in the event such mandates or similar mandates become law."[24]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR OSHA/ETS COMPLIANCE COSTS?

A. No.

Q. WHAT DO YOU RECOMMEND FOR OSHA/ETS COMPLIANCE COSTS?

A. I recommend an allowance of $31,760 for amortization of deferred COVID-19 related OSHA/ETS compliance costs or a reduction of $1,851,240 ($1,883,000 - $31,760) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. In response to OCA-III-25,[25] the Company states that it is withdrawing a majority

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[23] UGI Gas Book V, Exhibit A – Fully Projected, Schedule D-13.
[24] UGI Gas Statement No. 3, p. 25.
[25] I&E Exhibit No. 3, Schedule 2.

of the claim because the U.S. Supreme Court overturned the Federal Mandate. However, the Company is still claiming $52,934 on already incurred costs and is requesting to amortize this cost over a one-year period. These are costs that were associated with legal advice related to the application of the mandate, and a subscription to a vaccine tracking software.

While I accept that these COVID-19 related costs are already incurred, I recommend an amortization period of 20 months in line with my recommended rate case filing frequency for rate case expense as explained above. This would minimize any over- or under-recovery of the related cost. Therefore, I recommend an allowance of $31,760 [($52,934 ÷ 20 months) x 12].

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Brian LaTorre

Professional and Educational Background

Professional Experience

Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
November 2021 to Present
Fixed Utility Financial Analyst, Bureau of Investigation and Enforcement

Pennsylvania House of Representatives, Lansdale, Pennsylvania
December 2018 to October 2021
Constituent Services Advisor
Organized meetings with local officials and stakeholders on issues impacting the community. Assisted residents and business owners with issues relating to state government, including LIHEAP and Unemployment Compensation.

SimiTree Healthcare Consulting, Conshohocken, Pennsylvania
June 2016 to March 2018
Analyst
Tracked and analyzed revenue cycle accounts receivable trends for home healthcare and hospice clients. Identified and corrected Medicare, Medicaid, and Private Insurance billing issues. Maintained external dashboards that displayed key performance indicators for clients.

Education and Training

Pennsylvania State University – Smeal College of Business
Bachelor of Science, Finance, 2016
Minor in Economics

PUC Rate School, January 18 through February 8, 2022

Testimony Submitted

- R-2022-3030235 – National Fuel Gas Distribution Corporation (§ 1307(f))

I&E Statement No. 3-SR
Witness: Brian J. LaTorre

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Surrebuttal Testimony

of

Brian J. LaTorre

Bureau of Investigation and Enforcement

Concerning:

OPERATING & MAINTENANCE EXPENSES

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brian LaTorre. My business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation and Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME BRIAN LATORRE WHO SUBMITTED TESTIMONY IN I&E STATEMENT NO 3. AND I&E EXHIBIT NO. 3?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of UGI Utilities, Inc. – Gas Division (UGI Gas or Company) witnesses Tracy A. Hazenstab (UGI Statement No. 2-R), and Vivian K. Ressler (UGI Statement No. 3-R).

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. No. However, I do refer to my direct testimony.[1]

SUMMARY OF RECOMMENDED ADJUSTMENTS

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS AS EXPLAINED IN THIS SURREBUTTAL TESTIMONY.

A. The following table summarizes my updated recommended adjustments to the O&M expense claims under my purview. These recommended adjustments are reflected in the overall I&E recommended revenue requirement presented by I&E witness Zachari Walker[2] in this proceeding.

	Updated Company Claim	**Updated I&E Recommended Allowance**	**I&E Adjustment**
O&M Expenses:			
Rate Case Expense	$1,055,000	$633,000	($422,000)
2020 and 2021 Environmental Remediation Expense	$2,327,000	$1,396,200	($930,800)
OSHA/Emergency Temporary Standard Compliance Costs	$52,934	$31,760	($21,174)
Total O&M Expense Adjustments			**($1,373,974)**

RATE CASE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR RATE CASE EXPENSE.

A. I recommended that the Company's rate case expense be normalized over a period

[1] I&E Statement No. 3.

[2] I&E Statement No. 1-SR.

of 20 months, resulting in an annual expense of $633,000 [($1,055,000 ÷ 20 months) x 12 months], or a reduction of $422,000 ($1,055,000 - $633,000) to the Company's claim. My recommendation was based on the Company's base rate case filing history since 2017 [3] in contrast to the Company's claimed one-year normalization period, which is based on when the Company expects to file its next rate case.[4]

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company witness Tracy A. Hazenstab[5] responded to my recommendation for rate case expense.

Q. SUMMARIZE MS. HAZENSTAB'S RESPONSE.

A. Ms. Hazenstab disagrees with using historical base rate case frequency as a predictor of the frequency of future base rate cases. Ms. Hazenstab opines that the Company's expectation that it will file another base rate case in a year is based upon an assessment of future capital requirements and system improvements as outlined in the Company's Long-Term Infrastructure Improvement Plan (LTIIP), in addition to rising inflation, capital cost rates, and a higher risk associated with the rate of return. Additionally, Ms. Hazenstab states that the Columbia Gas 2020

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3 I&E Statement No. 3, pp. 4-5.
4 UGI Gas Statement No. 1, pp. 9-10.
5 UGI Gas Statement No. 2-R, p. 9.

and PECO Gas 2021 cases I cited in my direct testimony are distinguishable from the instant case due to circumstances surrounding the COVID-19 pandemic.[6] Finally, Ms. Hazenstab refutes my calculation of the frequency of past base rate cases, arguing that the Company's most recent base rate proceeding was subject to a one-year settlement stay-out clause that prohibited the Company from making a base rate filing until January 2, 2022, which added a year to the period the UGI Gas could not make a filing.

Q. WHAT OTHER UTILITY DID MS. HAZENSTAB REFERENCE THAT RECEIVED APPROVAL FOR A NORMALIZATION PERIOD BASED ON SPECULATION OF A FUTURE FILING?

A. In her rebuttal testimony, Ms. Hazenstab states that I disregarded the fact that the reliance upon historic rate case filing frequency was rejected by the Commission in Pa. PUC v. UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058 (Order entered Oct. 25, 2018) (UGI Electric 2018). In UGI Electric 2018*,* I&E recommended a five-year normalization period based on historic filing frequency as opposed to UGI Electric's three-year normalization period based on speculation of a future base rate filing. In UGI Electric 2018, UGI Electric had last filed a rate case in 1996, 22 years prior. In addition, UGI Electric had its LTIIP approved

[6] UGI Gas Statement No. 2-R, p. 9-11.

between the 1996 rate case and the 2018 rate case, which significantly increased capital spending.

Q. HOW DOES THE UGI ELECTRIC 2018 FILING DIFFER FROM THE INSTANT PROCEEDING?

A. UGI Gas has a more frequent and recent filing history, which provides more support for the use of historic filing frequency. Additionally, UGI Gas had already been subject to its second LTIIP at the time of its last proceeding.[7] These two factors distinguish UGI Electric 2018 from the instant case. Thus, I continue to recommend use of a historic filing frequency to determine a normalization period for UGI Gas.

Q. DO YOU AGREE WITH MS. HAZENSTAB THAT BOTH COLUMBIA GAS 2020 AND PECO GAS 2021 ARE DISTINGUISHIBLE FROM THE INSTANT CASE?

A. No. However, because this is a legal argument, it will be further addressed in the I&E briefs by the I&E prosecutor.

[7] Petition of UGI Utilities, Inc. – Gas Division for Approval of its Second Long Term Infrastructure Improvement Plan, Docket No. P-2019-3012337 (Opinion and Order entered Dec. 19, 2019).

Q. DO YOU AGREE WITH MS. HAZENSTAB THAT THE ONE-YEAR STAY-OUT CLAUSE FROM THE PRIOR PROCEEDING SHOULD BE FACTORED INTO THE CALCULATION OF FILING FREQUENCY?

A. No. While it may be true that UGI Gas was subject to a one-year stay-out clause in its prior proceeding[8], this one-year period should not be excluded when calculating UGI Gas's historic filing frequency of base rate cases. By agreeing to the one-year stay-out clause, UGI Gas made an affirmative decision not to file a rate case. It is appropriate to include the one-year period as part of the historic filing frequency because UGI Gas was in control of the timeframe for when it could file.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I continue to recommend an allowance of $633,000, or a reduction of $422,000 ($1,055,000 - $633,000) to the Company's annual rate case expense claim.

UNRECOVERED ENVIRONMENTAL REMEDIATION EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATIONS IN DIRECT TESTIMONY FOR UNRECOVERED ENVIRONMENTAL REMEDIATION EXPENSE.

A. In my direct testimony, I made two recommendations concerning unrecovered

[8] *PA PUC v. UGI Utilities, Inc – Gas Division* Docket No. R-2019-3015162, Order Entered October 8, 2020; Paragraph 9.

environmental remediation expense. First, I recommended that the Company be required to provide a full line-by-line account of the yearly amortizations of unrecovered environmental remediation expense in the next base rate case. Additionally, I recommended that unrecovered 2020 and 2021 environmental remediation expense be amortized over a five-year period resulting in an allowance of $465,400 or a reduction of $1,861,600 ($2,327,000 - $465,400) to the Company's claim. The five-year amortization period is based on the amortization period from the prior Opinion and Order as opposed to the Company's proposed one-year amortization period to align with the rate case amortization period.[9]

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATIONS?

A. Yes. UGI Gas witness Vivian K. Ressler[10] responded to my recommendations.

Q. SUMMARIZE MS. RESSLER'S RESPONSE TO YOUR RECOMMENDATION THAT THE COMPANY BE REQUIRED TO PROVIDE A LINE-BY-LINE ACCOUNT OF YEARLY AMORTIZATIONS IN ITS NEXT RATE CASE.

A. Ms. Ressler agrees with my recommendation that the Company be required to

9 I&E Statement No. 3, pp. 9-11.
10 UGI Gas Statement No. 3-R, p. 7.

provide a full line-by-line account of yearly amortizations of unrecovered environmental remediation expenses in its next base rate proceeding.[11] Additionally, Ms. Ressler prepared UGI Gas Exhibit VKR-2R to help explain how the Company has amortized under-recovered environmental remediation expense and agreed to provide a similar schedule in the next rate case filing.

Q. SUMMARIZE MS. RESSLER'S RESPONSE CONCERNING THE UNRECOVERED 2020/2021 ENVIRONMENTAL REMEDIATION EXPENSE AMORTIZATION PERIOD.

A. Ms. Ressler disagrees with my proposed five-year amortization period for unrecovered 2020/2021 environmental remediation costs. The Company selected a one-year amortization period because it anticipates that another rate case would be filed within the next year. Ms. Ressler asserts that a five-year recovery period represents a mismatch between the period in which costs are incurred and when they would be allowed to be recovered and would unfairly frustrate the Company's ability to timely recover the full amount of these expenses. Ms. Ressler further states that my recommendation based on prior case settlement should have no persuasive value in this proceeding. Ms. Ressler also opines that the Company has spent more than it has recovered in rates for each year since 2019, thereby adding to its regulatory asset under-recovery each year.[12]

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[11] UGI Gas Statement No. 3-R, pp. 8-9.
[12] UGI Gas Statement No. 3-R, pp. 9-13.

Q. WHAT IS YOUR RESPONSE TO MS. RESSLER?

A. Upon consideration of points made in her rebuttal testimony, I accept that the amortization period for the unrecovered 2020/2021 expense should be tied to the rate case normalization period, however as discussed above, I disagree with the Company's one-year rate case normalization period. I find persuasive Ms. Ressler's statement that a five-year amortization period for unrecovered 2020 and 2021 environmental remediation expenses would unfairly delay recovery of the full amount of these expenses. The Company has incurred expenditures for environmental remediation for each year since 2019, resulting in increases to its regulatory asset each year. Furthermore, I agree with the company that the three-year average of environmental expenditures of $5.171 million should be used as the budgeted amount in the FPFTY, and that differences between $5.171 million and actual expenditures should be deferred as a regulatory asset (where expenditures are greater than $5.171 million per year) or as a regulatory liability (where expenditures are less than $5.171 million per year).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. I have adjusted my recommended amortization period to align with my recommended rate case expense normalization period of 20 months. This adjustment results in an annual allowance of $1,396,200 [($2,327,000 ÷ 20 months) x 12 months] or a reduction of $930,800 ($2,327,000 - $1,396,200) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR UPDATED RECOMMENDATION?

A. Upon reviewing the Company's rebuttal testimony, I accept that it would make more sense to fully amortize this expense before the next base rate filing and have updated my recommendation accordingly.

<u>OSHA/EMERGENCY TEMPORARY STANDARD (ETS) COMPLIANCE COSTS</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR OSHA/ETS COMPLIANCE COSTS.

A. First, I recommended that $1,830,066 be disallowed for OSHA/ETS compliance costs because the Company withdrew a majority of its claim after the U.S. Supreme Court overturned the Federal Mandate. Next, I recommended that the remaining OSHA/ETS compliance costs of $52,934 be amortized over a 20-month period resulting in an annual allowance of $31,760 [($52,934 ÷ 20 months) x 12].[13]

Q. DID ANY COMPANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. UGI Gas witness Vivian K. Ressler[14] responded to my recommendation.

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13 I&E Statement No. 3, pp. 14-15.

14 UGI Gas Statement No. 3-R, pp. 42-43.

Q. SUMMARIZE MS. RESSLER'S RESPONSE IN REBUTTAL TESTIMONY.

A. Ms. Ressler accepts the disallowance of $1,830,066 due to the Company's withdrawal of a majority of its claim and recommends a one-year amortization period based on UGI Gas witness Ms. Hazenstab's recommended one-year rate case expense normalization period.[15]

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I continue to recommend an allowance of $31,760, or a reduction of $21,174 ($52,934 - $31,760) to the Company's OSHA/ETS compliance costs in line with my recommended rate case expense normalization period.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

[15] UGI Gas Statement No. 3-R pp. 42-43.

I&E Statement No. 4
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Direct Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Test Year
Present Rate Revenue
Weather Normalization Adjustment
Average Bill Comparison
Scale Back of Rates

TABLE OF CONTENTS

INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ethan H. Cline. My business address is 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation and Enforcement (I&E) as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in the proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to evaluate UGI Utilities, Inc. - Gas Division's ("UGI" or "Company") request for an annual increase in operating revenue of approximately $82.7 million. My testimony will address issues related to the weather normalization adjustment, present rate revenue, and scale back of rates.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 4 contains schedules relating to my testimony.

WEATHER NORMALIZATION ADJUSTMENT

Q. WHAT IS A WEATHER NORMALIZATION ADJUSTMENT MECHANISM?

A. As stated on page 6 of UGI Statement No. 11, a Weather Normalization Adjustment ("WNA") mechanism adjusts a customer's bill to correct for variations from normal weather in order to have the bill reflect normal weather conditions through credits and surcharges for colder than normal and warmer than normal weather, respectively.

Q. IS UGI PROPOSING TO INTRODUCE A WEATHER NORMALIZATION ADJUSTMENT IN THIS CASE?

A. Yes. UGI is proposing to implement a WNA mechanism that adjusts billings on a monthly basis as the bill is being calculated and issued (UGI St. No. 11, p. 7).

Q. IS UGI'S PROPOSED WNA MECHANISM SIMILAR TO A WNA RIDER OF ANOTHER PENNSYLVANIA NATURAL GAS DISTRIBUTION COMPANY?

A. Yes. UGI claims that its proposed WNA mechanism is similar to the calculation of Columbia Gas of Pennsylvania's ("Columbia") WNA rider (UGI St. No. 11, p. 9).

Q. DO YOU AGREE THAT THE UGI WNA IS SIMILAR TO THE COLUMBIA WNA APPROVED BY THE COMMISSION?

A. No. Columbia's WNA includes a deadband range while the UGI's proposal does not. The Company believes that application of a deadband adds unnecessary complexity to the rider. Additionally, UGI stated that the WNA's intended goal is to stabilize billings and distribution revenues from readily identified weather related variances rather than "arbitrarily established" elements of weather variance (UGI St. No. 11, p. 11).

Q. WHAT IS A DEADBAND?

A. A deadband is a threshold of Normal Heating Degree Days where the WNA adjustment is not triggered (UGI St. No. 11, p. 11).

Q. DO ANY OTHER PENNSYLVANIA NGDCS WITH A WNA UTILIZE A DEADBAND?

A. Yes. As previously mentioned, Columbia Gas has a 3% deadband and PGW has a 1% deadband (UGI St. No. 11, p. 11).

Q. ARE THERE CURRENTLY ANY PENNSYLVANIA NGDCS WITH A WNA THAT DO NOT UTILIZE A DEADBAND?

A. I am not aware of any Pennsylvania NGDC with a WNA that does not utilize a deadband.

Q. HAS THE COMMISSION DESCRIBED WHY A DEADBAND COMPONENT IS APPROPRIATE IN A WNA?

A. Yes. In Columbia's 2020 base rate case, the Commission determined that "without an extraordinary set of circumstances, there is no need for Columbia to reconcile day-to-day temperature variations that are part of normal business." (Docket No. R-2020-3018835, Order entered February 19, 2021, pp. 264-265).

Q. WHY IS A DEADBAND A REASONABLE PROVISION TO INCLUDE IN UGI'S PROPOSED WNA?

A A WNA is a departure from traditional ratemaking in that it allows the Company to adjust a customer's base rate bill, which was calculated based on Commission approved rates, outside the scope of a base rate case. I believe such a departure from traditional ratemaking should only occur due to circumstances that are an extraordinary departure from normal operating conditions, such as abnormal weather. There is no need to reconcile the day-to-day temperature variations that can be considered a normal part of doing business. Therefore, a 3% deadband as is applicable in Columbia Gas' WNA mechanism is a reasonable provision because it allows for a range of what is considered "normal" weather in which the Company's Commission-approved rates would be applied without adjustment. Without the deadband customer rates could be subject to constant adjustment for normal weather variations in every billing cycle.

Q. DID UGI PROVIDE ANY EVIDENCE THAT WOULD SHOW WHY A DEADBAND WOULD NOT BE APPROPRIATE IN ITS CIRCUMSTANCES?

A. No. UGI presented no evidence to show that, unlike other Pennsylvania NGDCs, UGI should be permitted to reconcile day-to-day temperature variations that are part of normal business. UGI provided no evidence or support that would show how or why a departure from the Commission's previous ruling in Columbia regarding the deadband should not be followed.

Q. WHAT DO YOU RECOMMEND REGARDING UGI'S PROPOSED WNA?

A. I recommend that UGI's WNA be approved on the condition that a 3% deadband is included. My recommendation maintains consistency with the Commission's previous ruling and with Columbia's existing WNA.

TEST YEAR

Q. WHAT IS A TEST YEAR AND HOW IS IT USED?

A. A test year is the twelve-month period over which a utility's costs and revenues are measured as the basis for setting prospective base rates. In order to meet its burden of proof, a utility has the option of selecting to use a historic test year (HTY), a future test year (FTY), or a fully projected future test year (FPFTY). An HTY is a twelve-month period selected by a company that represents the most recent full year of actual data. The FTY begins the day after the HTY ends and is determined using a combination of actual data and a projection of annualized and normalized estimates of future revenues and expenses and a corresponding measure of value at the end of that period. The FPFTY is defined as the twelve-month period that begins with the first month that the new rates will be placed into effect, after the application of the full suspension period permitted under Section 1308(d). The FPFTY is made up entirely of projections forecasted by the Company.

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. UGI has selected the year ended September 30, 2021 as the HTY, the year ending September 30, 2022 as the FTY, and the year ending September 30, 2023 as the FPFTY (UGI St. No. 2, p. 2).

Q. WHAT TEST YEAR HAS THE COMPANY BASED ITS REVENUE REQUIREMENT UPON IN THIS PROCEEDING?

A. UGI based its requested revenue requirement on the FPFTY ending September 30, 2023 (UGI St. No. 1, p. 6).

<u>PRESENT RATE REVENUE</u>

Q. WHAT AMOUNT PRESENT RATE REVENUE IS THE COMPANY REFLECTING FOR THE FPFTY ENDING SEPTEMBER 30, 2023?

A. UGI is reflecting approximately $1,062,724,000 of present rate revenue including gas costs, surcharges, and other operating revenues (UGI Book V, FPFTY Ex. A-1 p. 1).

Q. DO YOU AGREE WITH THE CLAIMED $1,062,724,000 OF PRESENT RATE REVENUE FOR THE FPFTY?

A. No. As described below, I have determined that UGI has understated its present rate revenue in the FPFTY and I am recommending an increase of $14,648,202 from $662,172,239 to $676,822,441. My recommendation is based on two adjustments to UGI's claimed $662,172,239 of present rate revenue in the FPFTY as discussed below.

Q. WHAT IS THE BASIS OF YOUR TWO ADJUSTMENTS TO UGI'S PRESENT RATE REVENUE CLAIM IN THE FPFTY?

A. First, I will address the rate class R/RT heating customer usage decline reflected in the FPFTY that was projected beyond the end of the FPFTY. Second, I will address the overall regression analysis performed by UGI to project usage per R/RT heating customer to determine sales volumes.

<u>R/RT HEATING CUSTOMER USAGE DECLINE</u>

Q. WHAT IS THE COMPANY'S CLAIM REGARDING R/RT HEATING CUSTOMER USAGE?

A. UGI projected that R/RT heating customer usage is declining and its usage per customer projections included a reduction to account for conservation items and measures including, but not limited to, regular and accelerated appliance replacements, high efficiency appliance installations, setback thermostat installations, modifications to new and existing buildings that are designed to decrease energy consumption, and changes in consumer behavior in response to energy price changes, and other economic influences (UGI St. No. 8, p. 10).

Q. WHAT AVERAGE USAGE PER R/RT HEATING CUSTOMER IS THE COMPANY PROJECTING?

A. The Company's projected annual usage in the FPFTY for R/RT heating customers is approximately 87.8 Mcf per customer (UGI, Book II, Attachment SDR-RR-11(a), p. 8 of 9).

Q. HOW DID UGI PROJECT THAT R/RT HEATING CUSTOMERS WOULD USE 87.8 MCF PER YEAR?

A. The Company performed a regression analysis of actual usage, degree day, lagged heating degree days, and the weighted trend data for the period October 2003 through September 2021 (UGI Book II, Attachment SDR-RR-11(a)). The Company then used the results of the regression analysis to project the usage decline per month through the FTY, the FPFTY, and through March 2024, which is six months past the end of the FPFTY with the final result being the projected 87.8 Mcf per customer. UGI also projected its commercial usage through March 2024, but that projection did not result in any change from the year end September 2023 projection as shown on UGI Exhibit SAE 3(b). Therefore, my discussion will focus on R/RT Heating customers.

Q. DO YOU AGREE WITH THE COMPANY'S PROJECTED USAGE PER R/RT HEATING CUSTOMER?

A. No. I believe the Company has understated its projected usage per customer for R/RT heating customers.

Q. WHY HAVE YOU CONCLUDED THE COMPANY'S PROJECTED USAGE PER CUSTOMER FOR R/RT HEATING CUSTOMERS IS UNDERSTATED?

A. My disagreement with the Company's determination of average usage per customer concerns the inclusion of usage decline beyond the end of the FPFTY period used to project the average usage per R/RT heating customer in the FPFTY. The FPFTY ends September 30, 2023; however, the Company's analysis projects residential heating customer usage declines through March 2024, which is six months beyond the FPFTY.

Q. DID THE COMPANY EXPLAIN WHY IT EXTENDED THE DECLINE IN USAGE BEYOND THE END OF THE FPFTY?

A. In its response to I&E-RS-14-D, attached as I&E Ex. No. 4, Sch. 1, the Company stated that it used a "mid-period convention in order to capture the full annualized impacts related to customer conservation activities" through the September 30, 2023 end date of the FPFTY.

Q. IS THE USE OF A MID-YEAR CONVENTION APPROPRIATE?

A. No. The Company has selectively used a mid-year convention to make a projection that extends beyond the end of the FPFTY for usage decline when all other financial criteria are based on the end of the FPFTY. This inappropriately misaligns data for determination of a revenue requirement and affords the Company a greater revenue increase than is appropriate for its FPFTY claim. I explain the impact of this discrepancy further below.

Q. IS THERE ANY BASIS FOR PROJECTING USAGE BEYOND THE END OF THE FPFTY?

A. No. The Company selected September 30, 2023 as the end of the FPFTY, and there is no basis for projecting usage six months beyond the end of the FPFTY. The test year period is meant to be a snapshot look at one year of a utility's revenue requirement such that all inputs into the ratemaking equation, i.e. rate base, depreciation, revenues, expenses, taxes, are determined using the same time period. Therefore, the average usage per R/RT heating customer that is used to determine revenue should also be determined consistent with the end-of-FPFTY time period. For example, the Company based its projection of customer count as of the end of the FPFTY; therefore, it is improper to base the usage per R/RT heating customer on the projected average usage per customer six months past the end of the FPFTY as a different customer count would be applicable to that time period. The proposed mismatch in the usage per customer conflicts with all other ratemaking inputs.

Q. WILL THE USE OF "ANNUALIZED" USE PER CUSTOMER DATA BENEFIT THE COMPANY THROUGH INCREASED REVENUES?

A. Yes. If permitted to use the mid-period annualization, the Company would receive additional revenue during the FPFTY. This additional revenue would be the result of deducting the usage of R/RT heating customers that are projected to use less gas after the end of the FPFTY before these customers use less gas. For example, the Company may believe that if a R/RT heating customer replaces their furnace with a high efficiency furnace in February or March 2024, then that customer's usage should be "annualized" for the FPFTY ending September 2023. However, in this example, this R/RT heating customer will use the higher level of gas from October 1, 2023 through January or February 2024, which is 4-5 months <u>beyond</u> the end of the FPFTY. As a result, the Company will sell more gas to this customer for the prior 16-17 months and keep the incremental revenue until that customer potentially uses less gas in February or March of 2024.

Q. WILL THE CUSTOMER AND THE COMPANY EXPERIENCE LOWER SALES FROM A CUSTOMER THAT INSTALLS A HIGH EFFICIENCY HEATING SYSTEM IN FEBRUARY OR MARCH IMMEDIATELY?

A. No. Any furnace replacement in February or March occurs towards the end of the heating season. As such, the savings experienced by those R/RT heating customers would be much less than residential customers that replaced their heating system at the beginning heating season in September or October. Since customers use much less gas in the summer, the late winter/early spring furnace replacement described above lessens the impact on usage until the following heating season. Therefore, that customer (and the Company) likely would not experience any potential meaningful usage decline until the winter heating season begins in the following October. For those customers replacing their heating systems in February or March of 2023, their saving would not be experienced fully until a full year after the end of the of the FPFTY in this case.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS CONCERNING THE COMPANY'S "ANNUALIZATION" OF POST FPFTY USAGE DECLINES?

A. The usage decline beyond the end of the FPFTY should be rejected. There is no justification for allowing the level of usage projected at the end of the FPFTY to be "annualized" by projecting out to March 2024. The inclusion of such an "annualization" will benefit the Company to the detriment of customers.

Q. WHAT AVERAGE USAGE PER R/RT CUSTOMER DO YOU RECOMMEND TO ELIMINATE THE INCLUSION OF ANY POST FPFTY DECLINE?

A. I recommend that the average usage per R/RT customer be increased by 0.1307 Mcf per customer per year (I&E Ex. No. 4, Sch. 2, line 6). This 0.1307 Mcf per customer per year was determined by subtracting the 87.9625Mcf per customer at the end of the FPFTY from the 87.8318 Mcf per customer as of March 2024 as shown on UGI Book II, Attachment SDR-RR-11(a), page 9.

Q. HOW MUCH DO GAS VOLUMES INCREASE IF THE AVERAGE USAGE PER R/RT CUSTOMER IS INCREASED BY 0.1307 PER CUSTOMER PER YEAR?

A. Gas volumes increase by 77,061 Mcf (589,601 X 0.1307). This 77,061 Mcf of gas was determined by multiplying the 0.1307 per customer per year times 589,601 R/RT heating customers shown on UGI Book III, Exhibit SAE-7(a).

Q. HOW MUCH DOES PRESENT RATE USAGE REVENUE INCREASE IF THE AVERAGE USAGE PER R/RT HEATING CUSTOMER IS INCREASED BY 0.1307 MCF PER CUSTOMER PER YEAR?

A. If my recommendation to use the FPFTY year-end usage is approved, present rate usage revenue increases by $316,752 (I&E Ex. No. 4, Sch. 2, line 6, col. D). This $316,752 of present rate R/RT revenue was determined by multiplying the 77,061 Mcf of gas described above times the present usage rate of $4.1104 per Mcf shown on UGI Book V, Exhibit E, p. 2. The result would be to increase the Company's claimed present rate revenue for residential heating customers by $316,752 from $662,174,239 to $662,490,991.

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE REVENUE BY $316,752 TO $662,490,991 SHOULD THERE BE A CORRESPONDING INCREASE IN PURCHASED GAS REVENUE AND EXPENSES?

A. Yes. Under present rates, the PGC volumes equal approximately 85.47% of total usage volumes (I&E Ex. No. 4, Sch. 2, line 11, col. A). Therefore, increasing total R/RT sales volumes by 77,061 Mcf increases the PGC by 65,862 Mcf (77,061 Mcf X 0.8547) (I&E Ex. No. 4, Sch. 2, line 10, col. B). This results in an increase in PGC revenue and expenses of $413,399 (65,862 Mcf X the $6.2767 per Mcf PGC rate) (I&E Ex. No. 4, Sch. 4, line 10, col. D).

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE REVENUE BY $541,133 TO $191,863,159 SHOULD THERE BE A CORRESPONDING INCREASE IN OTHER SURCHARGES?

A. Yes. Since the following surcharges are based upon volumes or revenue, they would each increase if the Commission accepts my recommendation to eliminate the post FPFTY usage decline. Under present rates, the Merchant Function Charge will increase by $8,971 to $6,189,251 (I&E Ex. No. 4, Sch. 2, line 14, col. D). The Gas Procurement Charge will increase by $4,347 to $2,999,100 (I&E Ex. No. 4, Sch. 2, line 17, col. D). The Universal Service Program rider will increase by $25,484 to $17,562,382 (I&E Ex. No. 4, Sch. 2, line 20, col. D). The Energy and Conservation Efficiency Rider will increase by $16,006 to $11,042,760 (I&E Ex. No. 4, Sch. 2, line 23, col. D).

Q. WHAT IS THE TOTAL INCREASE IN PRESENT RATE REVENUE IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE DISTRIBUTION VOLUME BY 77,061 MCF?

A. Present rate revenue increases by $427,964 from $662,174,239 to $662,602,203 (I&E

Ex. No. 4, Sch. 2, line 29, col. D). It should be noted that, if the Commission accepts my second adjustment, discussed below, then this $427,964 adjustment would not be added as it is already a part of the regression analysis adjustment below.

R/RT HEATING CUSTOMERS – REGRESSION ANALYSIS

Q. WHAT IS THE SECOND ADJUSTMENT YOU RECOMMEND TO THE COMPANY'S PROJECTED USAGE FOR R/RT HEATING CUSTOMERS?

A. As described above, my second recommendation addresses UGI's use of 18 years of data to project the 87.8 Mcf annual usage for the R/RT heating customers (UGI Book III, Ex. SAE-7(a)).

Q. DID THE COMPANY ADDRESS WHY IT SELECTED 18 YEARS?

A. No. UGI only stated that it selected 18 years of data because October 2003 was the earliest common data set available for the entire service territory (UGI St. No. 8, p, 10).

Q. DO YOU AGREE THAT USING ALL AVAILABLE DATA TO PERFORM THE REGRESSION ANALYSIS TO DETERMINE USAGE DECLINE IS REASONABLE?

A. No. As a rule, older usage data is less indicative of recent trends. As Ms. Epler described on page 10 of UGI Statement No. 8, the changes in usage per customer are influenced by regular appliance replacements, accelerated appliance replacements, high-efficiency appliance installations, setback thermostat installations, modifications to new and existing buildings that are designed to decrease energy consumption, and changes in consumer usage behavior due to other economic influences. It is reasonable to assume that, as UGI's service territory becomes more saturated with high-efficiency appliance installations and more buildings are modified as time goes on, the decline in residential usage per customer will have a progressively declining impact. Therefore, it is not reasonable to allow less significant older data from a time period when the service territory was not as saturated with usage reducing appliances to influence the results of the projection of future usage.

Q. WHAT TIME PERIOD DO YOU RECOMMEND FOR THE REGRESSION ANALYSIS IN THIS CASE?

A. In this case, I recommend the 15-year time period from October 2006 through September 2021 for the residential usage per customer regression analysis.

Q. WHY DO YOU RECOMMEND THE USE OF 15 YEARS TO PROJECT THE AVERAGE USAGE PER R/RT CUSTOMER FOR THE FPFTY?

A. I recommend the use of 15-years of data for several reasons. First, a fifteen-year time period is consistent with the reasons UGI described for utilizing a multi-year regression period. Second, the 15-year time period is consistent with the time period used for the Company's weather normalization adjustment. Third, the Company has supported the use of 15-year time period for its regression analysis in its previous cases. Finally, I believe that usage and temperature data older than 15 years is not representative of recent usage trends on which to base the usage projection.

Q. WHAT REASONS DID UGI PROVIDE FOR UTILIZING A MULTI-YEAR REGRESSION ANALYSIS TO DETERMINE RESIDENTIAL USE PER CUSTOMER TRENDS?

A. On page 11 of UGI Statement No. 8, Ms. Epler stated that "[t]he Company decided to use the multi-year period because it provides a larger sample set of data to smooth out short-term variations and capture the underlying long-term use per customer trends to more accurately project usage per customer during the period rates are likely to be in effect."

Q. IS THE USE OF A FIFTEEN-YEAR PERIOD IN THE MULTI-YEAR REGRESSION ANALYSIS CONSISTENT WITH THE COMPANY'S REASONS FOR USING A MULTI-YEAR REGRESSION ANALYSIS?

A. Yes. A fifteen-year period remains long enough to smooth out short-term variations and capture the underlying long-term use per customer trends while having the added benefit of not including data that is no longer representative of more recent trends, such as data before October 2006.

Q. WHAT TIME PERIOD DOES THE COMPANY USE TO DETERMINE ADJUSTMENTS FOR TEMPERATURE DATA?

A. UGI has consistently used, over the previous seven base rate cases of both UGI and its former affiliates, a 15-year period updated every five years to determine normal heating degree days (UGI St. No. 8, p. 7). While the analyses performed to determine normalized temperatures and use per customer are different types of analyses, the fact that the Company has consistently used 15-years to normalize highly variable weather data shows that the use of 15-years of data to project use per customer data is reasonable.

Q. HAS UGI SUPPORTED THE USE OF 15 YEARS OF DATA TO PERFORM ITS USE PER CUSTOMER ANALYSIS IN PREVIOUS CASES?

A. Yes. The UGI gas rate case at Docket R-2018-3006814 ("2018 Base Rate case") the Company utilized and supported using 15 years of data to project usage per customer that is used to determine sales volumes for R/RT heating customers at the end of the FPFTY.

Q. IN THE 2018 BASE RATE CASE, DID THE COMPANY STATE THAT 15 YEARS OF DATA WAS STATISTICALLY VALID TO PROJECT R/RT HEATING CUSTOMERS USAGE?

A. Yes. In the 2018 base rate case, the Company supported the use of 15 years of data stating:

> "This is the same methodology was used by the Company in the past several rate base rate cases. UGI's use of a fifteen-year period in its regression analysis is statistically valid and consistent with its use of extended, available periods of data to show long term trends in use per customer" (UGI St. No. 8-R, p. 7).
>
> "UGI Gas's 15-year regression results are strongly supported by other data from the American Gas Association ("AGA") and the US Energy Information Administration ("EIA")" (UGI St. No. 8-R, p. 9).

Q. DOES USING 15 YEARS OF DATA RATHER THAN 18 YEARS OF DATA MAKE A DIFFERENCE IN THE USAGE PER R/RT HEATING CUSTOMER?

A. Yes. Using 15 years of data, the projected average usage per R/RT customer for the FPFTY ending September 30, 2023 is approximately 90.2576 Mcf per year (I&E Ex. No. 4, Sch. 3, p. 4). This shows that when the stale data beyond the fifteen-year time period is removed, the average usage per R/RT customer increases from 87.8138 Mcf per customer per year to 90.2576 Mcf per customer per year, which is an increase of 2.4438 (90.2576 – 87.8138) Mcf per R/RT customer per year.

Q. HOW MUCH DO GAS VOLUMES INCREASE IF THE AVERAGE USAGE PER R/RT CUSTOMER IS INCREASED BY 2.4438 MCF PER CUSTOMER PER YEAR?

A. Gas volumes increase by 1,440,867 Mcf (589,601 X 2.4438). This 1,440,867Mcf of gas was determined by multiplying the 2.4438 MCF per customer per year times 589,601 R/RT heating customers shown on UGI Book III, Exhibit SAE-7(a).

Q. HOW MUCH DOES PRESENT RATE USAGE REVENUE INCREASE IF THE AVERAGE USAGE PER R/RT HEATING CUSTOMER IS INCREASED BY 2.4438 MCF PER CUSTOMER PER YEAR?

A. If my recommendation to use the FPFTY average usage is approved, present rate usage revenue increases by $5,922,539 (I&E Ex. No. 4, Sch. 4, line 6). This $5,922,539 of present rate R/RT revenue was determined by multiplying the

1,440,867 Mcf of gas described above times the present usage rate of $4.1104 per Mcf shown on UGI Book V, Exhibit E, p. 2. The result would be to increase the Company's claimed present rate revenue for residential customers by $5,922,539 from $662,174,239 to $668,096,778.

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE REVENUE BY $5,922,539 TO $668,096,778 SHOULD THERE BE A CORRESPONDING INCREASE IN PURCHASED GAS REVENUE AND EXPENSES?

A. Yes. Under present rates, the PGC volumes equal approximately 85.47% of total usage volumes (I&E Ex. No. 4, Sch. 4, line, col. A). Therefore, increasing total R/RT sales volumes by 1,440,867 Mcf increases the PGC by 1,231,480 Mcf (1,440,867 Mcf X 0.8547) (I&E Ex. No. 4, Sch. 4, line 10 col. B). This results in an increase in PGC revenue and expenses of $7,729,631 (1,231,480 Mcf X the $6.2767 per Mcf PGC rate) (I&E Ex. No. 4, Sch. 4, line 10, col. D).

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE REVENUE BY $5,922,539 TO $668,096,778 SHOULD THERE BE A CORRESPONDING INCREASE IN OTHER SURCHARGES?

A. Yes. Since the following surcharges are based upon volumes or revenue, they would each increase if the Commission accepts my recommendation to eliminate the post FPFTY usage decline. Under present rates, the Merchant Function Charge will increase by $167,733 to $6,348,013 (I&E Ex. No. 4, Sch. 4, line 14, col. 14). The Gas Procurement Charge will increase by $81,278 to $3,076,030 (I&E Ex. No. 4, Sch. Post-FPFTY, line 17, col. D). The Universal Service Program rider will increase by $118,297 to $17,655,195 (I&E Ex. No. 4, Sch. 4, line 20, col. D). The Energy and Conservation Efficiency Rider will increase by $299,268 to $11,101,118 (I&E Ex. No. 4, Sch. 4, line 23, col. D).

Q. WHAT IS THE TOTAL INCREASE IN PRESENT RATE REVENUE IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE DISTRIBUTION VOLUME BY 1,440,867 MCF?

A. Present rate revenue increases by $14,648,202 from $662,174,239 to $676,822,441 (I&E Ex. No. 4, Sch. 4, line 29, col. D).

Q. DOES YOUR RECOMMENDATION TO INCREASE USAGE PER R/RT HEATING CUSTOMER INCLUDE THE VOLUMES AND DOLLARS OF YOUR FIRST RECOMMENDATION CONCERNING POST FPFTY R/RT HEATING USAGES?

A. Yes. As I stated above, the adjustments in my second recommendation are inclusive of the adjustment I described regarding the inclusion of post FPFTY usage data. Therefore, if the Commission accepts my second recommendation and adjustments, there is no need to reflect the first adjustment of $316,752 of present rate revenue nor the $413,399 of additional purchase gas expense shown on I&E Ex. No. 4, Sch. 2, line 29 concerning post FPFTY usage declines.

<u>MISCELLANEOUS REVENUE</u>

Q. WHAT IS THE COMPANY'S CLAIM FOR MISCELLANEOUS REVENUE UNDER PRESENT RATES IN THE FPFTY?

A. The Company's claim for miscellaneous revenue under present rates in the FPFTY is $1,998,000 (UGI Book IX, Schedule E, p. 4).

Q. DID THE COMPANY PROVIDE AN UPDATE TO THIS CLAIM DURING THE PROCESS OF DISCOVERY?

A. Yes. In its response to I&E-RS-27, attached as I&E Exhibit No. 4, Schedule 5, the Company admitted that it inadvertently included the company share of off-system sales that should be reflected below the line for ratemaking purposes. The Company further indicated that it would reduce its miscellaneous revenue claim by $1,003,000 from $1,998,000 to $995,000 to correct this error.

Q. IS THE COMPANY'S PLANNED ADJUSTMENT TO ITS MISCELLANEOUS REVENUE CLAIM REASONABLE?

A. Yes. It is reasonable for the Company to correct its claim for miscellaneous revenues in its rebuttal testimony.

<u>AVERAGE BILL COMPARISON</u>

Q. DID THE COMPANY MAKE ANY CLAIMS IN ITS DIRECT TESTIMONY REGARDING THE COMPARISON OF CURRENT RESIDENTIAL RATES TO HISTORIC RESIDENTIAL RATES?

A. Yes. On page 7 of UGI Statement No. 1, the Company claimed that "the Company's average customer bills are less than they were in 2008."

Q. DID THE COMPANY PROVIDE ANY DATA TO SUPPORT ITS CLAIM THAT THE COMPANY'S AVERAGE CUSTOMER BILLS ARE LESS THAN THEY WERE IN 2008?

A. No. The Company provided no data, support, or any other form of analysis support its claim regarding its average customer bills in 2008.

Q. IS THE COMPANY'S CLAIMED COMPARISON OF RATES IN 2008 REPRESENTATIVE OF RATE INCREASES CUSTOMERS HAVE EXPERIENCED IN RECENT HISTORY?

A. No. The level of customer rates in 2008 is not representative of base rate increases customers have experienced in recent history. Specifically, UGI customers, and the customers of its former affiliates, have experienced rate increases in 2016 (UGI Utilities, Inc., Docket No. R-2015-2518438), 2017 (UGI Penn Natural Gas, Inc., Docket No. R-2016-2580030), 2019 (UGI Utilities, Inc., Docket No. R-2018-3006814), 2019 (UGI Utilities, Inc., Docket No. R-2019-3015162), and now in 2022 with the current proceeding.

Q. ARE YOU AWARE OF ANY RATE DECREASES PROPOSED BY UGI OR ITS FORMER AFFILIATES SINCE 2008?

A. No. I am not aware of any rate decreases proposed by UGI or its former affiliates since 2008.

Q. IF UGI HAS ONLY INCREASED ITS BASE RATES SINCE 2008, HOW COULD CUSTOMER RATES BE LOWER NOW THAN IN 2008?

A. Because UGI has not provided any data supporting its claim that rates are lower now than in 2008 despite the multiple increases in base rates in that same time period, it is not possible to accurately determine the cause of this anomaly. One explanation could be that UGI is including the Gas Cost Rate in its analysis.

Q. HOW HAS THE GAS COST RATE CHANGED BETWEEN 2008 AND NOW?

A. In 2008, the purchased gas rate (PGC) for UGI Utilities peaked at approximately $13.261 per Mcf. In this filing, the Company reflected a PGC rate of $6.2757 per Mcf (I&E Ex. No. 4, Sch 6, pp. 1-2). Therefore, even after more than doubling the customer charge, increasing the distribution rate, and creating numerous surcharges, the total bill of a customer is less than it was in 2008 because the PGC component of a customer's bill was so large.

Q. WILL THIS ALWAYS BE THE CASE?

A. Not necessarily. The PGC rate fluctuates and could increase in the future. Just recently the PGC rate increased from $4.4594 per MCF in June 2021 to $6.2767 today (I&E Ex.

No. 4, Sch. 7, pp. 1-2). This is an increase of $1.8173 per Mcf or 40.8%. Given this recent increase, it is certainly possible future increases could match or be greater than the 40.8%.

Q. SHOULD THE GAS COST RATE BE INCLUDED IN A COMPARISON OF HISTORIC TO CURRENT RATES IN THE CONTEXT OF A BASE RATE CASE?

A. No. Gas Cost Rates do not change as a result of a base rate case. In fact, UGI has no control over the historic or present level of the Gas Cost Rate. Therefore, it is disingenuous for UGI to claim credit for lower overall rates when the driving factor of that circumstance is entirely outside of UGI's control.

Q. WHAT DO YOU RECOMMEND REGARDING UGI'S CLAIM THAT CURRENT RATES ARE LOWER THAN RATES IN 2008?

A. I recommend that this claim be disregarded because it is unsupported and misleading for the reasons I described above.

Q. DID UGI INCLUDE ANY OTHER INACCURATE CLAIMS IN ITS FILING?

A. Yes. On page 10 of UGI Statement No. 1, Mr. Brown included a chart showing a comparison of UGI's current and proposed rates of residential heating customers of the major Pennsylvania NGDCs.

Q. DID THE COMPANY EXCLUDE A MAJOR PENNSYLVANIA GAS COMPANY IN ITS RESIDENTIAL BILL COMPARISON?

A. Yes. The Company failed to include National Fuel Gas Distribution Corporation ("NFGD"). If they had, the Company would have determined that the average bill of an NFGD customer is much lower than the average bill of a UGI customer. After the UGI rate increases, the average bill of a residential customer will be $108 per month. With this increase and including NFGD in the comparison results show that four major gas distribution companies will have lower average rates than UGI instead of just three.

Q. WHAT DO YOU RECOMMEND THE COMPANY DO IN FUTURE FILINGS?

A. I recommend that if the Company chooses to provide a comparison of its rates to other NGDCs in Pennsylvania, then the Company should include all major gas companies and compare proposed rates after the UGI increase.

<u>SCALE BACK OF RATES</u>

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED INCREASE BY CLASS?

A. The Company proposed R/RT revenue increase by $68,115,150, N/NT revenue - increase by $14,452,827, DS revenue by, $653,949, LFD revenue by $1,531,227, XD revenue decrease by $931,834 and Interruptible revenue decrease by $1,049,187 (UGI Book V, Ex. E, p. 1).

Q. WHAT IS A SCALE BACK OF RATES?

A. If the Commission grants an increase less than the amount UGI requested, the Company's proposed rates would be reduced, or scaled back, to produce the revenue requirement allowed by the Commission.

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND FOR THE R/RT AND N/NT CLASSES?

A. I recommend that both the customer charge and usage rates be scaled back such that increase for each customer class is scaled back proportionally to the increase originally proposed by the UGI based on the cost of service study that is ultimately approved.

Q. WHY DO YOU RECOMMEND THAT CUSTOMER CHARGES BE INCLUDED IN ANY SCALE BACK?

A. There are several. First, the proposed increase in the R/RT and N/NT customer charges are larger than increases proposed for the respective usage rates. Therefore, in order to limit the increase in the customer charge applicable to zero and low usage customers, it should be included in the scale back. Second, this recommendation promotes conservation because it causes a larger portion of the customer's bill to be recovered in volumetric rates, thus giving customers more of an incentive to reduce usage. Finally, in the last UGI Electric case, the Commission determined that in spite of the higher customer cost determination in the cost of service study, the customer charges should be reduced for all customers (UGI Electric R-2017-2640058, Order entered October 25, 2018, p. 175).

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND FOR THE DS CLASS?

A. The DS customer charge was not increased under proposed rates, so it should not be included in any scale back. I recommend that the usage rates be scale back but no lower than the present North / Central division usage rate of $2.930 per Mcf.

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND FOR THE LFD CLASS?

A. The LFD customer charge was not increased under proposed rate, so it should not be included in any scale back. I recommend that the usage rates be scale back proportionally to reduce the revenue from this class.

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND FOR THE XD AND INTERRUPTIBLE CLASSES?

A. The customer charges and usage rates were not increased under proposed rate, so they should not be included in any scale back. I recommend that only the surcharges be for these competitive customers be adjusted.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ETHAN H. CLINE

PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

03/2009 - Present

Bureau of Investigation and Enforcement, Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

Fixed Utility Valuation Engineer – Assists in the performance of studies and analyses of the engineering-related areas including valuation, depreciation, cost of service, quality and reliability of service as they apply to fixed utilities. Assists in reviewing, comparing and performing analyses in specific areas of valuation engineering and rate structure including valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design.

06/2008 – 09/2008

Akens Engineering, Inc. - Shiremanstown, Pennsylvania

Civil Engineer – Responsible, primarily, for assisting engineers and surveyors in the planning and design of residential development projects

10/2007 – 05/2008

J. Michael Brill and Associates - Mechanicsburg, Pennsylvania

Design Technician – Responsible, primarily, for assisting engineers in the permit application process for commercial development projects.

01/2006 – 10/2007

CABE Associates, Inc. - Dover, Delaware

Civil Engineer – Responsible, primarily, for assisting engineers in performing technical reviews of the sewer and sanitary sewer systems of Sussex County, Delaware residential development projects.

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Civil Engineering, 2005

- Attended NARUC Rate School, Clearwater, FL
- Attended Society of Depreciation Professionals Annual Conference and Training, 2017, 2018, and 2019

TESTIMONY SUBMITTED:

I have testified and/or submitted testimony in the following proceedings:

1. Clean Treatment Sewage Company, Docket No. R-2009-2121928
2. Pennsylvania Utility Company – Water Division, Docket No. R-2009-2103937
3. Pennsylvania Utility Company – Sewer Division, Docket No. R-2009-2103980
4. UGI Central Penn Gas, Inc., 1307(f) proceeding, Docket No. R-2010-2172922
5. AQUA Clarion Wastewater Operations, Docket No. R-2010-2166208
6. AQUA Claysville Wastewater Operations, Docket No. R-2010-2166210
7. Citizens' Electric Company of Lewisburg, Pa, Docket No. R-2010-2172665
8. City of Lancaster – Bureau of Water, Docket No. R-2010-2179103
9. Peoples Natural Gas Company LLC, Docket No. R-2010-2201702
10. UGI Central Penn Gas, Inc., Docket No. R-2010-2214415
11. Pennsylvania-American Water Company, Docket No. R-2011-2232243
12. Pentex Pipeline Company, Docket No. A-2011-2230314
13. Peregrine Keystone Gas Pipeline, LLC, Docket No. A-2010-2200201
14. Philadelphia Gas Works 1307(f), Docket No. R-2012-2286447
15. Peoples Natural Gas Company LLC, Docket No. R-2012-2285985
16. Equitable Gas Company, Docket Nos. R-2012-2312577, G-2012-2312597
17. City of Lancaster – Sewer Fund, Docket No. R-2012-2310366
18. Peoples TWP, LLC 1307(f), Docket No. R-2013-2341604
19. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2013-2361763
20. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2013-2361764
21. Joint Application, Docket Nos. A-2013-2353647, A-2013-2353649, A-2013-2353651
22. City of Dubois – Bureau of Water, Docket No. R-2013-2350509
23. The Peoples Water Company, Docket No. R-2013-2360798
24. Pennsylvania American Water Company, Docket No. R-2013-2355276
25. Generic Investigation Regarding Gas-on-Gas Competition, Docket Nos. P-2011-227868, I-2012-2320323
26. Philadelphia Gas Works 1307(f), Docket No. R-2014-2404355
27. Pike County Light and Power Company (Gas), Docket No. R-2013-2397353
28. Pike County Light and Power Company (Electric), Docket No. R-2013-2397237
29. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2014-2403939
30. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2014-2420273
31. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2014-2420276
32. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2014-2420279
33. Emporium Water Company, Docket No. R-2014-2402324
34. Borough of Hanover – Hanover Municipal Water, Docket No. R-2014-2428304
35. Philadelphia Gas Works 1307(f), Docket No. R-2015-2465656
36. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2015-2465172
37. Peoples Natural Gas Company – Equitable Division 1307(f), Docket No. R-2015-2465181
38. PPL Electric Utilities Corporation, Docket No. R-2015-2469275
39. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2015-2480934

40. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2015-2480937
41. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2015-2480950
42. UGI Utilities, Inc. – Gas Division, Docket No. R-2015-2518438
43. Joint Application of Pennsylvania American Water, et al., Docket No. A-2016-2537209
44. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2016-2543309
45. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2016-2543311
46. City of Dubois – Company, Docket No. R-2016-2554150
47. UGI Penn Natural Gas, Inc., Docket No. R-2016-2580030
48. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2017-2602627
49. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2017-2602633
50. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2017-2602638
51. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the City of McKeesport, Docket No. A-2017-2606103
52. Pennsylvania American Water Company, Docket No. R-2017-2595853
53. Pennsylvania American Water Company Lead Line Petition, Docket No. P-2017-2606100
54. UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058
55. Peoples Natural Gas Company, LLC – Peoples and Equitable Division 1307(f), Docket Nos. R-2018-2645278 & R-2018-3000236
56. Peoples Gas Company, LLC 1307(f), Docket No. R-2018-2645296
57. Columbia Gas of Pennsylvania, Inc., Docket No. R-2018-2647577
58. Duquesne Light Company, Docket No. R-2018-3000124
59. Suez Water Pennsylvania, Inc., Docket No. R-2018-3000834
60. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the Township of Sadsbury, Docket No. A-2018-3002437
61. The York Water Company, Docket No. R-2018-3000006
62. Application of SUEZ Water Pennsylvania, Inc. Acquisition of the Water and Wastewater Assets of Mahoning Township, Docket Nos. A-2018-3003517 and A-2018-3003519
63. Pittsburgh Water and Sewer Authority, Docket Nos. R-2018-3002645 and R-2018-3002647
64. Joint Application of Aqua America, Inc. et al., Acquisition of Peoples Natural Gas Company LLC, et al., Docket Nos. A-2018-3006061, A-2018-3006062, and A-2018-3006063
65. Implementation of Chapter 32 of the Public Utility Code Regarding Pittsburgh Water and Sewer Authority, Docket Nos. M-2018-2640802 and M-2018-2640803
66. Philadelphia Gas Works 1307(f), Docket No. R-2019-3007636
67. People Natural Gas Company, LLC, Docket No. R-2018-3006818
68. Application of Pennsylvania American Water Company Acquisition of the Steelton Borough Authority, Docket No. A-2019-3006880
69. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the Township of Cheltenham, Docket No. A-2019-3006880
70. Philadelphia Gas Works, Docket No. R-2019-3009016
71. Wellsboro Electric Company, Docket No. R-2019-3008208

72. Valley Energy, Inc., Docket No. R-2019-3008209
73. Citizens' Electric Company of Lewisburg, Pa, Docket Non. R-2019-3008212
74. Application of Aqua America, Inc. et al., Acquisition of the Wastewater System Assets of the East Norriton Township, Docket No. A-2019-3009052
75. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2020-3017850
76. Peoples Gas Company, LLC 1307(f), Docket No. R-2020-3017846
77. Philadelphia Gas Works, Docket No. R-2020-3017206
78. Pittsburgh Water and Sewer Authority, Docket Nos. R-2020-3017951 et al.
79. Columbia Gas of Pennsylvania, Docket No. R-2020-3018835
80. Pennsylvania America Water Company, Docket Nos. R-2020-3019369 and R-2020-3019371
81. PECO Energy Company – Gas Division, Docket No. R-2020-3019829
82. PGW 1307(f), Docket No. R-2021-3023970
83. Peoples Natural Gas Company, LLC 1307(f), Docket No. R-2021-3023965
84. Peoples Gas Company, LLC 1307(f), Docket No. R-2021-3023967
85. UGI Utilities, Inc. – Electric Division, Docket No. R-2021-3023618
86. Columbia Gas of Pennsylvania, Inc., Docket No. R-2021-3024926
87. Duquesne Light Company, Docket No. R-2021-3024750
88. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2021-3025652
89. Pittsburgh Water and Sewer Authority, Docket Nos. R-2021-3024773 et al.
90. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of Lower Makefield Township, Docket No. A-2021-3024267
91. Aqua Pennsylvania Water, Inc. and Aqua Pennsylvania Wastewater, Inc., Docket Nos. R-2021-3027385 and R-2021-3027386
92. Application of Pennsylvania-American Water Company for Acquisition of the Wastewater Collection and Treatment System Assets of the York City Sewer Authority, Docket No. A-2021-3024681
93. City of Lancaster – Bureau of Water, Docket No. R-2021-3026682
94. Application of Aqua America Wastewater, Inc. et al., Acquisition of the Wastewater System Assets of East Whiteland Township, Docket No. A-2021-30246132

I&E Statement No. 4-SR
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Surrebuttal Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Test Year
Present Rate Revenue
Weather Normalization Adjustment
Average Bill Comparison
Scale Back of Rates

TABLE OF CONTENTS

INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ethan H. Cline. My business address is 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation and Enforcement (I&E) as a Fixed Utility Valuation Engineer.

Q. ARE YOU THE SAME ETHAN H. CLINE THAT SUBMITTED DIRECT TESTIMONY ON APRIL 20, 2022?

A. Yes. I submitted I&E Statement No. 4 and I&E Exhibit No. 4 on April 20, 2022.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to make corrections to my direct testimony and address the rebuttal testimony of UGI Utilities, Inc. - Gas Division ("UGI" or "Company") witnesses Christopher R. Brown at UGI Statement No. 1-R, Sherry A. Epler at UGI Statement No. 8-R, and John D. Taylor at UGI Statement No. 11-R. I will also address the rebuttal testimony of Office of

Consumer Advocate ("OCA") witness Jerome D. Mierzwa at OCA Statement No. 3R.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 4-SR contains schedules relating to my testimony.

<u>WEATHER NORMALIZATION ADJUSTMENT</u>

Q. WHAT DID YOU RECOMMEND REGARDING UGI'S PROPOSED WNA?

A. I recommended that UGI's WNA be approved on the condition that a 3% deadband is included. My recommendation maintains consistency with the Commission's previous ruling and with Columbia's existing WNA (I&E St. No. 4, p. 5).

Q. DID THE COMPANY AGREE WITH YOUR RECOMMENDATION?

A. No. The Company disagreed with my recommendation to apply a 3% deadband to the WNA (UGI St. No. 11-R, p. 3).

Q. WHAT REASON DID THE COMPANY PROVIDE FOR NOT AGREEING WITH YOUR RECOMMENDATION?

A. The Company claimed that my recommendation to include a 3% deadband is misplaced and not fully supported with evidence. First, UGI witness Taylor claimed that Commission's Order regarding Columbia Gas of Pennsylvania's ("Columbia") WNA, approving the WNA with a 3% deadband included, does not apply to UGI's proposed WNA. Second, he claimed that customer rates could not be subject to constant adjustment for normal weather variations in every billing cycle because UGI's WNA only applies to the months October through May. Third, Mr. Taylor stated that the primary intent of a WNA mechanism is to adjust for differences measured against normal weather, and he claimed that a deadband should not be included so that the WNA will be easier for customers to understand (UGI St. No. 11-R, pp. 2-3).

Q. DO YOU AGREE THAT SINCE UGI'S PROPOSED WNA IS ADJUSTED ON A MONTHLY BASIS RATHER THAN DAY-TO-DAY BASIS, THE COMMISSION'S RULING DOES NOT APPLY TO UGI'S WNA?

A. Not at all. Whether the adjustment is being made on a day-to-day basis or a monthly basis, the WNA is designed to adjust for variations in temperature and, as I stated on page 4 of I&E Statement No. 4, the Commission was clear in stating that there is no need to reconcile temperature variations that are part of normal business. Specifically, in the same Order (Docket No. R-2020-3018835, Order entered February 19, 2021, pp. 264-265), the Commission determined that the deadband was a reasonable provision because it allows for a range of what is considered "normal" weather in which the Company's Commission-approved rates would be applied without adjustment. In my opinion, this statement applies regardless of whether an adjustment is applied on a daily or monthly basis.

Q. PLEASE RESPOND TO THE COMPANY'S POSITION THAT CUSTOMERS CANNOT BE SUBJECT TO CONSTANT ADJUSTMENT BECAUSE THE PROPOSED WNA MECHANISM ONLY ADJUSTS BILLS ACROSS THE BILLING CYCLE DURING THE MONTHS OF OCTOBER THROUGH MAY.

A. Mr. Taylor appears to be playing semantics with this position. Natural gas heating customers, who would be subject to a WNA, would not have adjustments occur outside of the heating season of October through May because customers generally don't heat their homes or businesses outside of those months. As described in my direct testimony, without a deadband, customers would be subject to constant adjustment for normal weather variations is to illustrate that temperature naturally has variations and that "normal" weather should be a range rather than a single temperature point. As discussed above, the Commission determined a 3% deadband was reasonable in its Columbia Order.

Q. DO YOU AGREE THAT A DEADBAND ADDS AN ADDITIONAL LEVEL OF COMPLEXITY THAT CUSTOMERS WOULD NOT UNDERSTAND?

A. No. As has been established, both Columbia and Philadelphia Gas Works have established a WNA with a deadband and I am unaware of any problems regarding customers being able to understand their billing as a result of the WNA with a deadband. Additionally, Mr. Taylor did not provide any evidence that customers who pay bills under the deadbanded WNA have had problems understanding their bills. Therefore, this claim should be disregarded.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION?

A. No. For the reasons discussed above, I continue to recommend the proposed WNA be approved on the condition that a 3% deadband is included.

<u>PRESENT RATE REVENUE</u>

Q. WHAT AMOUNT PRESENT RATE REVENUE IS THE COMPANY REFLECTING FOR THE FPFTY ENDING SEPTEMBER 30, 2023?

A. UGI is reflecting approximately $1,062,721,000 of present rate revenue including gas costs, surcharges, and other operating revenues (UGI Ex. A FPFTY Rebuttal, Sch. D-1).

Q. DO YOU AGREE WITH THE CLAIMED $1,062,721,000 OF PRESENT RATE REVENUE FOR THE FPFTY?

A. No. As described below, I have determined that UGI has understated its present rate revenue in the FPFTY and I am recommending a revised increase of approximately $13,660,000 from $1,062,721,000 to $1,076,381,000. My recommendation is based on two adjustments to UGI's claimed $662,174,239 of present rate revenue (not including gas costs) in the FPFTY and a correction to my 15-year regression analysis as discussed below.

Q. WHAT IS THE BASIS OF YOUR TWO ADJUSTMENTS TO UGI'S PRESENT RATE REVENUE CLAIM IN THE FPFTY?

A. First, I will address the rate class R/RT heating customer usage decline reflected in the FPFTY that was projected beyond the end of the FPFTY. Second, I will address the overall regression analysis performed by UGI to project usage per R/RT heating customer to determine sales volumes.

<u>R/RT HEATING CUSTOMER USAGE DECLINE</u>

Q. DID YOU AGREE WITH THE CLAIMED $1,062,724,000 OF PRESENT RATE REVENUE FOR THE FPFTY IN YOUR DIRECT TESTIMONY?

A. No. As described in my direct testimony and below, I recommended two adjustments to UGI's claimed $1,062,724,000 of present rate revenue (I&E St. No. 4, pp. 6-22).

<u>R/RT HEATING CUSTOMER POST FPFTY USAGE DECLINE</u>

Q. HOW DID THE COMPANY PROJECT USAGE DECLINE IN THIS CASE?

A. The Company projected the usage per customer decline six months beyond the end of the FPFTY test year in UGI Book II, Attachment SDR-RR-11(a) to justify a lower average usage per residential heating customer during the FPFTY in the proof of revenue.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS CONCERNING THE COMPANY'S "ANNUALIZATION" OF POST FPFTY USAGE DECLINES?

A. I recommended that the usage decline beyond the end of the FPFTY be rejected. There is no justification for allowing the level of usage projected at the end of the FPFTY to be "annualized" by projecting usage out to March 2024. The inclusion of such an "annualization" will benefit the Company to the detriment of customers (I&E St. No. 4, p. 12).

Q. WHAT AVERAGE USAGE PER R/RT CUSTOMER DID YOU RECOMMEND SO THAT THE POST FPFTY DECLINE IS ELIMINATED?

A. I recommended that the average usage per R/RT customer be increased by 0.1307 Mcf per customer per year (I&E Ex. No. 4, Sch. 2, line 5). This 0.1307 Mcf per customer per year was determined by subtracting the 87.9625 Mcf per customer at the end of the FPFTY from the 87.8318 Mcf per customer as of March 2024 as shown on UGI Book II, Attachment SDR-RR-11(a), page 9. (I&E St. No. 4, p. 12).

Q. HOW MUCH DID GAS VOLUMES INCREASE IF THE AVERAGE USAGE PER R/RT CUSTOMER IS INCREASED BY 0.1307 PER CUSTOMER PER YEAR?

A. As described in I&E St. No. 4, pp. 13, gas volumes increase by 77,061 Mcf (589,601 x 0.1307). This 142,926 Mcf of gas was determined by multiplying the 0.1307 per customer per year times 589,601 R/RT heating customers shown on UGI Book III, Exhibit SAE-7(a).

Q. WHAT INCREASE IN PRESENT RATE USAGE REVENUE DID YOU RECOMMEND IF THE AVERAGE USAGE PER R/RT HEATING CUSTOMER IS INCREASED BY 0.1307 MCF PER CUSTOMER PER YEAR?

A. As described in I&E St. No. 4, p. 13, present rate usage revenue increases by $316,752 (I&E Ex. No. 4, Sch. 2, line 6).

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO REJECT THE POST FPFTY USAGE DECLINE, DID YOU ALSO RECOMMEND COMMENSURATE ADJUSTMENTS TO GAS COSTS AND SURCHARGES?

A. Yes. These adjustments are described on I&E St. No. 4, pp. 13-14.

Q. WHAT IS THE TOTAL INCREASE IN PRESENT RATE REVENUE IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE DISTRIBUTION VOLUME BY 77,061 MCF?

A. As stated on I&E St. No. 4, pp. 14-15, present rate revenue increases $427,964 (I&E Ex. No. 4, Sch. 2, line 29).

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION TO REMOVE THE PROJECTED POST-FPFTY USAGE DECLINE FOR THE R/RT HEATING CLASS?

A. Yes. The Company believes that my recommendation should be rejected (UGI St. No. 8-R, p. 4-5).

Q. WHAT REASONS DOES THE COMPANY PROVIDE TO REJECT YOUR RECOMMENDATION TO REMOVE THE PROJECTED POST-FPFTY DECLINE?

A. The Company provided several reasons to reject my recommendation. First, the Company claims that its analysis does not incorporate post-FPFTY usage decline. Second, the Company argues that it is proper to incorporate post-FPFTY to annualize usage for the FPFTY using the annual period ending March 30, 2024. Third, the Company claims that its methodology incorporates usage reductions already in place at the end of the FPFTY and annualizes that impact. Finally, the

Company provided what it believes to be justification for projecting usage decline six months beyond the end of the FPFTY by attempting to capture customer heating equipment upgrades that occur in the FPFTY but prior to the next heating season.

Q. IS THE COMPANY'S TESTIMONY IN UGI STATEMENT NO. 8-R CONTRADICTORY REGARDING POST-FPFTY USAGE DECLINE?

A. Yes. On UGI Statement No. 8-R, page 3, lines 11-12, the Company indicates that it does not incorporate post-FPFTY usage decline; however, on line 21 of the same page, the Company stated that it "must project monthly use through the end of March 31, 2024 to develop an annualized value for us per customer." This is the exact opposite of the Company's statement that it does not incorporate post-FPFTY usage decline.

Q. IS THE COMPANY'S CLAIM THAT POST-FPFTY DECLINES SHOULD BE INCLUDED AS A NORMAL FPFTY RATEMAKING ADJUSTMENT VALID?

A. No. Post-FPFTY usage declines occur after the end of the FPFTY, not during the FPFTY; therefore, there is no sound ratemaking reason that data outside the test year data should be considered in a base rate proceeding.

Q. IS THE COMPANY'S CLAIM THAT REACHING BEYOND THE END OF THE FPFTY IS NECESSARY TO ANNUALIZE THE USAGE FOR CUSTOMERS AS OF SEPTEMBER 30, 2023 VALID?

A. No. The Company's claim is baseless. The Company's own analysis contradicts this unfounded claim. As shown on UGI Book II, Attachment SDR-RR-11(a), each monthly usage projection is a rolling average of the previous twelve months. Therefore, the Company's usage projection of 87.9625 Mcf per R/RT heating customer per year as of September 30, 2023 already includes the usage declines for each previous month of the FPFTY, including the FPFTY winter heating season. As such, the projected 87.8138 Mcf per R/RT heating customer as of March 31, 2024 should not be used to establish rates in this proceeding.

Q. DOES THIS CLEARLY SHOW HOW THE COMPANY'S EXAMPLE UNDERSTATES REVENUE IN THE FPFTY?

A. Yes. As shown on UGI Book II, Attachment SDR-RR-11(a), the Company's own usage projections in the FPFTY range from 88.1221 Mcf to 87.9625 Mcf per R/RT heating customer per year, which on average would be approximately 88.04 (88.1221 + 87.9625)/ 2)) Mcf in the FPFTY. Yet the Company erroneously believes that the usage per customer in the FPFTY should be annualized all the way down to 87.8138 Mcf per R/RT heating customer per year. If the Company's proposal is accepted, it will be permitted to base rates on a projected usage that is lower than its own projected usage and allow UGI to collect a revenue windfall.

Q. DOES THE EXAMPLE PROVIDED BY THE COMPANY IN WHICH A CUSTOMER INSTALLS A NEW FURNACE ACTUALLY SUPPORT YOUR RECOMMENDATION INSTEAD?

A. Yes, it does. The Company provided an example in which a customer installs a new furnace prior to the end of the FPFTY that are in place but not yet measured via observed and billed usage (UGI St. No. 8-R, p. 4). In this example, the Company believes the customer's usage <u>must</u> be annualized to capture the usage after September 30, 2023, beyond the end of the FPFTY. Under this scenario, the Company would bill that customer for 87.8138 Mcf of usage during the twelve months of the FPFTY. Thus, charging customers rates that anticipate expected post-FPFTY heating season conservation measures has the effect of penalizing customers for conservation efforts before those efforts are even undertaken.

Q. DID THE COMPANY PROVIDE ANY SUPPORT FOR ITS POSITION THAT WOULD CAUSE YOU TO CHANGE YOUR RECOMMENDATION?

A. No. I continue to believe that including post-FPFTY usage projections to determine use per customer is improper. Therefore, I continue to recommend that the inclusion of post-FPFTY projections in the usage per customer analysis be denied.

Q. DID THE COMPANY PROVIDE ANY VALID REASONS FOR INCLUDING POST FPFTY USAGE DECLINES WHEN DETERMINING THE USAGE AT THE END OF THE FPFTY?

A. No. Therefore, present rate revenue should be increased $427,964 from $662,174,239 to $662,602,203 (I&E St No. 4, p. 14).

<u>R/RT HEATING CUSTOMERS – REGRESSION ANALYSIS</u>

Q. WHAT IS THE SECOND ADJUSTMENT YOU RECOMMENDED TO THE COMPANY'S PROJECTED USAGE FOR R/RT HEATING CUSTOMERS?

A. As described on pages 14-22 of I&E Statement No. 4, my second recommendation addresses the use of 18 years of data to project usage per customer that is used to project the 87.8 Mcf per year of usage for the R/RT heating customer claimed by the Company.

Q. WHAT TIME PERIOD OF DATA DID YOU RECOMMEND IN THIS CASE TO PROJECT THE AVERAGE USAGE PER R/RT CUSTOMER?

A. I recommended the most recent 15-years of data as proposed in UGI's previous base rate case to project the average use per R/RT heating customer in this case. (I&E St. No. 4, p. 16).

Q. WHY DID YOU RECOMMEND THE USE OF 15 YEARS TO PROJECT THE AVERAGE USAGE PER R/RT CUSTOMER FOR THE FPFTY?

A. I recommended the use of 15-years of data for several reasons. First, a fifteen-year time period is consistent with the reasons UGI described for utilizing a multi-year regression period. Second, the 15-year time period is consistent with the time period used for the Company's weather normalization adjustment. Third, the Company has supported the use of 15-year time period for its regression analysis in its previous cases. Finally, I stated that I believed that usage and temperature data older than 15 years is not representative of recent usage trends on which to base the usage projection (I&E St. No. 4. pp. 16).

Q. WHAT IS THE TOTAL INCREASE IN PRESENT RATE REVENUE YOU RECOMMENDED AS A RESULT OF YOUR 15-YEAR REGRESSION ANALYSIS, INCLUDING ASSOCAITED CHANGES TO PURHCASED GAS AND OTHER SURCHARGES

A. I recommended present rate revenue increase by $14,648,202 from $662,174,239 to $676,822,441 (I&E Ex. No. 4, p. 21).

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATION TO USE A 15-YEAR PERIOD TO PROJECT R/RT HEATING CUSTOMER USAGE?

A. Yes. The Company stated that it does not agree with my proposed adjustment concerning the Company's regression analysis (UGI St. No. 8-R, pp. 5-6).

Q. DID THE COMPANY AGREE THAT YOUR ANALYSIS IS CONSISTENT WITH THE COMPANY'S REASONS FOR UTILIZING A MULTI-PERIOD REGRESSION ANALYSIS?

A. Yes. However, the Company did not agree with the rest of my rationale for using a 15-year regression period. (UGI St. No. 8-R, p. 6).

Q. WHAT RATIONALE DID THE COMPANY PROVIDE FOR REJECTING YOUR RECOMMENDATION TO UTILIZE 15 YEARS OF DATA TO PROJECT R/RT HEATING CUSTOMER USAGE?

A. First, the Company opposed the comparison of the time periods to determine weather normalization and use per customer (UGI St. No. 8-R, p. 6). Second, the Company disagreed with my assessment that the Company supported the use of 15-years for its regression analysis in its previous cases. Third, the Company stated that it is not aware of a regulatory "stale" standard that is appropriate for ratemaking and thus does not agree with my assertion that the fifteen-year period does not include data that is no longer representative of more recent trends UGI St. No. 8-R, p. 9).

Q. WHY DID THE COMPANY OPPOSE THE COMPARISON OF WEATHER NORMALIZATION AND USE PER CUSTOMER?

A. The Company opposed the comparison of weather normalization and use per customer because "the two factors require independent assessment which can then be utilized to support proper ratemaking design, claims and conclusion." (UGI St. No. 8-R, p. 7).

Q. DID YOU ACKNOWLEDGE THAT WEATHER NORMALIZATION AND USE PER CUSTOMER ARE DIFFERENT TYPES OF ANALYSES IN YOUR DIRECT TESTIMONY?

A. Yes. I stated on page 17 of I&E Statement No. 4 that the analyses performed to determine normalized temperatures and use per customer are different types of analyses.

Q. DOES ACKNOWLEDGING THAT WEATHER NORMALIZATION AND USE PER CUSTOMER ARE SEPARATE FACTORS NEGATE YOUR COMPARISON OF THE ASSESSMENT TIME PERIODS BETWEEN THE TWO FACTORS?

A. No. This acknowledgement does not erase the fact that the two factors are similar in that they each are based on highly variable sets of data analyzed over an extended period of time. That the Company uses a fifteen-year time period, rather than longer periods of 20- or 30-years, to normalize data as highly variable as weather shows that it is not necessary to use "all available data" to provide an accurate estimation of use per customer as the Company suggests.

Q. WHY DID THE COMPANY DISAGREE WITH YOUR ASSESSMENT THAT THE COMPANY SUPPORTED THE USE OF 15-YEARS FOR ITS REGRESSION ANALYSIS IN ITS PREVIOUS CASES?

A. The Company referred to the two cases following the 2019 UGI Gas merger case in which it used "all available common years" which amounted to 16 and 18 years of data. It further stated that this approach is used in an effort to smooth out transient aberrations that may occur year-to-year for various reasons and best capture long-term trends influencing use per customer. (UGI St. No. 8-R, pp. 7-8).

Q. DID THE COMPANY PROVIDE ANY EXPLANATION WHY CONTINUALLY ADDING YEARS TO ITS ANALYSIS IN SUBSEQUENT BASE RATE CASES IS NEEDED TO SMOOTH OUT "TRANSIENT YEAR-TO-YEAR ABERRATIONS AND CAPTURE LONG-TERM TRENDS"?

A. No. In its 2019 case, the use of 15-years was a sufficient data set to smooth out the transient year-to-year aberrations and capture long-term trends. The Company failed to provide any explanation or rationale for why the existence of additional data suddenly means that 15-years is no longer enough data to smooth out any aberrations or capture long-term trends.

Q. IS IT REASONABLE TO UTILIZE ALL AVAILABLE DATA TO PROJECT THE AVERAGE USAGE PER R/RT HEATING CUSTOMERS?

A. No. As I stated above, in the 2019 base rate case, the Company believed that using 15 years of data was "statistically valid." As described above, now the Company believed that using 16 years of data is "statistically valid." Furthermore, as I stated on page 18 of I&E Statement No. 4, the Company, in its 2019 case, also supported utilizing 15 years of data because the use of 15 years of data is recommended by the American Gas Association and the US Energy Information Association.

Q. DID THE COMPANY PROVIDE ANY SUPPORT FROM THE AMERICAN GAS (AGA) ASSOCIATION OR THE US ENERGY INFORMATION ASSOCIATION (US-EIA) TO SUPPORT USING 18 YEARS OF DATA?

A. No. The Company made no mention of the AGA or the US-EIA to support its current proposed used of 18-years in its direct or rebuttal testimony.

Q. DID THE COMPANY EXPLAIN WHY CONTINUALLY ADDING USAGE DATA TO ITS ANALYSIS IN EACH SUBSEQUENT BASE RATE CASE IS REASONABLE?

A. Yes. The Company stated that it is not aware of a regulatory "stale" standard that is appropriate for ratemaking and thus does not agree with my assertion that data older than 15-years is not representative of recent usage trends and is therefore stale. (UGI St. No. 8-R, p. 9).

Q. IS THE COMPANY'S REFERENCE TO A REGULATORY "STALE" STANDARD DISINGENUOUS?

A. Yes. While there is no written standard regarding the concept of stale data, in practice, the idea of not using data because it is stale is common in base rate cases. The Company does not use "all data available" when determining ratemaking items including, but not limited to, materials and supplies (determined using 13-months of data), forfeited discounts (determined using a three-year average of data), and weather normalization (determined using 15-years of data), because the data outside of the respective time periods is not indicative of current trends. As an example, if there were data from 30 years ago, I would assume that the Company would consider all of that data valid and useful for usage trend analysis.[1] This is simply inaccurate as 30 years of data would encompass large gains in efficiency developments for appliances and home heating technology and even changes in the heating quality of the gas with the introduction of shale gas inside that time period. These type of large magnitude changes impacting gas usage simply cannot be expected to recur going forward, so including the many years of

[1] This assumption is supported by the Company's reference to UGI Gas (former South Rate District) 2016 base rate case in which the Rate R/RT residential use per customer regression was based on a period of nearly 21 years of data. The use of 21 years of data was also opposed by I&E.

data that reduced customer usage due to significant changes should ultimately drop out of the trend analysis to assure that usage projection declines are not overstated going forward. Therefore, there is no justification for adding data simply because its available.

Q. WHAT DID THE COMPANY STATE REGARDING THE INTENT OF YOUR ANALYSIS?

A. On page 9 of UGI Statement No. 8-R, the Company stated that my approach "appears only intended to establish a result which would increase Rate R/RT residential heating use per customer and should be rejected." It supported this accusation by claiming that the data I referred to as stale is related to a downward trend in usage and that the several trends that were upwards in magnitude (2010-2011, 2012-2013, and 2016-2018, specifically) were not excluded.

Q. PLEASE RESPOND.

A. The Company's accusation is false and without merit. While the Company is correct that I could have recommended a five-year period to determine use per customer, I did not do this because, as I stated on I&E Statement No. 4, p. 17, "[a] fifteen-year period remains long enough to smooth out short-term variations and capture the underlying long-term use per customer trends while having the added benefit of not including data that is no longer representative of more recent trends." This statement is consistent with the Company's stated goal of "transient year-to-year aberrations and capture long-term trends" as discussed above. The Company's reference to upward trends in usage in 2010-2011, 2012-2013, and 2016-2018 are also false because, as UGI files additional rate cases over the years, those time periods will eventually no longer be included as they fall out of the data range that should be considered recent. It appears that the Company came to this conclusion and calls into question whether the reason the Company wants to include "all available data" is to smooth out aberrations, as it claims, or to ensure the higher usage in October 2003 is always included so that the use per customer trend decreases more and, thus, increases customer rates.

Q. WHAT DID THE COMPANY STATE REGARDING I&E'S USE PER CUSTOMER RECOMMENDATIONS IN PRIOR CASES?

A. Ms. Epler claimed that I&E's methodology for determining use per customer has varied in UGI Gas's most recent cases, claiming that I used a 5-year and 1-month period in the current case, a 15-year period in the 2020 UGI base rate case, and a 10-year regression period during the Company's 2019 base rate case. (UGI St. No. 8-R, p. 12).

Q. IS THE COMPANY'S DESCRIPTION OF I&E'S PRIOR RECOMMENDATIONS ACCURATE?

A. No. As I discuss below, the 5-year and 1-month analysis was provided in error and the correct 15-year analysis is described below. Though I was not the witness for the 2019 base rate case, I am aware that I&E proposed using a 10-year regression period in that case.

Q. IS THE COMPANY'S CRITICISM OF I&E'S PRIOR RECOMMENDATIONS VALID?

A. No. The time periods selected by I&E were based upon the specific circumstances of each case.

Q. DID THE COMPANY INTRODUCE ANY OTHER ISSUES WITH YOUR ANALYSIS?

A. Yes. On page 10 of UGI Statement No. 8-R, UGI witness Epler correctly indicated that the support for my analysis was based upon 61 months (or 5 years and one month) instead of 180 months (or 15-years) as I described in my direct testimony and above. Pages 11-12 of UGI Statement No. 8-R were dedicated to a discussion of the statistical analysis and P-values of the previous, incorrect, analysis. My intention in Direct Testimony was to use 15-years; however, UGI is correct that I utilized the incorrect time period in my analysis. As such, I would like to correct my recommendation so that it is based on a 15-year data set instead of 5-years and 1 month as I discuss below. For ease of reference, I will discuss this adjustment based on the Company's recommendation.

Q. WHAT IS THE UPDATED USAGE PER R/RT HEATING CUSTOMER THAT YOU ARE RECOMMENDING?

A. I recommend a projected average use per customer for the FPFTY ending September 30, 2023 of approximately 90.0968 Mcf per year (I&E Ex. No. 4-SR, Sch. 1, p. 4). As shown on I&E Exhibit No. 4-SR, Schedule 1, this use per customer is based on a regression analysis of 180 months, or 15-years. The regression results are shown on I&E Exhibit No. 4-SR, Schedule 2. This results in an increase of 2.283 (90.0968-87.8138) Mcf per R/RT customer per year.

Q. HOW MUCH DO GAS VOLUMES INCREASE IF THE AVERAGE USAGE PER R/RT CUSTOMER IS INCREASED BY 2.283 MCF PER CUSTOMER PER YEAR?

A. Gas volumes increase by 1,346,059 Mcf (589,601 X 2.283). This 1,346,059 Mcf of gas was determined by multiplying the 2.283 Mcf per customer per year times 589,601 R/RT heating customers shown on UGI Book III, Exhibit SAE-7(a).

Q. HOW MUCH DOES PRESENT RATE USAGE REVENUE INCREASE IF THE AVERAGE USAGE PER R/RT HEATING CUSTOMER IS INCREASED BY 2.283 MCF PER CUSTOMER PER YEAR?

A. If my recommendation to use the FPFTY average usage is approved, present rate usage revenue increases by $5,532,841 (I&E Ex. No. 4-SR, Sch. 3, line 6). This $5,532,841 of present rate R/RT revenue was determined by multiplying the

1,346,059 Mcf of gas described above times the present usage rate of $4.1104 per Mcf shown on UGI Book V, Exhibit E, p. 2. The result would be to increase the Company's claimed present rate revenue for residential customers by $5,532,841 from $662,174,239 to $667,707,080.

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE REVENUE BY $5,532,841 TO $667,707,080 SHOULD THERE BE A CORRESPONDING INCREASE IN PURCHASED GAS REVENUE AND EXPENSES?

A. Yes. Under present rates, the PGC volumes equal approximately 85.47% of total usage volumes (I&E Ex. No. 4-SR, Sch. 3, line 11, col. A). Therefore, increasing total R/RT sales volumes by 1,346,059 Mcf increases the PGC by 1,150,450 Mcf (1,346,059 Mcf X 0.8547) (I&E Ex. No. 4-SR, Sch. 3, line 10 col. B). This results in an increase in PGC revenue and expenses of $7,721,028 (1,150,450 Mcf X the $6.2767 per Mcf PGC rate) (I&E Ex. No. 4-SR, Sch. 3, line 10, col. D).

Q. IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE REVENUE BY $5,532,841 TO $667,707,080 SHOULD THERE BE A CORRESPONDING INCREASE IN OTHER SURCHARGES?

A. Yes. Since the following surcharges are based upon volumes or revenue, they would each increase if the Commission accepts my recommendation to eliminate the post FPFTY usage decline and 15-year regression analysis. Under present rates, the Merchant Function Charge will increase by $156,696 to $6,348,013 (I&E Ex. No. 4-SR, Sch. 3, line 14, col. 14). The Gas Procurement Charge will increase by $75,930 to $3,070,682 (I&E Ex. No. 4-SR, Sch. 3, line 17, col. D). The Universal Service Program rider will increase by $86,979 to $17,623,877 (I&E Ex. No. 4-SR, Sch. 3, line 20, col. D). The Energy and Conservation Efficiency Rider will increase by $279,576 to $11,081,427 (I&E Ex. No. 4-SR, Sch. 3, line 23, col. D).

Q. DOES YOUR RECOMMENDATION TO INCREASE USAGE PER R/RT HEATING CUSTOMER INCLUDE THE VOLUMES AND DOLLARS OF YOUR FIRST RECOMMENDATION CONCERNING POST FPFTY R/RT HEATING USAGES?

A. Yes. As I stated on page 21 of I&E Statement No. 4, the adjustments in my second recommendation are inclusive of the adjustment I described regarding the inclusion of post FPFTY usage data.

Q. DID YOUR UPDATED ANALYSIS PRODUCE A NEW SET OF P-VALUES?

A. Yes. As shown on I&E Exhibit No. 4-SR, Schedule 2, all of the P-values, except for X Variable 3 are below the 0.05 threshold.

Q. ACCORDING TO THE COMPANY, IS YOUR ANALYSIS "STATISTICALLY SIGNIFICANT"?

A. No. However, "statistical significance" should not be the only factor in determining whether a use per customer adjustment is reasonable. As I stated above, conditions that determine use per customer change over time and should no longer be considered representative of current trends. A 50-year regression analysis would likely produce a result that is "statistically significant," but it is not reasonable to assume that data and usage trends from the 1960's, 1970's, and 1980's is indicative of customer usage patterns in 2022 and 2023.

Q. WHAT IS THE TOTAL INCREASE IN PRESENT RATE REVENUE IF THE COMMISSION ACCEPTS YOUR RECOMMENDATION TO INCREASE R/RT PRESENT USAGE RATE DISTRIBUTION VOLUME BY 1,346,059 MCF?

A. Present rate revenue increases by $13,659,652 from $662,174,239 to $675,833,892 (I&E Ex. No. 4-SR, Sch. 3, line 29, col. D). This represents a decrease of $988,550 from the $676,822,441 present rate revenue recommendation shown on I&E Statement No. 4, p. 21 to $675,833,892. As stated above, including gas costs, this represents a revised increase of approximately $13,660,000 from $1,062,721,000 to $1,076,381,000.

AVERAGE BILL COMPARISON

Q. DID THE COMPANY MAKE ANY CLAIMS IN ITS DIRECT TESTIMONY REGARDING THE COMPARISON OF CURRENT RESIDENTIAL RATES TO HISTORIC RESIDENTIAL RATES?

A. Yes. On page 7 of UGI Statement No. 1, the Company claimed that "the Company's average customer bills are less than they were in 2008."

Q. IS THIS ARGUMENT PERSUASIVE?

A. No. As I stated in my Direct Testimony, his claim should be disregarded because it is unsupported and misleading because the comparison is driven largely by the Gas Cost Rate, which is outside of UGI's control (I&E St. No. 4, pp. 24-25).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Yes. The Company disagreed that the Gas Cost Rate should not be considered in the comparison of average bills in the context of a base rate case. The Company also disagreed with my statement that UGI has no control over the gas costs paid by UGI customers (UGI St. No. 1-R, pp. 14-15).

Q. WHY DOES UGI BELIEVE GAS COSTS SHOULD BE INCLUDED IN THE COMPARISON OF AVERAGE BILLS?

A. UGI witness Brown stated that the average bill comparison was focused on customer affordability, and, from that perspective, it is not logical to do a partial bill comparison because that is not how customers experience a gas bill. He further stated that this analysis shows a "data point showing that the customer's bill as a result of this case will still be within the range of their historic experience." (UGI St. No. 1-R, p. 14).

Q. DO YOU AGREE WITH THE STATEMENT THAT THE CUSTOMER'S BILL AS A RESULT OF THIS CASE WILL STILL BE WITHIN THE RANGE OF THE CUSTOMER'S HISTORIC EXPERIENCE?

A. No. This statement will only be accurate if the cost of gas does not increase, and gas costs to customers have increased substantially over just the past year. Furthermore, cherry picking the year 2008 when gas costs were at an all-time high to indicate cost stability is not how a consumer evaluates their month-to-month costs as monthly expenses from 14 years ago would be substantially different and incomparable to current costs and income. It would be illogical to assume that UGI bases its current budgets and cost expectations on conditions 14 years in the past, and it is equally illogical to do so and make this comparison on the utility customer's basis.

Q. HOW DOES MR. BROWN CLAIM THAT UGI IS ABLE TO CONTROL THE COST OF GAS?

A. On page 15 of UGI Statement No. 1-R, Mr. Brown lists a number of methods that UGI uses to control the cost of gas, none of which are able to be assessed or adjusted in the course of a base rate case. In fact, on March 1, 2021, the UGI gas rate was $4.2426 per Mcf, and as of March 1, 2022, the UGI gas rate is $6.2767 per Mcf, an increase of 47.9% in one year ($6.2767-$4.2426/$4.2426), which is hardly indicative of controlled gas costs.

Q. DO YOU AGREE WITH THE COMPANY THAT IT TAKES STEPS TO REDUCE GAS COSTS FOR CUSTOMERS?

A. Yes, but that is not the same thing as having control over the final cost of gas and the total cost of gas on the customer's bill. It should also be noted that the Company also takes steps to increase gas costs, such as including the cost of LNG and additional cost of capacity to increase supplies and reliably.

Q. DO THE METHODS OF AFFECTING THE COST OF GAS IN THE 1307(F) PURCHASED GAS COST FILING LISTED BY MR. BROWN GIVE UGI COMPLETE CONTROL OVER THE COST OF GAS?

A. No. The despite UGI's methods to affect it, the cost of gas is still controlled by the prices set by the natural gas suppliers, the natural gas market, and the need for capacity to deliver the gas to UGI on peak days which are not under the control of the Company.

Q. DO YOU WISH TO CHANGE YOUR RECOMMENDATION?

A. No. Providing customers an average bill comparison in the context of a base rate case that includes the cost of gas without mentioning the cost of gas and its effects on the average bill is misleading and I continue to recommend it be disregarded.

SCALE BACK OF RATES

Q. WHAT SCALE BACK METHODOLOGY DID YOU RECOMMEND FOR THE R/RT AND N/NT CLASSES?

A. I recommended that both the customer charge and usage rates be scaled back such that increase for each customer class is scaled back proportionally to the increase originally proposed by UGI based on the cost of service study that is ultimately approved.

Q. WHAT SCALE BACK METHODOLOGY DID YOU RECOMMEND FOR THE DS CLASS?

A. The DS customer charge was not increased under proposed rates, so it should not be included in any scale back. I recommended that the usage rates be scaled back but no lower than the present North / Central division usage rate of $2.930 per Mcf.

Q. WHAT SCALE BACK METHODOLOGY DID YOU RECOMMEND FOR THE LFD CLASS?

A. The LFD customer charge was not increased under proposed rate, so it should not be included in any scale back. I recommended that the usage rates be scaled back proportionally to reduce the revenue from this class.

Q. WHAT SCALE BACK METHODOLOGY DID YOU RECOMMEND FOR THE XD AND INTERRUPTIBLE CLASSES?

A. The customer charges and usage rates were not increased under proposed rate, so they should not be included in any scale back. I recommended that only the surcharges be for these competitive customers be adjusted.

Q. DID THE COMPANY ADDRESS YOUR RECOMMENDATIONS?

A. Not directly. However, UGI witness Epler, on page 27 of UGI Statement No. 8-R, stated that the increases by classes as proposed by the Company should be adjusted proportionate across all classes and that the scale back should only apply to the distribution charge portion of the Company's proposed rates, in contradiction of my recommendation to also scale back the customer charge, because it is supported by the customer cost analysis.

Q. DO YOU AGREE WITH THE COMPANY'S RECOMMENDATION?

A. No. As I stated in direct testimony and above, the customer charge should be included in the scale back of rates. Reducing the customer charge despite the support is consistent with Commission precedent in the UGI Utilities, Inc. – Electric base rate case at Docket No. R-2017-2640058 (I&E St. No. 4, pp.27-28).

The Company provided no evidence or rationale provided in this case for reversing the Commission's prior decision concerning customer charges in that case.

Q. DID ANY OTHER PARTIES ADDRESS YOUR SCALE BACK RECOMMENDATION?

A. Yes. OCA witness Mierzwa opposed my recommendation because it is based on the Company's cost of service study which used the Average and Excess methodology as opposed to the cost of service study he proposed which employs the Peak and Average methodology (OCA St. No. 2R, p. 3).

Q. DO YOU OPPOSE THE OCA'S RECOMMENDED PEAK AND AVERAGE COST OF SERVICE STUDY?

A. I did not perform an analysis of the OCA's Peak and Average cost of service study. However, in general, the Peak and Average methodology for performing a cost of service study is also reasonable. Therefore, I neither support nor oppose OCA's proposed cost of service study.

Q. DO YOU WISH TO CHANGE YOUR SCALE BACK RECOMMENDATION?

A. No. I continue to recommend that the customer charge and usage rates be scale back only for those rate classes that have a proposed increase. I would like to add, however, that this scale back should be based on whichever cost of service study that the Commission deems most reasonable in this case.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 5
Witness: Esyan A. Sakaya

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Direct Testimony

of

Esyan A. Sakaya

Bureau of Investigation and Enforcement

Concerning:

Rate Base
Utility Plant in Service
Annual Depreciation
Accumulated Depreciation Expense
Reporting Requirements

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INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Esyan A. Sakaya. My business address is 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission ("Commission") in the Bureau of Investigation and Enforcement ("I&E") as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to evaluate UGI Utilities, Inc. - Gas Division's ("UGI" or "Company") request for an annual increase in operating revenue of approximately $82,700,000 using the Fully Projected Future Test Year ("FPFTY") ending September 30, 2023 (UGI Gas Book No. 1, p. 6). My testimony will address issues related to plant in service, proposed rate base, annual depreciation expense, accumulated depreciation, and reporting requirements.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 5 contains schedules relating to my testimony.

<u>RATE BASE</u>

Q. WHAT IS RATE BASE?

A. Rate base is the depreciated original cost of a utility's investment in plant a utility has in place to serve customers plus other additions and deductions that the Commission determines to be necessary in order to keep the utility operating and providing safe and reliable service to its customers.

Q. HOW IS THE DEPRECIATED ORIGINAL COST OF PLANT-IN-SERVICE AT THE END OF THE TEST YEAR DETERMINED?

A. The depreciated original cost is equal to the original cost of the utility plant-in-service that is projected to be used and useful in the provision of service to the customers, <u>less</u> the depreciation reserve as adjusted by other items such as salvage value and removal costs. The FPFTY depreciated original cost claimed by the Company in this proceeding for UGI is $3,723,465,000 (UGI Book V, Ex. A - Fully Projected, Sch. C-1, ln.3). The $3,723,465,000 is based upon $5,042,025,000 of original cost less

$1,318,560,000 of accumulated depreciation (UGI Book V, Ex. A - Fully Projected, Sch. C-1, ln. 1-2 and I&E Ex. No. 5, Sch. 1, column B, p-. 1 lines 1, 2 and 4.

Q. WHAT OTHER ADDITIONS AND DEDUCTIONS TO THE DEPRECIATED ORIGINAL COST OF UTILITY PLANT ARE ALLOWED?

A. Some of the additions to the depreciated original cost of a company's investment in utility include materials and supplies, gas inventory, and cash working capital. Some of the deductions include deferred income taxes and customer deposits.

The claimed additions to the Company's depreciated original cost are as follows:

1. Materials and Supplies;
2. Working Capital;
3. Gas Inventory;

The deductions to the depreciated original cost are:

1. ADIT;
2. Customer Deposits.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE BASE FOR THE FPFTY?

A. The Company claims a FPFTY rate base, identified as Total Measure of Value, of $3,169,023,000 (UGI Book V, Ex. A - Fully Projected, Sch. C-1, ln. 9 and I&E Ex. No. 5, Sch. 1, column B, p. 1, line 12).

Q. WHAT RATE BASE DO YOU RECOMMEND IN THIS PROCEEDING?

A. I recommend that rate base be reduced by $145,872,000 to $3,023,151 as a result of my recommended changes to the utility plant-in-service and the accumulated depreciation described below (I&E Ex. No. 5, Sch. 1, column C, p. 1, line 12).

UTILITY PLANT-IN-SERVICE

Q. WHAT IS UTILITY PLANT-IN-SERVICE?

A. Utility plant-in-service comprises all the utility's assets, including both intangible and tangible assets. For example, intangible assets include organization costs, franchise and consents costs, and land and land rights costs. Tangible assets include facilities and equipment. Utility plant-in-service reflects the original cost of the utility's assets before depreciation. UGI also includes a portion of shared corporate costs in its total utility plant in service claim (UGI Book 6, p. II-5).

Q. WHAT IS THE COMPANY'S CLAIMED UTILITY PLANT-IN-SERVICE AT THE END OF EACH TEST YEAR AND HOW MUCH NET PLANT IS PROJECTED TO BE ADDED IN THE FUTURE TEST YEAR AND FULLY PROJECTED FUTURE TEST YEAR?

A. The Company's utility plant-in-service claim for the FTY ending September 30, 2022 is $4,597,404,000 (UGI Ex. A - Future, Sch. C-1, ln. 1). The Company's utility plant-in-service claim for the FPFTY ending September 30, 2023 is $5,042,025,000 (UGI Ex. A - Fully Projected, Sch. C-1, ln. 1). The difference in these two amounts is the total net plant additions from the FTY to the FPFTY, of $444,621,000 ($5,042,025,000 - $4,597,404,000) (I&E Ex. No. 5, Sch. 2, column B, line 13 and column F line 13). The Company's utility plant in service claim for the HTY ending

September 30, 2021 was $4,247,028,000 (UGI Ex A – HTY, Sch. C-1, line 1). The difference between the HTY and the FTY, is $350,376,000 ($4,597,404,000 - $4,247,028,000) (I&E Ex. No. 5, Sch. 2, column B, line 13 and I&E Ex. No. 5, Sch. 4, column D, line 17).

Q. WHAT DO YOU RECOMMEND REGARDING UTILITY PLANT-IN-SERVICE IN THIS PROCEEDING?

A. I recommend that the Company's FPFTY projected plant be reduced by $137,649,000 (I&E Ex. No. 5, Sch. 2, column G, line 13).

Q. WHAT IS THE BASIS FOR YOUR $137,649,000 REDUCTION TO PLANT IN SERVICE?

A. I determined that over the last two base rate cases at Dockets R-2018-3006814 and R-2019-3015162, the Company failed to place into service all the plant projected in those cases. Since rates in those cases were based upon the plant at the end of the FPFTY, this allowed the Company to receive a return on plant not placed into service that established rates in those cases.

Q. HOW DID YOU DETERMINE THE $137,649,000 REDUCTION TO PLANT IN SERVICE IN THIS CASE?

A. As described below, the $137,649,000 was determined by calculating the average percentage of gas plant and common plant projected to be placed into service in the last two base rate cases, then applying those percentage to the corresponding gas and common plant projected to be placed into service in this case. This methodology assumes the Company will only complete a percentage of plant projected to be completed in this case.

Q. WHAT AMOUNT OF FPFTY PLANT WAS PROJECTED TO BE PLACED INTO SERVICE IN THE 2018 CASE?

A. In the 2018 base rate case, the Company projected that it would have $3,950,991,000 of total plant in service by the end of the FPFTY in that case, which was September 30, 2020.[1] This $3,950,991,000 is comprised of $3,726,871,000 of gas plant in service and $224,120,000 of UGI's share of common plant (I&E Ex. No. 5, Sch. 4, p. 1, column B, lines 7 and 14).

Q. WHAT AMOUNT OF FPFTY PLANT WAS ACTUALLY PLACED INTO SERVICE AS OF SEPTEMBER 30, 2020 AND WHAT WAS THE DIFFERENCE BETWEEN THAT AMOUNT AND THE AMOUNT PROJECTED TO BE PLACED INTO SERVICE?

A. The total plant in service as of September 30, 2020 was $3,891,210,000 comprised of $3,665,076,000 of gas plant and $226,134,000 of the gas division's share of common plant (I&E Ex. No. 5 Sch 4, p. 1, column D, lines 7 and 14). The difference between the FPFTY projected plant in service in the 2018 case to the actual amount of plant in service shows that UGI placed $59,781,000 less plant into service than it projected

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[1] UGI Gas Book 6, p. II-6, column 4 at Docket R-2018-3006814.

($3,950,991,000 – $3,891,210,000) (I&E Ex. No. 5, Sch. 4, p. 1, column C, line 17). Accordingly, the Company only completed 82.0% (I&E Ex No. 5, Sch 4, p. 1 column C, lines 18-20) of projected FPFTY total plant.

Q. DID YOU DETERMINE THE PERCENTAGE OF GAS PLANT ACTUALLY PLACED INTO SERVICE COMPARED TO GAS PLANT PROJECTED TO BE PLACED INTO SERVICE IN THE 2018 CASE?

A. Yes. In the 2018 rate case, the Company projected it would have $3,726,871,339 of gas plant in service as of September 30, 2020. However, the Company's actual gas plant in service was only $3,665,076,106 as of that date. This is a difference of $61,795,233 (I&E Ex. No. 5, Sch. 4, p. 1, column C, line 7). In the 2018 case, the Company projected it would add $317,833,525 of gas plant in the FPFTY (I&E Ex. No. 5, Sch. 4, p. 1, column B, line 8). Comparing these two amounts indicates that the Company only completed 80.56% (($317,833,525 - $61,795,233) / $317,833,525) of projected FPFTY gas plant (I&E Ex. No. 5, Sch. 4, p. 1, column C, lines 8-9).

Q. DID YOU DETERMINE THE PERCENTAGE OF COMMON PLANT ACTUALLY PLACED INTO SERVICE COMPARED TO COMMON PLANT PROJECTED TO BE PLACED INTO SERVICE IN THE 2018 CASE?

A. Yes. The Company projected it would have $224,119,817 of common plant in service as of September 30, 2020, in the 2018 base rate case. However, the Company's actual common plant in service was $226,134,102. This is a difference of $2,014,284 (I&E Ex. No. 5, Sch. 4, p. 1, column C, line 14). In the 2018 case, the

Company projected it would install $15,075,391 of common plant in the FPFTY (I&E Ex. No. 5, Sch. 4, p. 1, column C, line 15). Comparing these two amounts indicates that the Company completed 113.36% (($2,014,284 + $15,075,391) / $15,075,391) of projected common FPFTY plant (I&E Ex. No. 5, Sch. 4, p. 1, column C, lines 15-16).

Q. WHAT AMOUNT OF TOTAL PLANT WAS PROJECTED TO BE PLACED INTO SERVICE IN THE FPFTY IN THE 2019 BASE RATE CASE?

A. In the 2019 base rate case, the Company projected that it would have $4,324,364,000 of total plant in service in the FPFTY ending September 30, 2021.[2] This $4,324,364,000 is comprised of $4,051,159,000 of gas plant in service and $273,205,000 of the gas division's share of common plant (I&E Ex. No. 5, Sch. 4, p. 2, column B, lines 7 and 14).

Q. WHAT AMOUNT OF TOTAL PLANT WAS ACTUALLY PLACED INTO SERVICE IN THE FPFTY AND WHAT WAS THE DIFFERENCE BETWEEN THESE AMOUNTS?

A. The total plant in service as of September 30, 2021 was $4,247,028,000 comprised of $4,007,295,000 of gas plant and $239,733,000 of the gas division's share of common plant (I&E Ex. No. 5 Sch 4, p. 2, column D, lines 7 and 14). Accordingly, UGI placed $77,336,000 ($4,324,364,000 – $4,247,028,000) less plant in service than

[2] UGI Gas Book 6, p. II-5, column 4 at Docket R-2019-3015162.

projected in the 2019 base rate case (I&E Ex. No. 5, Sch. 4, p. 2, columns B to D, line 17).

Q. BREAKING THAT TOTAL PLANT DOWN EVEN FURTHER, WHAT AMOUNT OF GAS PLANT AND COMMON PLANT PROJECTED IN THE 2019 RATE CASE WAS ACTUALLY PLACED INTO SERVICE?

A. Comparing the gas plant projected to be placed into service for the FPFTY in the 2019 case with the actual gas plant placed into service indicates that the Company only completed 86.83% of projected FPFTY gas plant (I&E Ex. No. 5, Sch. 4, p. 2, column B, lines 7-9). Comparing the common plant projected to be placed into service with the actual common plant placed into service indicated that the Company completed 21.98% of projected common FPFTY plant (I&E Ex. No. 5, Sch. 4, p. 2, column C, lines 15-16).

Q. WHAT IS THE AVERAGE PERCENT OF PLANT COMPLETED IN THE LAST TWO BASE RATE CASES?

A. The average percent of gas plant completed in the last two base rate cases was approximately 83.69% and the average common plant completed in the last two base rate cases was approximately 67.67% (I&E Ex No. 5, Sch. 3, column B, lines 3 and 6).

Q. IN THE CURRENT RATE CASE, HOW MUCH GAS AND COMMON PLANT DOES THE COMPANY PROJECT IT WILL ADD IN THE FTY?

A. The Company is projecting it will add $382,709,152 of gas plant in the FTY and have $27,393,337 of corresponding retirements (UGI Gas Book 7, p. V-10). The Company also projects it will add $15,694,645 of common plant in the FTY and have $20,634,175 of corresponding retirements (UGI Gas Book 7, p. V-11).

Q. HOW MUCH OF THE PROJECTED FTY GAS AND COMMON PLANT ADDITIONS DO YOU RECOMMEND BE ALLOWED?

A. Given that the Company's average gas plant completed in the last two base rate cases was approximately 83.69% and the average common plant completed in the last two base rate cases was approximately 67.67%, I recommend that those percentages be applied to the Company's plant addition claims in this proceeding.

This recommendation results in an allowance of $320,305,000 ($382,709,152 X 0.83694) of FTY gas plant. I also applied the approximately 83.69% factor to the gas plant retirements to recommend that only $22,927,000 ($27,393,337, X 0.83694) of retirements be reflected. Similarly, applying the 67.67% to FTY common plant, results in an allowance of $10,620,000 ($15,694,645 X 0.67669). I also applied the approximately 67.67% factor to the retirements to recommend that only $13,963,000 ($20,634,175 X 0.67669) of retirements be reflected (I&E Ex. No. 5, Sch 3, column B, lines 3 and 6).

Q. BASED ON YOUR RECOMMENDATION ABOVE, WHAT TOTAL ADJUSTMENT DO YOU RECOMMEND FOR THE PROJECTED FTY GAS AND COMMON PLANT ADDITIONS?

A. This recommendation reduced projected FTY total plant in service by $56,343,000 (I&E Ex. No. 5, Sch. 2, column C, line 13).

Q. HOW MUCH GAS AND COMMON PLANT DOES THE COMPANY PROJECT IT WILL ADD IN THE FPFTY?

A. The Company is projecting it will add $413,027,000 of gas plant in the FPFTY and have $23,722,000 of corresponding retirements (UGI Gas Book 6, p. II-9). The Company also projects it will add $63,400,000 of common plant in the FPFTY and have $8,240,000 of corresponding retirements (UGI Gas Book 6, p. II-10).

Q. HOW MUCH OF THE PROJECTED FPFTY GAS AND COMMON PLANT ADDITIONS DO YOU RECOMMEND BE ALLOWED?

A. I recommend that only approximately 83.69% of projected FPFTY gas plant be included in plant in service or $345,679,000 ($413,026,743 X 0.83694). I also applied the 83.69% factor to the gas plant retirements to recommend that only $19,896,000 ($23,771,977, X 0.83694) of retirements be reflected. I also recommend that only approximately 67.67% of projected FPFTY common plant be included in plant in service or $42,902,000 ($63,400,078 X 0.67669). I also applied the approximately 67.67% factor to the retirements to recommend that only $5,576,000 ($8,239,512 X 0.67669) of retirements be reflected.

Q. BASED ON YOUR RECOMMENDATION ABOVE, WHAT TOTAL ADJUSTMENT DO YOU RECOMMEND FOR THE PROJECTED FPFTY GAS AND COMMON PLANT ADDITIONS?

A. After considering additions, and retirements for gas and common plant, I recommend projected FPFTY total plant in service be reduced by $81,305,845 (I&E Ex. No. 5, Sch. 2, p. 2, column D, line 6).

Q. WHAT IS YOUR TOTAL ADJUSTMENT TO PLANT IN SERVICE FOR BOTH THE FTY AND FPFTY?

A. The total adjustment to plant in service is $137,649,000 (I&E Ex. No. 5, Sch. 1, p. 1, column C, line 1).

Q. WHAT DID THE COMPANY CLAIM CONCERNING THE AMOUNT OF PLANT COMPLETED OVER THE PAST FIVE YEARS?

A. The Company claims that it completed 98.0% of plant budgeted over the past 5 years (UGI Book 3, Exhibit VAS-2).

Q. DO THE COMPANY'S BUDGETED AMOUNTS ON EXHIBIT VAS-2 CORRELATE WITH WHAT THE COMPANY CLAIMED IN THE RECENT BASE RATE CASE?

A. No. In the 2019 case, the Company projected it would add $405,430,000 in 2021.[3]

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[3] UGI Book 6 page II-10, Docket R-2019-3015162

However, as shown on VAS-2 the "budgeted" additions for 2021 are only $389,008,000. Furthermore, even UGI's response in standard data requirements for budget to actual capital expenditures reflect 93% actual completion in 2019, 85% actual completion in 2020, and 89% actual completion in 2021.[4] It is unclear how UGI reports a 98% completion of plant budgeted with this response in the standard data requirements.

Q. IS COMPARING THE COMPANY'S PERCENT OF BUDGETED PLANT COMPLETED A VALID COMPARISON?

A. No. As described above, the Commission should only consider the actual plant in service compared to the amount of plant claimed in the prior rate cases. The Company's "budgeted" plant amounts can be adjusted over time and may not reflect what was claimed in past cases. On the other hand, the Company's FPFTY plant amounts cannot be changed which is why that should be used for comparison. Moreover, the FPFTY amounts from the prior two cases are what the Company actually sought to recover from ratepayers and are a more accurate comparison to what it is seeking to recover in this proceeding.

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[4] UGI Book II, Attachment SDR-RR-15

Q. ARE YOU CONCERNED THAT UTILIZING THE 2020 AND 2021 PANDEMIC ERA DATA IN PERFORMING YOUR ANALYSIS WILL UNDERSTATE THE COMPANY'S COMPLETION RATE IN THIS FTY AND FPFTY?

A. No. I anticipate that supply chain difficulties, hiring difficulties, and availability of outside contractors that have been an outcome of the Covid-19 pandemic will persist through the FTY and FPFTY. My average completion rate for gas plant additions of 83.69% in this proceeding reflects my expectation of ongoing construction issues related to the pandemic.

<u>ACCUMULATED DEPRECIATION</u>

Q. WHAT IS ACCUMULATED DEPRECIATION?

A. Accumulated depreciation is the total of all prior depreciation expense plus other adjustments such as cost of removal and salvage. Accumulated depreciation reduces the value of the original cost of the plant placed into service and thus reduces rate base.

Q. IF THE COMMISSION ACCEPTS YOUR ADJUSTMENTS TO PLANT IN SERVICE SHOULD ACCUMULATED DEPRECIATION ALSO BE ADJUSTED?

A. Yes. As described below, reducing plant in service in the FTY and FPFTY reduces the accumulated depreciation that would be associated with these plant additions and reduced retirements of existing plant.

Q. WHAT ADJUSTMENT TO ACCUMULATED DEPRECIATION DO YOU RECOMMEND IF THE COMMISSION ACCEPTS YOUR ADJUSTMENTS TO PLANT IN SERVICE?

A. Accumulated depreciation should be increased from $1,315,560,000 by $8,223,000 to $1,326,783,000 (I&E Ex. No. 5, Sch. 1, p. 1, columns C and D, line 2). The accumulated depreciation by account is shown on I&E Ex. No. 5. Sch. 5, pp. 1-2, column F, lines 1-134).

Q. HOW DID YOU DETERMINE THE $1,326,783,000 ACCUMULATED DEPRECIATION FOR THE FPFTY?

A. After reducing the plant in service in the FTY as described above I recalculated the annual depreciation expense for the FTY. The recalculated annual depreciation expense was then brought forward to determine the accumulated depreciation at the beginning of the FPFTY. Then I continued the same adjustments in the FPFTY to calculate the accumulated depreciation in the FPFTY to arrive at the $1,326,783,000 (I&E Ex. No. 5, Sch. 5, p. 2, column F, line 134).

ANNUAL DEPRECIATION EXPENSE

Q. WHAT IS ANNUAL DEPRECIATION EXPENSE?

A. Depreciation is the loss of value of a utility's assets used and useful in the provision of utility service due to usage, passage of time, etc. The National Association of Regulatory Utility Commissioners defines annual depreciation expense as the annual cost associated with the diminution in the usefulness of an asset over time.

Depreciation expense is the way the return of a utility's investment is captured in rates and is generally computed by dividing the original cost of an asset by its expected useful life or by multiplying the original cost by the annual accrual rate.

Q. WHAT IS UGI'S CLAIMED ANNUAL DEPRECIATION AND AMORTIZATION EXPENSE FOR THE FTY?

A. UGI's claimed annual depreciation expense for the FPFTY ending September 30, 2023 is $114,735,000 ($106,728,000 + $8,007,000) (UGI Book V – Combined FTY, Sch. D-1, line 15). The Company determined its annual depreciation expense claim for the FTY by taking the calculated annual depreciation expense plus the amortization of net salvage and subtracted an amount charged to clearing accounts as shown on UGI Book V – Combined FTY, Sch. D-21, lines 64-66.

Q. WHAT IS UGI'S CLAIMED ANNUAL DEPRECIATION AND AMORTIZATION EXPENSE FOR THE FPFTY?

A. UGI's claimed annual depreciation expense for the FPFTY ending September 30, 2023 is $133,908,000 ($127,824,000 + $6,084,000) (UGI Book V - Combined FPFTY, Sch. D-1, line 15) and (I&E Ex. No. 5, Sch. 1, p. 2, column B, line 1). The Company determined its annual depreciation expense claim for the FPFTY by taking the calculated annual depreciation expense plus the amortization of net salvage as shown on UGI Book V – Combined FPFTY, Sch. D-21, lines 64-66.

Q. WHAT ANNUAL DEPRECIATION EXPENSE DO YOU RECOMMEND FOR THE FPFTY?

A. I recommend that the $133,908,000 of annual depreciation expense be reduced by $3,666,000 to $130,242,000 (I&E Ex. No. 5, Sch. 1, p. 2, column C and D, line 1).

Q. HOW DID YOU DETERMINE THE $130,242,000 OF ANNUAL DEPRECIATION EXPENSE FOR THE FPFTY?

A. The $130,242,000 is based on my recommendation to reduce FTY and FPFTY gas and common plant additions as described above for the FPFTY, the determination of the $130,242,000 of annual depreciation expense is shown on I&E Ex. No 5, Sch. 5, p. 2, column I, line 134.

Q. DID YOU APPLY THE SAME DEPRECIATION RATE BY ACCOUNT THE COMPANY DID TO PROJECT THE ANNUAL DEPRECIATION EXPENSE BY ACCOUNT IN THE FPFTY?

A. Yes. The annual depreciation rates on I&E Ex. No. 5, Sch. 5, columns H that I used to calculate the $130,242,000 depreciation expense are the same annual depreciation rates used by the Company in the original filing (UGI Volume 6, p. II-3 to 5).

<u>FTY AND FPFTY REPORTING</u>

Q. WHAT AMOUNT OF ADDITIONAL NET PLANT WILL BE ASSOCIATED WITH THE INCLUSION OF THE FTY ENDING SEPTEMBER 30, 2022 FOR UGI?

A. The Company’s projected addition net plant for the FTY ending September 30, 2022 is $398,404,000 (UGI Book V, FTY Sch. C-2, line 64).

Q. WHAT AMOUNT OF ADDITIONAL NET PLANT WILL BE ASSOCIATED WITH THE INCLUSION OF THE FPFTY ENDING SEPTEMBER 30, 2023 FOR UGI?

A. The Company's projected plant additions for the FPFTY ending September 30, 2023 is $476,632,000 (UGI Book V, FPFTY Sch. C-2, line 64).

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT UGI PROJECTS TO BE IN SERVICE DURING THE FTY ENDING SEPTEMBER 30, 2022 AND THE FPFTY ENDING SEPTEMBER 30, 2023?

A. Yes. I recommend that the Company provide the Commission's Bureau of Investigation and Enforcement and the Office of Consumer Advocate with an update to UGI Book 5 - Sch. C-2, no later than January 2, 2023, which should include actual capital expenditures, plant additions, and retirements by month from October 1, 2021 through September 30, 2022, and which should be filed under this docket number. I also recommend that the Company provide a similar update for actuals capital expenditures, plant additions, and retirements by month from October 1, 2022 through September 30, 2023, no later than January 2, 2024.

Q. WHY DO YOU RECOMMEND THAT UGI PROVIDE THESE UPDATES?

A. I&E believes that there is value in determining how accurately UGI projects investments in future facilities compared to the monthly actual investments and retirements that are made by the end of the FTY and FPFTY. With the use of the

FTY and FPFTY, UGI is not able to guarantee any of the projected plant additions it proposes will be completed and placed into service. Therefore, requiring the Company to provide updates of the “actual” investment and retirements by month compared to the projections used in setting rates using the FPFTY will enable the Commission to evaluate the Company’s projections used to determine rates in future rate cases.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ESYAN A. SAKAYA
PROFESSIONAL EXPERIENCE AND EDUCATION

EDUCATION:

National Association of Regulatory Utility Commissioners, Clearwater, FL
Utility Rate School; Utility Rate Making Basics, October 2019

Society of Depreciation Professionals, Philadelphia, PA
Introduction to Depreciation; Depreciation Fundamentals, September 2019

Temple University, Philadelphia, PA
Bachelor of Science; Major in Engineering Technology, 2015

Community College of Philadelphia, Philadelphia, PA
Associate of Applied Science; Major in Construction Management Technology, 2011

Island School of Building Arts, Gabriola Island, BC-Canada
Certificate Graduate: Heavy Timber Construction Aug 2002-Nov 2002

Solar Energy International, Carbondale, CO
Certificate Graduate: Basic and Advanced Photovoltaic Design, April 2002-May 2002

EXPERIENCE:

12/2018-Present

Pennsylvania Public Utility Commission-Harrisburg, PA

Fixed Utility Valuation Engineer- Assist in engineering related studies related to valuation, depreciation, cost of service, quality of service as they apply to regulated utilities. Contribute in evaluating, contrasting and conducting performance analyses in distinctive sections of valuation engineering and rate structure involving valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design. Provide expert testimony in rate related utility cases.

4/2018-12/2018

Pennsylvania Department of Transportation-Harrisburg, PA

Photogrammetry Technician I- Created three-dimensional mapping layouts of natural and man-made features from stereoscopic images on a computer workstation. Assisted in the field placement of ground based surveyed control-points prior to aerial photography acquisition. Provided field support in the use of laser scans for comprehensive digital surveying data. Operated global positioning satellite surveying equipment to obtain accurate geodetic coordinates of pre-established benchmarks.

8/2017-4/2018

Pennoni and Associates. Consulting Engineers-King of Prussia, PA

Construction Inspector-Provided quality assurance in the onsite material testing of concrete, soils, and asphalt. Read and interpreted construction drawings and specifications of materials and components. Completed daily reports regarding project progress to engineers, project managers/superintendents, contractors and clients.

TESTIMONY SUBMITTED:

I have assisted and/or submitted testimony in the following proceedings:

No.	Case
1.	UGI Gas Utilities - Gas Division, Docket Number: R-2018-3006814
2.	Newtown Artesian Water Company, Docket Number: R-2018-3006904
3.	Pittsburgh Wastewater, Docket Number: M-2018-2640803
4.	PAWC Purchase of Steelton, Docket Number: A-2019-3006814
5.	Philadelphia Gas Works, Docket Number: R-2019-3009016 - 3007636
6.	Community Utilities Water, Docket Number: R-2019-3008947
7.	Aqua Purchase of Cheltenham, Docket Number: A-2019-3008491
8.	UGI NORTH, Docket Number: R-2019-3009647
9.	UGI CENTRAL, Docket Number: R-2019-3009647
10.	UGI SOUTH, Docket Number: R-2019-3009647
11.	Twin Lakes Utilities, Docket Number: R-2019-3010958
12.	Penn Power Company, Docket: P-2019-3012628
13.	UGI Gas Utilities, Docket Number: R-2019-3015162
14.	National Fuel and Gas Distribution, Docket Number: R-2020-3015251
15.	Columbia Gas of Pennsylvania, Docket: R-2020-3018993 -3018835
16.	Duquesne Light Company, Docket Number: P-2020-3019522
17.	PA American Water Company, Docket R-2020-3019369 – 310937
18.	Bethlehem Water Company, Docket R-2020-3020256
19.	Audubon Water Company, Docket: R-2020-3020919
20.	Twin Lakes Utilities, Docket: P-2020-3020914
21.	Pike County Light and Power-Gas, Docket: R-2020-3022134
22.	Pike County Light and Power-Electric, Docket: R-2020-3022135
23.	Duquesne Light Company, Docket Number: R-2021-3024750
24.	Community Utilities Water, Docket Number: R-2021-3025206
25.	Community Utilities Wastewater, Docket Number: R-2021-3025206
26.	Hanover Municipal Water Works, Docket Number: R-2021-3026116
27.	Aqua Pennsylvania, Inc, Docket R-2021-3027385 – 3027386
28.	Aqua Purchase of Willistown, Docket Number: A-2021-3027268
29.	National Fuel and Gas Distribution, Docket Number: R-2022-3030235

I&E Statement No. 5-SR
Witness: Esyan A. Sakaya

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Surrebuttal Testimony

of

Esyan A. Sakaya

Bureau of Investigation and Enforcement

Concerning:

RATE BASE
UTILITY PLANT IN SERVICE
ANNUAL DEPRECIATION
ACCUMULATED DEPRECIATION

TABLE OF CONTENTS

INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Esyan A. Sakaya. My business address is 400 North Street, Harrisburg, PA 17120.

Q. ARE YOU THE SAME ESYAN A. SAKAYA THAT SUBMITTED DIRECT TESTIMONY ON APRIL 15, 2022?

A. Yes. I submitted I&E Statement No. 5 and I&E Exhibit No. 5.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to update and correct the recommendations and schedules contain in my direct testimony, address the rebuttal testimonies and exhibits of Vivian K. Ressler (UGI St. No. 3-R) regarding rate base, annual depreciation, and accumulated depreciation expense, and the rebuttal testimony of Vicky Schappell (UGI St. No. 5-R) concerning utility plant in service in relation to UGI Utilities, Inc. - Gas Division's ("UGI" or "Company") request for an annual increase in operating revenue of approximately $82,700,000 using the Fully Projected Future Test Year ("FPFTY") ending September 30, 2023.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. Yes, I&E Exhibit 5-SR will accompany my surrebuttal testimony. However, some exhibit references will be directed towards I&E Exhibit No. 5, which was the Exhibit to accompany my Direct Testimony identified as I&E Statement No. 5.

RATE BASE – COMPANY REVISION

Q. WHAT WAS THE COMPANY'S RATE BASE CLAIM IN THE INITIAL FILING?

A. The Company claimed a rate base of $3,169,023,000 (UGI Book V, Ex. A - Fully Projected, Sch. C-1, ln. 9 and I&E Ex. No. 5, Sch. 1, column B, p. 1, line 12).

Q. DID THE COMPANY REVISE ITS RATE BASE CLAIM IN REBUTTAL TESTIMONY?

A. Yes. The Company claimed a revised rate base of $3,176,596,000 in its Rebuttal Testimony, which is an increase of $7,573,000 ($3,176,596,000 -$3,169,023,000) over the claim in the original filing (UGI Gas - Exhibit A - FPFTY -Rebuttal, Schedule A-1, column 3, line 9).

Q. WHAT WAS THE BASIS FOR UGI'S $7,573,000 INCREASE IN RATE BASE?

A. UGI's adjusted rate base claims shown in UGI Exhibit A – FPFTY, Schedule C-1 were additions and subtractions to plant in service, accumulated depreciation, working capital, gas inventory, accumulated deferred income taxes, customer deposits, and materials and supplies. I will address the plant in service and accumulated depreciation below.

<u>UTILITY PLANT IN SERVICE – COMPANY REVISION</u>

Q. WHAT DID THE COMPANY INITIALLY CLAIM FOR UTILITY PLANT IN SERVICE AT THE END OF EACH TEST YEAR AND HOW MUCH NET PLANT WAS PROJECTED TO BE ADDED IN EACH TEST YEAR?

A. The Company's initial utility plant in service claim for the FTY ending September 30, 2022 was $4,597,404,000 (UGI Ex. A - Future, Sch. C-1, ln. 1). The Company's utility plant in service claim for the FPFTY ending September 30, 2023 is $5,042,025,000 (UGI Ex. A - Fully Projected, Sch. C-1, ln. 1). Accordingly, the total net plant additions from the FTY to the FPFTY is $444,621,000 ($5,042,025,000 - $4,597,404,000) (I&E Ex. No. 5, Sch. 2, column B, line 13 and column F line 13). The Company's utility plant in service claim for the HTY ended September 30, 2021 was $4,247,028,000 (UGI Ex A – HTY, Sch. C-1, line 1). Accordingly, the total net plant additions from the HTY to the FTY is $350,376,000 ($4,597,404,000 - $4,247,028,000) (I&E Ex. No. 5, Sch. 2, column B, line 13 and I&E Ex. No. 5, Sch. 4, column D, line 17).

Q. WHAT UTILITY PLANT IN SERVICE DID THE COMPANY CLAIM IN REBUTTAL TESTIMONY?

A. In rebuttal testimony, the Company claimed $5,041,354,000 of total utility plant in service for the FPFTY (UGI Gas Ex. A - FPFTY Rebuttal, Sch. C-1). This is a reduction of $671,000 ($5,042,025,000 - $5,041,354,000) and is shown on UGI Gas Ex. A - Rebuttal, Sch. C-2, page 3, Column 3, line 8.

Q. WHAT WAS THE BASIS FOR UGI'S $671,000 REDUCTION TO PLANT IN SERVICE?

A. UGI reduced the projected level of Mains by approximately $671,000 (UGI Gas Exhibit A - Rebuttal Schedule C-2 Column 4, line 40, page 5). The Company attributes this reduction in Mains to adjustments made in both the FTY and FPFTY to three projects that are estimated to be completed after the end of the FPFTY (UGI Gas Ex. VKR-1R).

ACCUMULATED DEPRECIATION – COMPANY REVISION

Q. WHAT ACCUMULATED DEPRECIATION DID THE COMPANY CLAIM IN THE ORIGINAL FILING?

A. In the original filing, the Company claimed $1,318,560 of accumulated depreciation as of September 30, 2023 (UGI Volume V, Sch. A-1, p. 1, line 2).

Q. WHAT ACCUMULATED DEPRECIATION DID THE COMPANY CLAIM IN REBUTTAL TESTIMONY?

A. In its rebuttal testimony, the Company lowered the accumulated depreciation to $1,318,079 as of September 30, 2023 (UGI Ex. A – Rebuttal, Sch. A-1, p. 1, line 2). This $481,000 reduction ($1,318,560 – $1,318,079) is the result of changes to the original cost of account 376 and 378 that impacted the annual depreciation expense, corrections to a service life for Allowance for Funds Used for Construction (AFUDC), and a re-allocation of depreciation expense to other UGI gas operations, (UGI FPFTY Rebuttal Ex. A, Sch. C-3, p. 5, lines 40-41).

<u>I&E RATE BASE RECOMMENDATION – REVISION</u>

Q. WHAT DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY CONCERNING PLANT IN SERVICE?

A. In direct testimony, I recommended that UGI's rate base be reduced from $3,169,023,000 to $3,023,151,000, which was a reduction of $145,872,000 (I&E Ex. No. 5, Sch. 1, p. 1, line 12).

Q. DO YOU WISH TO REVISE YOUR RECOMMENDATION IN THIS SURREBUTTAL TESTIMONY?

A. Yes. After submitting my direct testimony, I became aware of an error in my calculation for the accumulated depreciation for 2023. Therefore, I recalculated the accumulated depreciation for 2023 and incorporated this correction into my revised recommendation described below. I have also incorporated the Company's revisions to plant in service and accumulated depreciation described above in my revised recommendation. My recommendation is to reduce the revised rate base of $3,176,596,000 to $3,022,865,000, which is a reduction of $153,740,000 (I&E Ex. No. 5-SR, Sch. 1, p. 1, columns D-F, line 12).

<u>UTILITY PLANT IN SERVICE – I&E REVISION</u>

Q. WHAT DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY CONCERNING PLANT IN SERVICE?

A. In direct testimony, I recommended that UGI's $5,042,025,000 of plant in service be reduced to $4,904,376,000, which was a reduction $137,649,000 (I&E Ex. No. 5, Sch. 1, p. 1, line 1).

Q. WHAT REDUCTION TO PLANT IN SERVICE DO YOU NOW RECOMMEND?

A. As a result of the Company revising its projected plant in service, I now recommended that total plant in service be reduced by $137,539,000. This recommendation reduces the Company's rebuttal utility plant in service claim from $5,041,354,000 to $4,903,815,000 (I&E Ex. No. 5, Schedule 1-SR, p. 1, line 1, columns D-F). A breakdown of the adjustment for each plant category is shown on I&E Ex. No. 5-SR, Sch. 2, page 1. On page 1, the 2022 plant additions and adjustments are shown under columns A-D, and the plant additions and adjustments for both 2022 and 2023 are shown under columns E-H. The FPFTY alone is shown on I&E Ex. No. 5-SR, Sch. 2, page 2.

Q. WHAT WAS THE BASIS FOR YOUR RECOMMENDATION TO REDUCE PLANT IN SERVICE?

A. As stated in my direct testimony, in the last two rate cases the Company has a demonstrated history of over projecting plant relative to what has actually been placed in service (I&E St. No. 5, pp. 5-6). On average, during the 2018 and 2020 cases, the Company only completed 83.694% of FPFTY gas plant and 67.669% of FPFTY common plant (I&E Ex. No. 5, Sch. 3, lines 3 and 6).

Q. DID THE COMPANY DISAGREE WITH YOUR RECOMMENDATION TO REDUCE FTY AND FPFTY PLANT IN SERVICE PROJECTIONS?

A. Yes, for several reasons. First, the Company claims that the proper comparison is to budgeted plant additions and not plant projected in past rate cases and that I&E disregarded UGI's budgeting process. Second, the Company claims that the appropriate time to evaluate the proper comparison of plant placed into service is to compare 3 to 5 years. Third, the Company attempts to dispute the use of a two-year period during the Covid-19 pandemic. Fourth, the Company believes the Commission should consider inflation in this case when evaluating past performance. Fifth, the Company claims that my methodology does not take into considerations adjustments made in settlements. Sixth, the Company believes that I did not properly account for retirements. Seventh, the Company believes that I improperly separated gas plant and common plant in my analysis. Finally, the Company disputes that it earned a return on plant that it did not place into service (UGI St. No. 5-R, pp. 5-7).

Q. WHAT METHODOLOGY DID YOU USE IN YOUR FTY AND FPFTY PLANT PROJECTIONS?

A. The methodology I used is called "variance analysis." It is an accounting methodology that compares predicted and actual outcomes. The details of this analysis are described in my direct testimony and the results are summarized on I&E Ex. No. 5, Sch. 1, pp 1-2.

Q. WHAT IS VARIANCE AND HOW DOES IT APPLY TO UTILITY ACCOUNTING?

A. Variance in accounting is the difference between a forecasted amount and the actual amount (Forecast – Actual = Variance). As stated below, in the past two rate cases at

Dockets R-2018-3006814 and R-2020-3015162, UGI did not meet or exceed its initially forecast projections. The actuals for the past two rate cases were below forecast. Because of these inaccurate forecasts, the Company can unfairly pass its claimed plant additions to ratepayers through the established revenue requirement without placing the claimed plant into service.

Q. WHAT DID THE COMPANY CLAIM CONCERNING THE AMOUNT OF PLANT COMPLETED OVER THE PAST FIVE YEARS?

A. The Company claims that it completed 98.0% of plant budgeted over the past five years (UGI St. 5-R, p. 10 and Book 3, Exhibit VAS-2).

Q. SHOULD COMPANY "BUDGETED" AMOUNTS BE USED TO DETERMINE THE PERCENTAGE OF PLANT COMPLETED AS SUGGESTED BY THE COMPANY?

A. No, for several reasons. First, rates are not based upon "budgeted" plant additions, rates are based upon FTY and FPFTY plant claimed in base rate filings. They are two different things. In the 2019 base rate case, the Company projected it would add $405,430,000 in 2021.[1] However, as shown on UGI Ex. VAS-2 the "budgeted" additions for 2021 were only $389,008,000. Therefore, the Company is claiming, and potentially recovering, much more in base rate cases than what it is actually budgeting. Second, budgets can be adjusted as time progresses and there is no indication when the "budgeted" amounts on UGI Ex. VAS-2 were prepared or

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1 UGI Book 6, p. II-10, at Docket R-2019-3015162

adjusted. Finally, a review of a UGI's standard data requests for the last three rate cases at Dockets R-2018-3006814, R-2019-3015162 and R-2021-3030218 reflects a 93% actual completion in September of 2019 at Docket R-2018-3006814[2]. When comparing the plant claimed at Docket R-2018-3006814 to amount being claimed at Docket R-2019-3015162 only 85% actual plant was completed in September of 2020[3]. Finally, when comparing the actual plant placed into service from Docket R-2019-3015162 into Docket R-2021-3030218 only of 89% actual plant was completed in September of 2021.[4] Therefore, utilizing a variable changing "budget" amount for comparison instead of a fixed rate base claim is not valid and should be discarded for comparison purposes.

Q. IS COMPARING THE COMPANY'S PERCENT OF BUDGETED PLANT COMPLETED A VALID COMPARISON?

A. No. As described above, and in my direct testimony, the Commission should only consider the actual plant in service compared to the amount of plant claimed in the prior rate cases. The Company's "budgeted" plant amounts can be adjusted over time and may not reflect what was claimed in past cases. On the other hand, the Company's FPFTY plant projections amounts cannot be changed which is why that should be used for comparison. Moreover, the FPFTY amounts from the prior two cases are what the Company actually sought to recover from ratepayers and are a more accurate comparison to what it is seeking to recover in this proceeding.

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[2] UGI Book 2, SDR-RR-15, at Docket R-2018-3006814
[3] UGI Book 2, SDR-RR-15, at Docket R-2019-3015162
[4] UGI Book 2, SDR-RR-15, at Docket R-2021-3030128

Q. WHAT DID THE COMPANY CLAIM CONCERNING THE TIME PERIODS COVERED BY I&E'S ANALYSIS?

A. The Company believes my two-year analysis is not long enough to make the plant comparisons valid. In addition to this, UGI mentions past rate base cases of other companies that made use of a regulatory requirement that required a longer time period to justify plant additions (UGI St. No. 5-R, pp. 7-9).

Q. ARE THE COMPANY'S CONCERNS REGARDING THE SHORTER TIME PERIOD VALID?

A. No. I believe a two-year review is sufficient to evaluate the Company's success at meeting FPFTY projections. I am not aware of any minimum review period for comparing plant additions.

Q. DID THE COMPANY PROVIDE A LONGER COMPARISON OF FTY AND FPFTY PLANT IN SERVICE THAT WOULD DEMONSTRATE YOUR ANALYSIS IS UNRELIABLE?

A. No. If the Company had evidence that over the last three or more years or cases, that it actually installed all the projected FTY and FPFTY plant, it should have provided this analysis to support its allegation. However, the Company failed to provide this analysis, which leads me to believe that including more years would have produced similar results.

Q. WHAT ADDITIONAL TESTIMONY DOES THE COMPANY PROVIDE TO ATTEMPT TO SUPPORT ITS CLAIM THAT THREE YEARS IS THE ONLY VALID TIME PERIOD TO EVALUATE THE LEVEL OF PLANT INSTALLED?

A. The Company claims it is important that the 52 Pa Code 53.53 filing requirement requires a utility to provide a three-to-five-year comparison of measure of value to determine the reasonableness of the projected measure of value while making no reference to a two-year period comparison (UGI St. 5-R, pp. 8-9).

Q. SHOULD THE COMMISSION BASE ITS DETERMINATION OF PLANT IN SERVICE ON ONLY ONE FILING REQUIREMENT?

A. No, for two reasons. First, filing requirements simply describe what a utility must provide in a rate case. There is nothing in this filing requirement that limits, directs, or instructs the Commission that it must makes its decision based solely on this filing requirement. Second, as described above, if the Company had evidence to support its claim that over the past 5 years, it completed more plant than projected in the FTY or FPFTY, it should have provided it. Therefore, the claim that the Commission is somehow limited to the data originally provided in 52 Pa Code 53.53 is incorrect.

Q. WHAT DOES THE COMPANY CLAIM CONCERNING PANDEMIC DELAYS?

A. The Company believes my recommendation should be rejected because the time-period I evaluated includes time during the Covid-19 pandemic, and despite the pandemic, it still completed 98% of budgeted plant additions over the past five years (UGI St. No. 5-R, p. 10).

Q. WHY IS THIS ARGUMENT INVALID?

A. Again, the Company erroneously believes the Commission should compare "budgeted" plant additions to actual plant additions as opposed to those plant additions claimed for rate recovery in base rate cases. As described above, this comparison has no value and is substantially misleading relative to what the Company requested for inclusion in rates. To further respond, a review of current events in the news indicates that a continuation of supply chain difficulties, hiring difficulties, and availability of outside contractors as the result of the Covid-19 pandemic will persist through the FTY and FPFTY, which will continue to impact the Company's ability to complete plant addition projections.

Q. WHAT DOES THE COMPANY CLAIM CONCERNING INFLATION?

A. The Company claims that inflation has not been a factor in contracts up to the early part of 2022 but will be from now on. The Company states that the higher inflated contract costs are not included in the FTY or FPFTY plant projections but are now reasonably known and measurable (UGI St. No. 5-R, p. 11-12).

Q. DOES INFLATION OR THE POSSIBILITY OF INFLATION MATTER?

A. No. If inflation increases the unit cost of investments, UGI can still invest the original "budgeted" dollar amount, but less physical plant will be installed since the unit price will increase. Therefore, the Company's claim that somehow inflation negates the fact that they failed to invest in the level of FPFTY described in past rate cases is not valid. Since my analysis was based on dollars of plant claimed for addition in a rate case to dollars of plant actually added, the Company's attempt to relate the shortfall to inflation is without merit. In fact, the higher cost of materials and labor would have caused the Company to exceed its rate case projection if it had achieved the actual physical plant project completion it had claimed in its rate cases.

Q. WHAT DOES THE COMPANY CLAIM CONCERNING THE LEVEL OF PLANT IN RECENT CASES?

A. The Company believes that my recommendation is flawed because I did not consider that in both the 2019 and 2020 Gas Base Rate Cases, the Company reduced its initially filed total plant in service claims for the FPFTY downward, thus making it appear UGI was less successful in installing plant in service than it actually was (UGI St. No. 5-R, pp. 16-17).

Q. IS IT VALID TO ARGUE THAT MY METHODOLOGY IS FLAWED BECAUSE PLANT ACCOUNTS WERE ADJUSTED IN PAST CASES?

A. No. First, the Company made only de minimis charges to its plant addition projections during the rebuttal phases of the past two cases. Second, my recommendation was based upon the original filing because I could not anticipate future plant changes agreed to or proposed by the Company after the initial case was filed. In addition, as described above, I incorporated the most recent plant additions and plant in service claims to establish my revised surrebuttal recommendation.

Q. WHAT DOES THE COMPANY CLAIM CONCERNING THE LEVEL OF RETIREMENTS IN THE CALCULATION OF THE PLANT PROJECTIONS?

A. The Company believes that my methodology failed to properly account for all the projected retirements (UGI St. No. 5-R, pp. 18-19).

Q. IS THIS A VALID ARGUMENT?

A. No. First, my recommendation has been revised to properly account for retirements, cost of removal, and salvage. My response to UGI-II-1 indicated a correction was required, which as described above, is incorporated in my revised recommendation. Second, retirements were properly adjusted to account for the fact that if plant is not placed into service, retirements will not occur.

Q. WHAT DOES THE COMPANY CLAIM CONCERNING THE LEVEL OF GAS PLANT AND COMMON PLANT?

A. The Company believes that my methodology is flawed because I analyzed gas plant and common plant separately. The Company claims that my analysis is flawed because it does not budget plant that way, and recommends my methodology be changed to account for this (UGI St. No. 5-R, pp. 18-19).

Q. PLEASE EXPLAIN WHY YOU ANALYZED GAS PLANT AND COMMON PLANT SEPARATELY.

A. I analyzed gas plant and common plant separately because I determined the percentages of completed plant were different for each type of plant. In addition to this, the Company provided exhibits showing annual accumulated depreciation, along with a set of associated spreadsheets that provided a separate breakdown of gas and common plant. The fact that the Company doesn't "budget" plant additions this way is irrelevant. As described above, the amounts and how they are presented in a base rate case is what should be considered. Since the Company separates gas plant and common plant in rate cases, it is reasonable to separate gas plant and common plant when evaluating the percent completion rate for each type. Therefore, it is not necessary to revise my methodology and recalculate my recommendation as suggested by the Company (I&E Exhibit No. 5-SR, Sch. 2, p, 1).

Q. WHAT DOES THE COMPANY CLAIM CONCERNING RETURN ON PLANT NOT PLACED INTO SERVICE?

A. The Company believes that since the cases were "black box" settlements they did not earn the return they requested in those cases. Therefore, the Company believes that it is incorrect to assert that it earned a return based upon the projected additions in each case (UGI St. No. 5-R, pp. 22-23).

Q. PLEASE ADDRESS THE COMPANY'S ASSERTION THAT SINCE THESE CASES WERE SETTLED IT DID NOT EARN A RETURN BASED UPON PROJECTED ADDITIONS IN EACH CASE?

A. In a black box settlement, because it is unlikely that all parties could agree on the specific adjustments, the adjustments each party used to reach the agreed upon revenue requirement are not specified. Therefore, the FTY and FPFTY plant that was claimed is assumed to be embedded in the settlement as plant additions relate to provision of safe and reliable service, so even if the Company earned a lower rate of return than desired or claimed, that plant, which was presumed to be installed during the impending rate year, does earn a return. In fact, the DSIC implementation paragraph included in most settlements uses the Company's claimed FPFTY rate base as the DSIC trigger point, which reinforces my position that claimed plant remains intact, even in black box settlements.

ACCUMULATED DEPRECIATION – I&E REVISION

Q. WHAT DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY CONCERNING ACCUMULATED DEPRECIATION?

A. I recommended that accumulated depreciation be increased from $1,318,560,000 to $1,326,783,000, which is an increase of $8,223,000 (I&E Ex. No. 5, Sch. 1, p. 1, line 2). The rational for increasing accumulated depreciation was provided on I&E St. No. 5, p. 14.

Q. DUE TO COMPANY AND I&E REVISIONS TO PLANT IN SERVICE, WHAT ADJUSTMENT TO ACCUMULATED DEPRECIATION DO YOU RECOMMEND IN SURREBUTTAL TESTIMONY?

A. As described above, after my direct testimony was filed, I discovered and error in my calculation. Correcting this error together with incorporating the Company's revisions described in its rebuttal testimony, results in me recommending that that the Company's revised accumulated depreciation be increased from $1,318,079,000 to

$1,334,279,000 which is an increase of $16,200,000 (I&E Ex. No. 5-SR, Sch. 1, p. 1, columns D, E, and F, line 2). The accumulated depreciation by account is shown on I&E Ex. No. 5-SR. Sch. 3, pp. 1-2 column F, lines 1-134).

Q. HOW DID YOU DETERMINE THE $1,334,279,000 ACCUMULATED DEPRECIATION FOR THE FPFTY?

A. After reducing the plant in service in the FTY as described above, I recalculated the annual depreciation expense for the FTY. The recalculated annual depreciation expense was then brought forward to determine the accumulated depreciation at the beginning of the FPFTY. Then I continued the same adjustments in the FPFTY to calculate the accumulated depreciation in the FPFTY to arrive at the $1,334,279 000 (I&E Ex. No. 5-SR, Sch. 3, column F, line 134, p. 2).

Q. IF THE COMMISSION ACCEPTS YOUR ADJUSTMENTS TO PLANT IN SERVICE, SHOULD ACCUMULATED DEPRECIATION ALSO BE ADJUSTED?

A. Yes. As described above, reducing plant in service in the FTY and FPFTY reduces the accumulated depreciation that would be associated with these plant additions and reduces retirements of existing plant.

<u>ANNUAL DEPRECIATION EXPENSE – I&E REVISION</u>

Q. WHAT DID YOU RECOMMEND IN YOUR DIRECT TESTIMONY CONCERNING ANNUAL DEPRECIATION EXPENSE?

A. I recommended that annual depreciation expense be reduced from $133,908,000 to

$130,242,000 which is a decrease of $3,666,000 (I&E Ex. No. 5, Sch. 1, p. 2, line 1). The rational for decreasing annual depreciation expense was provided in I&E St. No. 5, p. 15.

Q. DUE TO COMPANY AND I&E REVISIONS TO PLANT IN SERVICE, WHAT ADJUSTMENT TO ANNUAL DEPRECIATION EXPENSE DO YOU RECOMMEND IN SURREBUTTAL TESTIMONY?

A. I recommend that annual depreciation expense be decreased from $133,134,000 to $129,641,000. This is a reduction of $3,494,000 (I&E Ex. No. 5-SR, Sch. 1, p. 2, columns B, C and D, line 1). The annual depreciation expense by account is shown on I&E Ex. No. 5-SR. Sch. 3, p. 2, column D, line 1).

Q. HOW DID YOU DETERMINE THE $129,641,000 ANNUAL DEPRECIATION EXPENSE FOR THE FPFTY?

A. After adjusting the projected plant in service in the FTY and FPFTY as described above, I recalculated the annual depreciation expense for the FPFTY based upon the same service lives the Company used for each plant account to arrive at the $129,641,000 (I&E Ex. No. 5-SR, Sch. 3, pp. 1-2, column I, lines 1-134).

Q. IF THE COMMISSION ACCEPTS YOUR ADJUSTMENTS TO PLANT IN SERVICE, SHOULD ANNUAL DEPRECIATION EXPENSE ALSO BE ADJUSTED?

A. Yes. As described above, reducing plant in service in the FTY and FPFTY reduces the annual depreciation expense that would be associated with these plant additions and reduced retirements of existing plant.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 6
Witness: Jessalynn Heydenreich
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Direct Testimony

of

Jessalynn Heydenreich

Bureau of Investigation & Enforcement

Concerning:

PIPELINE REPLACEMENT COSTS
SYSTEM LEAK REDUCTION

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INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Jessalynn Heydenreich. I am a Fixed Utility Valuation Engineer in the Pipeline Safety Division of the Pennsylvania Public Utility Commission's (Commission) Bureau of Investigation and Enforcement (I&E). My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?

A. I attended the Pennsylvania State University and earned a Bachelor of Science Degree in Mechanical Engineering in 2003. I joined the Pennsylvania Public Utility Commission's Pipeline Safety Division in October 2015.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to address UGI Utilities, Inc. - Gas Division's (UGI or Company) pipeline replacement costs, particularly restoration costs, associated with the replacement of mains.

Q. DOES YOUR TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 6 contains schedules relating to my testimony.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF UGI WITNESS MR. ANGSTADT AS IT RELATES TO UGI'S PLAN TO REPLACE CAST IRON AND BARE STEEL PIPELINES?

A. Yes. I have reviewed Mr. Angstadt's direct testimony as it relates to UGI's plan to replace cast iron and bare steel pipelines.[1] Replacement and betterment infrastructure projects are chosen for inclusion in the capital budget using a risk-based prioritization process.[2] Mr. Angstadt summarizes UGI's risk-based prioritization process used to evaluate the replacement of cast iron and bare steel pipelines. Mr. Angstadt states that UGI's cast iron and bare steel mains are more susceptible to failure than other pipe materials. Mr. Angstadt also references UGI's Long Term Infrastructure Improvement Plan (LTIIP) to prioritize projects for its' capital budget. UGI uses a risk-based prioritization process Distribution

[1] UGI Statement No. 9, pp. 10, ln 8-15.
[2] UGI Statement No. 9, p. 9-10.

Integrity Management Program (DIMP) to determine which pipelines should be replaced.

Q. WHAT FEDERAL AND STATE REGULATIONS CONTROL UGI'S PIPELINE REPLACEMENT?

A. UGI is mandated to implement a DIMP under Chapter 49 CFR 192 Subpart P – Gas Distribution Pipeline Integrity Management (IM) of the Code of Federal Regulations. Additionally, utilities, like UGI, which are seeking to continue a previously-approved DSIC mechanism, are required to submit an LTIIP pursuant to 52 Pa Code §121.1 and §121.3.

Q. WHY MUST A NATURAL GAS DISTRIBUTION COMPANY COMPLY WITH THE DIMP REGULATIONS?

A. The Pipeline and Hazardous Material Safety Administration (PHMSA) created DIMP regulations to reduce the number of U.S. Department of Transportation (U.S. DOT) Reportable Incidents.[3] DIMP is a performance based regulatory program required of gas distribution operators and is driven by risk management.

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[3] A PHMSA Reportable Incident is defined by the following events: (1) An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:(i) A death, or personal injury necessitating in-patient hospitalization;(ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;(iii) Unintentional estimated gas loss of three million cubic feet or more;(2) An event that results in an emergency shutdown of an LNG facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident;.(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) of this definition.

Q. WHY MUST A NATURAL GAS DISTRIBUTION COMPANY FILE AN LTIIP?

A. A natural gas distribution company must submit an LTIIP for Commission approval to be eligible to recover the reasonable and prudently incurred costs regarding the repair, improvement, and replacement of eligible property from the Distribution System Improvement Charge (DSIC). The LTIIP must show the acceleration of the replacement of aging infrastructure by the utility and be sufficient to ensure and maintain adequate, efficient, safe, reliable, and reasonable service to customers.[4]

Q. WHAT ARE THE REQUIREMENTS OF A DIMP?

A. DIMP requires gas distribution pipeline operators to:

1. Demonstrate knowledge of the gas distribution system;
2. Identify threats;
3. Evaluate and rank risks;
4. Identify and implement measures to address risk;
5. Measure performance, monitor results and evaluate effectiveness;
6. Evaluate and improve the DIMP;
7. Report results.

[4] See 52 Pa. Code § 121.1.

DIMP requirements include the identification of threats to pipeline facilities and the requirement for operators to create plans to mitigate and reduce the risks caused by those threats. UGI uses a risk-based prioritization process to select pipelines for replacement. UGI determines pipeline replacements by managing the risk ranking of the different aspects of the pipeline and then replacing the pipe based on the highest risk ranking.

Q. WHAT ARE THE REQUIREMENTS OF AN LTIIP?

A. The LTIIP must include the following elements:

1. Identification of types and age of eligible property owned and operated by the utility for which it is seeking DSIC recovery.
2. An initial schedule for planned repair and replacement of eligible property.
3. A general description of location of eligible property.
4. A reasonable estimate of quantity of eligible property to be improved or repaired.
5. Projected annual expenditures and means to finance the expenditures.
6. A description of the manner in which infrastructure replacement will be accelerated and how repair, improvement, or replacement will ensure and maintain adequate, efficient, safe, reliable, and reasonable service to customers.

7. A workforce management and training program designed to ensure that the utility will have access to a qualified workforce to perform work in a cost-effective, safe, and reliable manner.
8. A description of a utility's outreach and coordination activities with other utilities, Department of Transportation and local governments regarding the planned maintenance/construction projects and roadways that may be impacted by the LTIIP.

The LTIIP must address only the specific property eligible for DSIC recovery.[5]

Q. WHAT ARE THE COMMON MITIGATION MEASURES FOR HIGH RISK PIPELINE SEGMENTS?

A. The industry's common mitigation measure to reduce pipeline risk is to replace the highest risk pipelines first. As a company replaces the pipelines calculated to be at the highest risk, the total system risk should be reduced. The overall risk of the asset group will reduce as the riskiest pipeline is replaced, if enough pipe is replaced in that asset group annually to overcome the increasing risks on other segments within that group.

[5] See 52 Pa. Code § 121.3.

Q. SHOULD PIPELINE REPLACEMENT MITIGATION MEASURES BE BASED ON LTIIP OR DIMP?

A. Pipeline replacement, which includes high risk cast iron and bare steel should be based on DIMP. The LTIIP is a forward-looking plan for the replacement of DSIC eligible assets. Overall, pipeline replacement should be risk based and, thus, driven by DIMP.

<u>RESTORATION COSTS</u>

Q. WHAT IS INCLUDED IN UGI's PIPELINE REPLACEMENT COSTS?

A. UGI's capital costs include Contractor, Material, Other, Restoration, Labor, Equipment, and Overhead.

Q. ARE THE PIPELINE REPLACEMENT COSTS INCREASING?

A. Yes. UGI's pipeline replacement costs are increasing. {**BEGIN PROPRIETARY**}

{**END PROPRIETARY**}

Q. DOES THE TOTAL COST FOR PIPELINE REPLACEMENT INCLUDE THE COSTS ASSOCIATED WITH SERVICE LINE REPLACEMENT?

A. No. {**BEGIN PROPRIETARY**}

{**END PROPRIETARY**}

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Q. WHAT PORTION OF UGI'S PIPELINE REPLACEMENT COSTS ARE INCREASING AT THE GREATEST RATE PER MILE?

A. The largest increase in pipeline replacement is associated with the restoration costs per mile. {**BEGIN PROPRIETARY**} {**END PROPRIETARY**}

Q. WHAT ARE UGI'S FORECASTED PIPELINE REPLACEMENT GOALS?

A. Pipeline replacement goals for 2022, 2023 and 2024[8] are known to be at least 70 miles per year, which is representative of the actual pipeline replacement rate of 76 miles in fiscal year 2021. Beyond Fiscal Year 2024, UGI's pipeline replacement goals will be determined in a new LTIIP filed with the Commission.

Q. HAS THE COMPANY COMMENTED ON THE INCREASING RESTORATION COSTS?

A. Yes. UGI indicated in the response to I&E-PS-29, that it is continuing efforts to lower restoration costs with a strategy focused on three main areas: municipal outreach, project aggregation, and installation technology.

[8] See UGI Statement No. 9, p 10, ln 8-15.

Q. IN YOUR OPINION, WILL UGI'S RESTORATION COSTS PER MILE INCREASE IN 2022 AND THROUGH 2024?

A. Yes. {**BEGIN PROPRIETARY**}

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[9] See Exhibit No. 6, Schedule No. 2.
[10] See Exhibit No. 6, Schedule No. 1.

{**END PROPRIETARY**}

Q. DO INCREASING RESTORATION COSTS NEGATIVELY IMPACT UGI'S CAPITAL SPENDING ON PIPELINE REPLACEMENT PROJECTS?

A. Yes. {**BEGIN PROPRIETARY**}

{**END PROPRIETARY**}

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Q. WHEN CAPITAL IS UTILIZED FOR MORE ANCILLARY SPENDING SUCH AS RESTORATION COSTS, DO THOSE ADDED COSTS REDUCE THE FUNDS AVAILABLE FOR PIPELINE REPLACEMENT?

A. Yes. The increasing restoration costs divert funds from UGI's pipeline replacement projects. The fewer projects UGI can complete in a year equates to less risky pipe being replaced, which slows the desired reduction in total pipeline risk. The less money UGI spends on restoration costs, the more funds it has for pipeline replacement.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING RESTORATION COSTS?

A. Yes. I recommend that UGI continue to take affirmative steps to reduce restoration costs through efforts including, but not limited to, coordinating pipe replacement projects with other street projects and replacing pipe using trenchless construction techniques where technically and economically feasible. I also recommend UGI produce by March 2023 for FY 2022 pipeline replacements and annually thereafter for subsequent years and discuss the results of the audits of the restoration costs for its 10 largest projects in the prior three years, identifying costs incurred in excess of the Pennsylvania Department of Transportation restoration standards including: paving, shoulders, sidewalks, etc., and permitting fees.

<u>LEAK IDENTIFICATION</u>

Q. PLEASE DESCRIBE HOW UGI CLASSIFIES LEAKS ON ITS SYSTEM?

A. UGI assigns grades to leaks on its system according to the severity of the leaks. These assignments include Class 'A', 'B', and 'C'. Class 'C' leaks are deemed hazardous and repaired immediately. Class 'B' leaks may become hazardous if otherwise not repaired and are scheduled for repair within twelve (12) months, not to exceed fifteen (15) months. Class 'A' are deemed non-hazardous leaks.

Q. HOW HAVE UGI'S LEAKS TRENDED FROM 2017 TO 2021?

A. In response to I&E-PS-15, the Company provided historic leak information. {**BEGIN PROPRIETARY**}

{**END PROPRIETARY**}

Q. DO YOU HAVE A RECOMMENDATION REGARDING UGI'S LEAKS?

A. Yes. I recommend UGI perform a root cause analysis to determine why the increase in total number of leaks found in 2021 does not correlate with removing 60 miles of risky pipeline in 2020. Further, I recommend UGI present the findings

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of said analysis to I&E Pipeline Safety, including any corrective actions the Company takes, no later than September 30, 2022.

Q. WHY DO YOU RECOMMEND UGI COMPLETE A ROOT CAUSE ANALYSIS REGARDING THE UPWARD TREND OF LEAKS ON ITS SYSTEM?

A. The increase of UGI's leaks in the last year is concerning given the amount of priority pipe the Company has been replacing. [14] Theoretically, as risky pipes are replaced, the number of leaks should go down, which is not the case here. A root cause analysis would be a good investment of ratepayers' money given the threats leaks pose to life and property.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes

[14] See Exhibit No. 6, Schedule No. 3 (Proprietary).

I&E Statement No. 6-SR
Witness: Jessalynn Heydenreich

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

Docket No. R-2021-3030218

Surrebuttal Testimony

of

Jessalynn Heydenreich

Bureau of Investigation & Enforcement

Concerning:

PIPELINE REPLACEMENT COSTS
SYSTEM LEAK REDUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Jessalynn K. Heydenreich. I am a Fixed Utility Valuation Engineer in the Pipeline Safety Division of the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E"). My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. ARE YOU THE SAME JESSALYNN K. HEYDENREICH WHO SUBMITTED DIRECT TESTIMONY ON BEHALF OF THE BUREAU OF INVESTIGATION AND ENFORCEMENT?

A. Yes. I submitted I&E Statement No. 6 and I&E Exhibit No. 6.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address the rebuttal testimony of UGI Utilities – Gas Division ("UGI") witness Timothy J. Angstadt's testimony identified as UGI Statement No. 9-R concerning UGI's pipeline replacement costs and system leaks.

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. I stated in my direct testimony that restoration costs associated with pipeline replacement are increasing and mitigation of the increases were suggested.

Additionally, I discussed the system leak history and increase in documented leaks for 2021 and how that would pertain to the Distribution Integrity Management Program ("DIMP") to determine which pipelines should be replaced.

Q. DID MR. ANGSTADT ADDRESS YOUR DIRECT TESTIMONY IN HIS REBUTTAL TESTIMONY?

A. Yes. Mr. Angstadt replied to my direct testimony by stating UGI Utilities has plans going forward to reduce restoration costs of pipeline replacement, but he specifically disagrees with my representation that restoration costs have impacted pipeline replacement as UGI remain on track with its filed long term infrastructure improvement plan (UGI St. No. 9-R, pp. 8-10). Additionally, Mr. Angstadt stated that UGI utilizes varying leak survey intervals and due to the variability of leak rates in different assets, some year-to-year leak detection volatility is to be expected. (UGI St. No. 9-R, p. 11)

Q. DO YOU AGREE WITH MR. ANGSTADT THAT RESTORATION COSTS WILL NOT NEGATIVELY IMPACT PIPELINE REPLACEMENT RATES?

A. Not necessarily. Utilities do not have unlimited funds. The more money it costs to replace pipeline, which would include restoration costs, it follows that less pipeline can be replaced simply because utilities do not have unlimited funds. While it may not match dollar for dollar, I believe that if restoration costs continue to rise, it will necessarily follow that the utility will not be able to replace as much pipeline as it would at lower restoration costs.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING RESTORATION COSTS?

A. Yes. Mr. Angstadt stated the remaining cast iron and bare steel is in more urban areas and will incur higher replacement costs (UGI St. No 9-R at 6-7). I agree the replacement costs will increase and the rate of increase will likely exceed my previous calculations. This simply serves to illustrate the importance of UGI's efforts to reduce restoration costs associated with replacement of cast iron and bare steel pipelines.

Q. DID MR. ANGSTADT AGREE WITH ANY OF YOUR RECOMMENDATIONS RELATED TO RESTORATION COSTS?

A. Yes. Mr. Angstadt stated that UGI will continue its efforts to control restoration costs by coordinating projects where it can and using technology that will reduce restoration activities, as well as taking other actions to reduce restoration costs. In addition, UGI has agreed that it will prepare and submit an annual report to the Gas Safety Division on March 1 which will identify the ten most expensive restoration projects per year over the past three years with the corresponding cost breakdowns (UGI St. 9-R, p. 10).

Q. IS MR. ANGSTADT'S STATEMENT OF LEAK VOLATILITY DUE TO UGI'S VARIED INSPECTION SCHEDULE AN ADEQUATE EXPLANATION FOR THE INCREASE IN LEAKS IN 2021?

A. No. In UGI St. No 9-R, Figure 1, UGI indicates they repair fewer leaks annually as proof that the main replacement program is working; however, system improvement must include a decrease in new leaks, not just a decrease in the repair of existing leaks. Therefore, this figure is not illustrative of the total leaks on the pipeline system. Class 'A' and 'B' leaks are historically found during leak surveys, which have a variable inspection cycle by asset type. Class 'C', which are hazardous leaks, are generally found due to odor complaints and because of pipeline damage. An increase in the number of leaks in 2021 over 2020 may indicate that the riskiest pipeline in UGI's pipeline system has not been replaced.

Q. FOR PIPELINE ASSETS HAVING A LEAK INSPECTION CYCLE LESS FREQUENTLY THAN ONCE PER YEAR, WOULD DIMP ADDRESS THESE ASSETS ON AN ANNUAL BASIS?

A. Yes, pipeline assets are ranked annually by DIMP, with the goal of reducing risk to the pipeline system. Mr. Angstadt stated that there are variable inspection cycles for different asset types (UGI St. No. 9-R, p. 11). Pipeline assets are still evaluated annually in an effective DIMP to reduce pipeline system risk, regardless of the leak inspection cycle.

Q. WHAT WAS MR. ANGSTADT'S RESPONSE TO YOUR PROPOSAL THAT UGI COMPLETE A ROOT CAUSE ANALYSIS TO DETERMINE WHY LEAKS INCREASED FROM 2020 TO 2021?

A. Mr. Angstadt said that because the level of increase was small, he did not believe further analysis was necessary (UGI St. No. 9-R, p. 12).

Q. DO YOU CONTINUE TO RECOMMEND UGI COMPLETE A ROOT CAUSE ANALYSIS?

A. Yes. It is important to determine the cause of any increase in leaks even if it is a modest increase. Therefore, I continue to recommend UGI complete a root cause analysis.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes